OKLAHOMA CITY, Feb. 24, 2016 /PRNewswire/ -- Chesapeake Energy Corp. (NYSE: CHK) today provided financial and operational guidance for 2016 and reported financial and operational results for the 2015 full year and fourth quarter. Highlights include:

- Planned 2016 total capital expenditures ranging from $1.3 to $1.8 billion, approximately 57% lower than 2015 levels
- Projected 2016 production decline of 0% to 5%, adjusted for asset sales
- $700 million in asset divestitures closed or under signed sales agreements since year-end 2015; $500 million in net proceeds after repurchase of three Volumetric Production Payments
- Targeting an additional $500 million to $1 billion in asset divestitures in 2016
- Average 2015 production of approximately 679,200 boe per day, an increase of 8% year over year, adjusted for asset sales
- 2015 adjusted net loss of $0.20 per fully diluted share and 2015 adjusted ebitda of $2.385 billion

Doug Lawler, Chesapeake's Chief Executive Officer, commented, "In light of the challenging commodity price environment, our focus for 2016 is to improve our liquidity, further reduce our cost structure and address our near-term debt maturities to strengthen our balance sheet. Our tactical focus areas remain asset divestitures, of which we are pleased to have approximately $500 million in net proceeds closed or under signed sales agreements, liability management and open market purchases of our bonds. We are also renegotiating gathering, transportation and processing contracts to better align with our current development plans and market conditions, aggressively working to minimize the decline of our base production and making shorter-cycle investments with our 2016 capital program. We have set our initial capital program for the year at $1.3 to $1.8 billion, including capitalized interest, and will remain flexible to raise or lower based on commodity prices."

2016 Capital Program and Production Outlook

Chesapeake is budgeting total capital expenditures (including capitalized interest) of $1.3 to $1.8 billion for 2016. Using the midpoint of the range, this represents a 57% reduction from the company's 2015 total capital expenditures of $3.6 billion. The company's planned 2016 capital program will be focused on shorter cash cycle projects that generate positive rates of return in today's commodity price environment and in mitigation of the company's commitment obligations. As a result, Chesapeake's planned 2016 capital program will be dedicated to more completions and less drilling, with total completion spending representing approximately 70% of the company's total drilling and completion program. This program, combined with the improving quality of the company's operations, its capital efficiency and lower service costs will provide incrementally positive economics, even in today's commodity price environment.

In 2016, Chesapeake plans to place approximately 330 to 370 wells on production, resulting in total production that declines approximately 0% to 5% compared to 2015, after adjusting for asset sales. At February 23, 2016, the company had approximately $700 million in asset divestitures that had closed or that signed and are expected to close between now and the end of the 2016 second quarter. The company expects that these asset sales will result in lower production of approximately 31,000 barrels of oil equivalent (boe) per day of production in 2016. The planned divestiture of certain of the company's Granite Wash assets in Western Oklahoma and the Texas Panhandle requires Chesapeake to repurchase the overriding royalty interests related to three of the company's previous volumetric production payment transactions for approximately $200 million. As a result, the projected net impact to the company's full year 2016 production will be a reduction of approximately 25,000 boe per day.

In addition, to help improve the company's cash flow and provide protection against lower commodity prices, Chesapeake has hedged more than 590 billion cubic feet of its projected 2016 natural gas production at approximately $2.84 per mcf and more than 19 million barrels of its projected 2016 oil production at approximately $47.79 per barrel. A summary of the company's planned 2016 capital program is shown below in the "Capital Spending and Cost Overview" section, while the company's 2016 forecasted production volumes are provided in the Outlook dated February 24, 2016.

2015 Full Year Results

For the 2015 full year, Chesapeake reported a net loss available to common stockholders of $14.856 billion, or $22.43 per fully diluted share. Items typically excluded by securities analysts in their earnings estimates reduced net income available to common stockholders for the 2015 full year by approximately $14.527 billion. The primary sources of this reduction were quarterly noncash impairments of the carrying value of Chesapeake's oil and natural gas properties largely resulting from significant decreases in the trailing 12-month average first-day-of-the-month oil and natural gas prices used in the company's impairment calculations. Adjusting for these items, 2015 full year adjusted net loss available to common stockholders was $329 million, or $0.20 per fully diluted share, compared to adjusted net income available to common stockholders of $957 million, or $1.49 per fully diluted share, for the 2014 full year.

Adjusted ebitda was $2.385 billion for the 2015 full year, compared to $4.945 billion for the 2014 full year. Operating cash flow, which is defined as cash flow provided by operating activities before changes in assets and liabilities, was $2.268 billion for the 2015 full year, compared to $5.146 billion for the 2014 full year. The year-over-year decreases in adjusted ebitda and operating cash flow were primarily the result of lower realized oil, natural gas and natural gas liquid (NGL) prices and lower production volumes, partially offset by higher realized hedging gains and lower production expenses, general and administrative (G&A) expenses and production taxes. Realized hedging gains on the company's oil and gas production resulted in additional revenues of approximately $1.3 billion for the 2015 full year, on a pre-tax basis, compared to realized hedging losses of approximately $375 million for the 2014 full year.

Adjusted net income available to common stockholders, operating cash flow, ebitda and adjusted ebitda are non-GAAP financial measures. Reconciliations of these measures to comparable financial measures calculated in accordance with generally accepted accounting principles are provided in this release.

Chesapeake's daily production for the 2015 full year averaged 679,200 barrels of oil equivalent (boe), a year-over-year increase of 8%, adjusted for asset sales. Average daily production consisted of approximately 114,000 barrels (bbls) of oil, 2.9 billion cubic feet (bcf) of natural gas and 76,700 bbls of NGL. Adjusted for asset sales, 2015 full year average daily oil production increased 7%, average daily natural gas production increased 7% and average daily NGL production increased 14%.

2015 Fourth Quarter Financial Results

For the 2015 fourth quarter, Chesapeake reported a net loss available to common stockholders of $2.228 billion, or $3.36 per fully diluted share. Items typically excluded by securities analysts in their earnings estimates reduced 2015 fourth quarter net income by approximately $2.060 billion. The primary source of this reduction was a noncash impairment of the carrying value of Chesapeake's oil and natural gas properties largely resulting from significant decreases in the trailing 12-month average first-day-of-the-month oil and natural gas prices as of December 31, 2015, compared to September 30, 2015. Adjusting for these items, the 2015 fourth quarter net loss available to common stockholders was $168 million, or $0.16 per fully diluted share, which compares to adjusted net income available to common stockholders of $34 million, or $0.11 per fully diluted share, in the 2014 fourth quarter.

Adjusted ebitda was $298 million in the 2015 fourth quarter, compared to $916 million in the 2014 fourth quarter. Operating cash flow was $386 million in the 2015 fourth quarter, compared to $993 million in the 2014 fourth quarter. The year-over-year decreases in adjusted ebitda and operating cash flow were primarily the result of lower realized oil, natural gas and NGL prices and lower production volumes, partially offset by higher realized hedging gains and lower production expenses, G&A expenses and production taxes. Realized hedging gains on the company's oil and gas production resulted in additional revenues of approximately $334 million for the 2015 fourth quarter, on a pre-tax basis, compared to realized hedging gains of approximately $133 million for the 2014 fourth quarter.

Adjusted net income available to common stockholders, operating cash flow, ebitda and adjusted ebitda are non-GAAP financial measures. Reconciliations of these measures to comparable financial measures calculated in accordance with generally accepted accounting principles are provided in this release.

Chesapeake's daily production for the 2015 fourth quarter averaged approximately 661,100 boe, a year-over-year increase of 1% adjusted for asset sales. Average daily production in the 2015 fourth quarter consisted of approximately 100,700 bbls of oil, 2.9 bcf of natural gas and 75,600 bbls of NGL. Adjusted for asset sales, 2015 fourth quarter average daily oil production decreased 7%, average daily natural gas production increased 3% and average daily NGL production increased 4%.

Capital Spending and Cost Overview

Chesapeake's drilling and completion capital expenditures during the 2015 full year were approximately $3.0 billion, and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property, plant and equipment were approximately $231 million, for a total of approximately $3.2 billion, within the company's forecasted range of $3.0 to $3.5 billion. Total capital expenditures, including capitalized interest of $424 million, were approximately $3.6 billion, compared to $6.7 billion in 2014, and are reconciled below. Chesapeake's total capital expenditures, including capitalized interest of $88 million, were approximately $548 million in the 2015 fourth quarter compared to approximately $1.8 billion in the 2014 fourth quarter.

	2014		2015		2016
Activity Comparison	Q4	FY	Q4	FY	Outlook
Average operated rig count	67	64	14	28	4 - 7
Gross wells completed	341	1,169	85	547	280 - 350
Gross wells spud	308	1,173	66	499	85 - 125
Gross wells connected	311	1,148	100	650	330 - 370
Type of Cost ($ in millions)					
Drilling and completion costs	$ 1,370	$ 4,470	$ 405	$ 2,959	$800 - 1,300
Other exploration and development costs and PP&E	252	669	55	231	200
Subtotal capital expenditures	$ 1,622	$ 5,139	$ 460	$ 3,190	$1,000 - 1,500
Capitalized interest	134	637	88	424	300
PRB property exchange	—	450	—	—	—
Sale leasebacks	25	499	—	—	—
Total capital expenditures	$ 1,781	$ 6,725	$ 548	$ 3,614	$1,300 - 1,800

Chesapeake's focus on cost discipline continued to generate reductions in production and G&A expenses. Production expenses during the 2015 full year were $4.22 per boe, while G&A expenses (including stock-based compensation) during the 2015 full year were $0.95 per boe. Combined production expenses and G&A expenses (including stock-based compensation) during the 2015 full year decreased 13% compared to the 2014 full year.

Average production expenses during the 2015 fourth quarter were $3.62 per boe, a decrease of 29% from the 2014 fourth quarter. G&A expenses (including stock-based compensation) during the 2015 fourth quarter were $1.02 per boe, a decrease of 26% from the 2014 fourth quarter. A summary of the company's guidance for 2016 is provided in the Outlook dated February 24, 2016.

Balance Sheet and Liquidity

Chesapeake made significant debt reductions in 2015, with total principal debt balances down to approximately $9.7 billion at year-end 2015 compared to approximately $11.8 billion at year-end 2014. In November 2015, the company repurchased $394 million of its 2.75% cumulative convertible senior notes due 2035. In December 2015, the company privately exchanged new 8.00% senior secured second lien notes due 2022 (second lien notes) for certain outstanding senior unsecured notes (existing notes). Approximately $3.9 billion of the existing notes were validly tendered in exchange for approximately $2.4 billion of the second lien notes. In addition, since September 30, 2015, the company has repurchased, for cash, approximately $240 million of 3.25% senior notes due March 2016 at an average discount of approximately 5% and approximately $60 million of debt due in 2017 (including convertible debt) at an average discount of approximately 45%.

As of February 23, 2016, Chesapeake's debt principal balance was approximately $9.5 billion, and the company's near-term liquidity consisted of over $300 million in cash and a $4 billion revolving credit facility, which was undrawn (other than letters of credit issued thereunder with the aggregate face amount of approximately $77 million). The company plans to repay the remaining balance of its 3.25% senior notes due March 2016 with available liquidity and expects to continue to take advantage of the significant discounts in the prices of its debt securities in 2016.

Midstream Transportation Update

In February 2016, Chesapeake amended certain of its firm transportation agreements in its Haynesville, Barnett and Eagle Ford operating areas which reduced the company's firm transportation volume commitments and fees. The company estimates a benefit of approximately $50 million in lower unused demand charges for its underutilized capacity and lower transportation fees in 2016, which equates to an approximate $0.06 per mcf improvement in the company's total transportation expenses for natural gas. These benefits have been included in the company's cost guidance provided in the Outlook dated February 24, 2016. Chesapeake continues to seek to modify additional gathering, processing and transportation agreements with its midstream service providers resulting in mutually beneficial solutions in 2016.

Operational Results

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately 97 thousand barrels of oil equivalent (mboe) per day (210 gross operated mboe per day) during the 2015 fourth quarter, a decrease of 10% sequentially. Production during the 2015 fourth quarter was impacted by plant downtime that averaged 2 mboe per day. Average completed well costs to date in 2015 (through October) are $5.4 million with an average completed lateral length of 6,250 feet and 23 frac stages, compared to the full-year 2014 average completed well cost of $5.9 million with an average completed lateral length of 5,850 feet and 18 frac stages. The company placed 18 wells on production during the 2015 fourth quarter, compared to 123 wells in the 2014 fourth quarter, and plans to place approximately 170 to 180 wells on production in 2016. Chesapeake's operated rig count in the Eagle Ford averaged three rigs in the 2015 fourth quarter, and the company anticipates releasing all operated rigs in the area by June.

Haynesville and Bossier Shales (Northwest Louisiana): Haynesville net production averaged approximately 609 million cubic feet of natural gas (mmcf) per day (972 gross operated mmcf per day) during the 2015 fourth quarter, a decrease of 4% sequentially. Average completed well costs to date in 2015 (through October) are $7.7 million with an average completed lateral length of 5,350 feet and 17 frac stages, compared to the full-year 2014 average completed well cost of $8.4 million with an average completed lateral length of 4,900 feet and 14 frac stages. Longer completed laterals continue to generate significant efficiencies with equivalent per foot of lateral production, evidenced by the company's first well in the area with a completed lateral length of more than 10,000 feet, the PE 36&25-15-15 1H ALT, which reached a peak rate of 25.0 mmcf per day with a flowing tubing pressure of 7,200 psi. The company placed 13 wells on production during the 2015 fourth quarter, compared to 18 wells in the 2014 fourth quarter, and plans to place approximately 50 to 60 wells on production in 2016. Operated rig count in the Haynesville averaged six rigs in the 2015 fourth quarter, and the company anticipates utilizing up to three operated rigs in the area in 2016.

Mid-Continent: Oklahoma STACK (Northwest and Central Oklahoma): The company has completed three wells targeting the Meramec formation with highly encouraging results. The first two wells, the Rouce 4-17-10 1H and Wittrock 16-16-9 1H, reached peak production of approximately 1,010 bbls of oil per day (1,260 boe per day) and 1,500 bbls of oil per day (2,240 boe per day), respectively. The company's third well, the Stangl 36-16-9 1H, has reached 1,241 bbls of oil per day (1,480 boe per day) after eight days of flowback. The company has also recently drilled two additional Oswego wells which are currently being completed and will likely be placed on production in the second quarter. The company plans to continue to delineate its significant STACK position and place approximately 35 to 45 wells on production and utilize up to three rigs in 2016.

Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 29 mboe per day (67 gross operated mboe per day) during the 2015 fourth quarter, a decrease of 7% sequentially. Average completed well costs to date in 2015 (through October) are $2.8 million with an average completed lateral length of 4,600 feet and 10 frac stages, compared to the full-year 2014 average completed well cost of $3.0 million with an average completed lateral length of 4,450 feet and nine frac stages. Chesapeake's first multilateral well in the Mississippian Lime, the Wilber 26-27-11 1H having dual laterals of 4,653 feet and 4,556 feet, reached a peak rate of 1,570 boe per day in the 2015 fourth quarter. The company placed 11 wells on production during the 2015 fourth quarter, compared to 42 wells in the 2014 fourth quarter. Operated rig count in the Mississippian Lime averaged one rig during the 2015 fourth quarter.

Utica Shale (Eastern Ohio): Utica net production averaged approximately 140 mboe per day (241 gross operated mboe per day) during the 2015 fourth quarter, an increase of 33% sequentially, as the company brought curtailed volumes to market as new transportation became available with better pricing. Average completed well costs to date in 2015 (through October) are $7.2 million with an average completed lateral length of 7,800 feet and 40 frac stages, compared to the full-year 2014 average completed well cost of $7.2 million with an average completed lateral length of 6,200 feet and 29 frac stages. The company placed 43 wells on production during the 2015 fourth quarter, compared to 51 wells in the 2014 fourth quarter, and plans to place approximately 45 to 55 wells on production in 2016. Operated rig count in the Utica averaged two rigs in the 2015 fourth quarter. The company has now released all operated rigs in the area.

Marcellus Shale (Northern Pennsylvania): Marcellus net production averaged approximately 782 mmcf per day (1.78 gross operated bcf per day) during the 2015 fourth quarter, a decrease of 3% sequentially. Average completed well costs to date in 2015 (through October) are $7.6 million with an average completed lateral length of 6,750 feet and 29 frac stages, compared to the full-year 2014 average completed well cost of $7.5 million with an average completed lateral length of 6,000 feet and 27 frac stages. The company placed three wells on production during the 2015 fourth quarter, compared to 25 wells in the 2014 fourth quarter, and plans to place approximately 20 wells on production in 2016. Operated rig count in the Marcellus averaged one rig in the 2015 fourth quarter. The company has now released all operated rigs in the area.

Powder River Basin (PRB) (Wyoming): PRB net production averaged approximately 20 mboe per day (30 gross operated mboe per day) during the 2015 fourth quarter, a decrease of 4% sequentially. Average completed well costs to date in 2015 (though October) are $10.4 million with an average completed lateral length of 5,900 feet and 22 frac stages, compared to the full-year 2014 average completed well cost of $10.6 million with an average completed lateral length of 5,400 feet and 20 frac stages. The company placed seven wells on production during the 2015 fourth quarter, compared to 13 wells in the 2014 fourth quarter, and plans to place approximately five wells on production in 2016. The company has released all operated rigs in the area.

Key Financial and Operational Results

The table below summarizes Chesapeake's key financial and operational results during the 2015 fourth quarter and 2015 full year, as compared to results in prior periods.

	Three Months Ended			Full Year Ended	
	12/31/15	09/30/15	12/31/14	12/31/15	12/31/14
Oil equivalent production (in mmboe)	61	61	67	248	258
Oil production (in mmbbls)	9	11	11	42	42
Average realized oil price ($/bbl)[a]	64.04	66.04	79.02	66.91	85.04
Oil as % of total production	15	17	17	17	16
Natural gas production (in bcf)	268	263	282	1,070	1,095
Average realized natural gas price ($/mcf)[a]	2.35	2.51	3.58	2.72	3.97
Natural gas as % of total production	74	72	70	72	71
NGL production (in mmbbls)	7	7	9	28	33
Average realized NGL price ($/bbl)[a]	14.07	10.90	22.60	14.06	30.95
NGL as % of total production	11	11	13	11	13
Production expenses ($/boe)	(3.62)	(4.09)	(5.07)	(4.22)	(4.69)
Gathering, processing and transportation expenses[b]	(11.34)	(7.88)	(9.53)	(8.55)	(8.43)
Production taxes ($/boe)	(0.19)	(0.42)	(0.70)	(0.40)	(0.90)
General and administrative expenses ($/boe)[c]	(0.84)	(0.64)	(1.23)	(0.77)	(1.07)
Stock-based compensation ($/boe)	(0.18)	(0.14)	(0.15)	(0.18)	(0.18)
DD&A of oil and natural gas properties ($/boe)	(5.37)	(7.95)	(10.53)	(8.47)	(10.41)
DD&A of other assets ($/boe)	(0.50)	(0.51)	(0.56)	(0.53)	(0.90)
Interest expenses ($/boe)[a]	(1.70)	(1.41)	(0.56)	(1.30)	(0.63)
Marketing, gathering and compression net margin ($ in millions)[d]	2	58	(39)	243	(11)
Oilfield services net margin ($ in millions)[e]	—	—	—	—	115
Operating cash flow ($ in millions)[f]	386	476	993	2,268	5,146
Operating cash flow ($/boe)	6.35	7.76	14.81	9.15	19.96
Adjusted ebitda ($ in millions)[g]	298	560	916	2,385	4,945
Adjusted ebitda ($/boe)	4.90	9.12	13.66	9.62	19.18
Net income (loss) available to common stockholders ($ in millions)	(2,228)	(4,695)	586	(14,856)	1,273
Earnings (loss) per share – diluted ($)	(3.36)	(7.08)	0.81	(22.43)	1.87
Adjusted net income (loss) available to common stockholders ($ in millions)[h]	(168)	(83)	34	(329)	957
Adjusted earnings (loss) per share – diluted ($)	(0.16)	(0.05)	0.11	(0.20)	1.49

(a) Includes the effects of realized gains (losses) from hedging, but excludes the effects of unrealized gains (losses) from hedging.

(b) We have revised our presentation of third-party oil, natural gas and NGL gathering, processing and transportation costs to report the costs as a component of operating expenses in the statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. Includes $2.81/boe and $1.79/boe for minimum volume commitment (MVC) shortfall payments for the three months ended December 31, 2015, and December 31, 2014, respectively, and $0.69/boe and $0.46/boe for MVC shortfall payments for the full year ended December 31, 2015 and December 31, 2014, respectively.

(c) Excludes expenses associated with stock-based compensation and restructuring [illegible]

(d) Includes revenue, operating expenses and [illegible]

(e) Includes revenue [illegible]

(f) Defined as operating [illegible]

(g) Defined as [illegible]

(h) Defined as [illegible]

[illegible] December 31, 2015, September 30, 2015 and December 31, 2014, respectively, and $296 million and $3 million for the year ended December 31, 2015 and 2014, respectively. Excludes depreciation and amortization of other assets.

2015 Fourth Quarter and Year-End Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled on Wednesday, February 24, 2016, at 9:00 am EST. The telephone number to access the conference call is 785-424-1666 or toll-free 877-876-9177. The passcode for the call is 7678649. The number to access the conference call replay is 719-457-0820 or toll-free 888-203-1112 and the passcode for the replay is 7678649. The conference call will also be webcast live at www.chk.com in the "Investors" section of the company's website. The webcast of the conference will be available on the website for one year.

Chesapeake Energy Corp. (NYSE:CHK) is the second-largest producer of natural gas and the 14th largest producer of oil in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing its large and geographically diverse resource base of unconventional oil and natural gas assets onshore in the U.S. The company also owns substantial marketing and compression businesses. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and news releases.

This news release 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 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 noncore 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 (including our ability to optimize base production and execute gas gathering agreements), 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 the volatility of oil, natural gas and NGL prices; write-downs of our oil and natural gas carrying values due to declines in prices; the limitations our level of indebtedness may have on our financial flexibility; the availability of operating cash flow and other funds to finance reserve replacement costs; 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 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; federal and state tax proposals affecting our industry; potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations; impacts of potential legislative and regulatory actions addressing climate change; 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; cyber attacks adversely impacting our operations; and 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. 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 news release, and we undertake no obligation to update any of the information provided in this release or the accompanying Outlook, except as required by applicable law.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

($ in millions, except per share data)

(unaudited)

	Three Months Ended December 31,		Years Ended December 31,	
	2015	2014	2015	2014
REVENUES:				
Oil, natural gas and NGL	$ 1,269	$ 3,008	$ 5,391	$ 10,354
Marketing, gathering and compression	1,380	2,681	7,373	12,225
Oilfield services	—	—	—	546
Total Revenues	2,649	5,689	12,764	23,125
OPERATING EXPENSES:				
Oil, natural gas and NGL production	220	340	1,046	1,208
Oil, natural gas and NGL gathering, processing and transportation	690	639	2,119	2,174
Production taxes	12	47	99	232
Marketing, gathering and compression	1,378	2,720	7,130	12,236
Oilfield services	—	—	—	431
General and administrative	62	93	235	322
Restructuring and other termination costs	(3)	(5)	36	7
Provision for legal contingencies	(6)	134	353	234
Oil, natural gas and NGL depreciation, depletion and amortization	326	706	2,099	2,683
Depreciation and amortization of other assets	30	38	130	232
Impairment of oil and natural gas properties	2,831	—	18,238	—
Impairments of fixed assets and other	27	14	194	88
Net (gains) losses on sales of fixed assets	1	3	4	(199)
Total Operating Expenses	5,568	4,729	31,683	19,648
INCOME (LOSS) FROM OPERATIONS	(2,919)	960	(18,919)	3,477
OTHER INCOME (EXPENSE):				
Interest expense	(107)	(7)	(317)	(89)
Losses on investments	(39)	(7)	(96)	(75)
Impairments of investments	(53)	—	(53)	(5)
Net gain on sales of investments	—	—	—	67
Gains (losses) on purchases or exchanges of debt	279	(2)	279	(197)
Other income	5	10	8	22
Total Other Income (Expense)				

INCOME (LOSS) BEFORE INCOME TAXES	(2,834)	954	(19,098)	3,200
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	(30)	13	(36)	47
Deferred income taxes	(619)	273	(4,427)	1,097
Total Income Tax Expense (Benefit)	(649)	286	(4,463)	1,144
NET INCOME (LOSS)	(2,185)	668	(14,635)	2,056
Net income attributable to noncontrolling interests	—	(29)	(50)	(139)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(2,185)	639	(14,685)	1,917
Preferred stock dividends	(43)	(43)	(171)	(171)
Repurchase of preferred shares of CHK Utica	—	—	—	(447)
Earnings allocated to participating securities	—	(10)	—	(26)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (2,228)	$ 586	$ (14,856)	$ 1,273
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (3.36)	$ 0.89	$ (22.43)	$ 1.93
Diluted	$ (3.36)	$ 0.81	$ (22.43)	$ 1.87
WEIGHTED AVERAGE COMMON AND COMMON				
EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	663	660	662	659
Diluted	663	773	662	772

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

($ in millions)

(unaudited)

	December 31, 2015	December 31, 2014
Cash and cash equivalents	$ 825	$ 4,108
Other current assets	1,655	3,360
Total Current Assets	2,480	7,468
Property and equipment, (net)	14,298	32,515
Other assets	579	768
Total Assets	$ 17,357	$ 40,751
Current liabilities	$ 3,685	$ 5,656
Long-term debt, net of discounts	10,354	11,154
Other long-term liabilities	921	1,344
Deferred income tax liabilities	—	4,392
Total Liabilities	14,960	22,546
Preferred stock	3,062	3,062
Noncontrolling interests	259	1,302
Common stock and other stockholders' equity	(924)	13,841
Total Equity	2,397	18,205
Total Liabilities and Equity	$ 17,357	$ 40,751
Common shares outstanding (in millions)	663	663
Principal amount of debt outstanding	$ 9,706	$ 11,756

CHESAPEAKE ENERGY CORPORATION

CAPITALIZATION

($ in millions)

(unaudited)

	December 31, 2015	Decemb
Total debt, net of unrestricted cash	$ 9,910	$ 7,42
Preferred stock	3,062	3,062
Noncontrolling interests[a]	259	1,302
Common stock and other stockholders' equity	(924)	13,841
Total	$ 12,307	$ 25,6
Total net debt to capitalization ratio	81%	29%

[a] Includes third-party ownership as follows:

Chesapeake Granite Wash Trust	$ 259	$ 287
CHK Cleveland Tonkawa, L.L.C. [1]	—	1,015
Total	$ 259	$ 1,30

[1] Repurchase of noncontrolling interest of CHK Cleveland Tonkawa, L.L.C. occurred in August 2015.

CHESAPEAKE ENERGY CORPORATION

ROLL-FORWARD OF PROVED RESERVES

YEAR ENDED DECEMBER 31, 2015

(unaudited)

	M
Beginning balance, December 31, 2014	2,
Production	(2
Acquisitions	&r
Divestitures	(6
Revisions - changes to previous estimates	21
Revisions - price	(1
Extensions and discoveries	23
Ending balance, December 31, 2015	1,
Proved reserves growth rate before acquisitions and divestitures	(3
Proved reserves growth rate after acquisitions and divestitures	(3
Proved developed reserves	1,
Proved developed reserves percentage	84
PV-10 ($ in millions)[(a)]	$

(a) Reserve volumes and PV-10 value estimated using SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices as of December 31, 2015 of $50.28 per bbl of oil and $2.58 per mcf of natural gas, before basis differential adjustments.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF PV-10

($ in millions)

(unaudited)

	December 31, 2015	December 31, 2014
Standardized measure of discounted future net cash flows	$ 4,693	$ 17,133
Discounted future cash flows for income taxes	34	4,879
Discounted future net cash flows before income taxes (PV-10)	$ 4,727	$ 22,012

PV-10 is discounted (at 10%) future net cash flows before income taxes. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and is calculated in accordance with Accounting Standards Codification Topic 932. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependent on the unique tax situation of each individual company.

The company's PV-10 and standardized measure were calculated using the following prices, before basis differential adjustments: $50.28 per bbl of oil and $2.58 per mcf of natural gas as of December 31, 2015, and $94.98 per bbl of oil and $4.35 per mcf of natural gas as of December 31, 2014.

CHESAPEAKE ENERGY CORPORATION

SUPPLEMENTAL DATA – OIL, NATURAL GAS AND NGL PRODUCTION, SALES AND INTEREST EXPENSE

(unaudited)

	Three Months Ended December 31,		Years Ended December 31,	
	2015	2014	2015	2014
Net Production:				
Oil (mmbbl)	9	11	42	42
Natural gas (bcf)	268	282	1,070	1,095
NGL (mmbbl)	7	9	28	33
Oil equivalent (mmboe)	61	67	248	258
Oil, natural gas and NGL Sales ($ in millions): [a]				
Oil sales	$ 355	$ 778	$ 1,904	$ 3,778
Oil derivatives – realized gains (losses)[b]	238	103	880	(185)
Oil derivatives – unrealized gains (losses)[b]	(92)	505	(536)	859
Total Oil Sales				

1,386

Natural gas sales	533	978	2,470	4,535
Natural gas derivatives – realized gains (losses)[b]	96	30	437	(191)
Natural gas derivatives – unrealized gains (losses)[b]	41	411	(157)	535
Total Natural Gas Sales	670	1,419	2,750	4,879
NGL sales	98	203	393	1,023
Total NGL Sales	98	203	393	1,023
Total Oil, Natural Gas and NGL Sales	$ 1,269	$ 3,008	$ 5,391	$ 10,354
Average Sales Price – excluding gains (losses) on derivatives:				
Oil ($ per bbl)	$ 38.33	$ 69.78	$ 45.77	$ 89.41
Natural gas ($ per mcf)	$ 1.99	$ 3.47	$ 2.31	$ 4.14
NGL ($ per bbl)	$ 14.07	$ 22.60	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 16.20	$ 29.21	$ 19.23	$ 36.21
Average Sales Price – including realized gains (losses) on derivatives:				
Oil ($ per bbl)	$ 64.04	$ 79.02	$ 66.91	$ 85.04
Natural gas ($ per mcf)	$ 2.35	$ 3.58	$ 2.72	$ 3.97
NGL ($ per bbl)	$ 14.07	$ 22.60	$ 14.06	$ 30.95
Oil equivalent ($ per boe)	$ 21.70	$ 31.20	$ 24.54	$ 34.74
Interest Expense ($ in millions):				
Interest[c]	$ 107	$ 40	$ 329	$ 173
Derivatives – realized (gains) losses[d]	(2)	(2)	(6)	(12)
Derivatives – unrealized (gains) losses[d]	2	(31)	(6)	(72)
Total Interest Expense	$ 107	$ 7	$ 317	$ 89

(a) We have revised our presentation of third-party oil, natural gas and NGL gathering, processing and transportation costs to repor the costs as a component of operating expenses in the statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales.

(b) Realized gains and losses include the following items: (i) settlements of nondesignated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains and losses related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains and losses include the change in fair value of open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains and losses during the period. Although we no longer designate our derivatives as cash flow hedges for accounting purposes, we believe these definitions are useful to management and investors in determining the effectiveness of our price risk management program.

(c) Net of amounts capitalized.

(d) Realized (gains) losses include settlements related to the current period interest accrual and the effect of (gains) losses on early termination trades. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	December 31, 2015	December 31, 2014
Beginning cash	$ 1,759	$ 90
Net cash provided by operating activities	179	829
Cash flows from investing activities:		
Drilling and completion costs[a]	(399)	(1,396)
Acquisitions of proved and unproved properties[b]	(126)	(288)
Proceeds from divestitures of proved and unproved properties	1	5,090
Additions to other property and equipment[c]	(29)	(26)
Cash paid to purchase leased rigs and compressors	—	(25)
Proceeds from sales of other property and equipment	9	39
Additions to investments	(2)	(3)
Other	—	1
Net cash provided by (used in) investing activities	(546)	3,392
Net cash used in financing activities	(567)	(203)
Change in cash and cash equivalents	(934)	4,018
Ending cash	$ 825	$ 4,108

(a) Includes capitalized interest of $2 million and $11 million for the three months ended December 31, 2015 and 2014, respectively.

(b) Includes capitalized interest of $81 million and $120 million for the three months ended December 31, 2015 and 2014, respectively.

(c) Includes capitalized interest of $4 million and $3 million for the three months ended December 31, 2015 and 2014, respectively.

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

YEAR ENDED:	December 31, 2015	December 31, 2014
Beginning cash	$ 4,108	$ 837
Net cash provided by operating activities	1,234	4,634
Cash flows from investing activities:		
Drilling and completion costs[a]	(3,095)	(4,581)
Acquisitions of proved and unproved properties[b]	(533)	(1,311)
Proceeds from divestitures of proved and unproved properties	189	5,813
Additions to other property and equipment[c]	(143)	(227)
Cash paid to purchase leased rigs and compressors	—	(499)
Proceeds from sales of other property and equipment	89	1,003
Additions to investments	(10)	(17)
Proceeds from sales of investments	—	239
Decrease in restricted cash	52	37
Other	—	(3)
Net cash provided by (used in) investing activities	(3,451)	454
Net cash used in financing activities	(1,066)	(1,817)
Change in cash and cash equivalents	(3,283)	3,271
Ending cash	$ 825	$ 4,108

(a) Includes capitalized interest of $24 million and $50 million for the years ended December 31, 2015 and 2014, respectively.

(b) Includes capitalized interest of $387 million and $553 million for the years ended December 31, 2015 and 2014, respectively.

(c) Includes capitalized interest of $14 million and $33 million for the years ended December 31, 2015 and 2014, respectively.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per share data)

(unaudited)

THREE MONTHS ENDED:	December 31, 2015	September 30, 2015	December 30, 2014
Net income (loss) available to common stockholders	$ (2,228)	$ (4,695)	$ 586
Adjustments, net of tax:			
Unrealized (gains) losses on commodity derivatives	41	58	(663)
Unrealized gains on supply contract derivatives	(4)	(58)	(2)
Restructuring and other termination costs	(2)	44	(3)
Provision for legal contingencies	(5)	—	94
Impairment of oil and natural gas properties	2,183	4,506	—
Impairments of fixed assets and other	21	66	10
Net (gains) losses on sales of fixed assets	1	(1)	2
Impairment of investments	41	—	—
(Gains) losses on purchases or exchanges of debt	(215)	—	2
Other	(1)	(3)	8
Adjusted net income (loss) available to common stockholders[a]	$ (168)	$ (83)	$ 34
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	—	—	10
Total adjusted net income (loss) attributable to Chesapeake	$ (125)	$ (40)	$ 87
Weighted average fully diluted shares outstanding	777	777	775
(in millions)[b]			
Adjusted earnings (loss) per share assuming dilution[a]	$ (0.16)	$ (0.05)	$ 0.11

(a) Adjusted net income and adjusted earnings per share assuming dilution 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 available to common stockholders or diluted earnings per share. Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution 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 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 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.

(b) Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS

($ in millions, except per share data)

(unaudited)

YEAR ENDED:	December 31, 2015	December 30, 2014
Net income (loss) available to common stockholders	$ (14,856)	$ 1,273
Adjustments, net of tax:		
Unrealized (gains) losses on commodity derivatives	527	(941)
Unrealized gains on supply contract derivatives	(226)	(2)
Restructuring and other termination costs	28	4
Provision for legal contingencies	270	150
Impairment of oil and natural gas properties	13,976	—
Impairments of fixed assets and other	148	57
Net (gains) losses on sales of fixed assets	3	(128)
Impairments of investments	41	3
Net gain on sales of investments	—	(43)
(Gains) losses on purchases or exchanges of debt	(214)	126
Repurchase of preferred shares of CHK Utica	—	447
Tax rate adjustment	(17)	—
Other	(9)	11
Adjusted net income (loss) available to common stockholders[a]	$ (329)	$ 957
Preferred stock dividends	171	171
Earnings allocated to participating securities	—	26
Total adjusted net income (loss) attributable to Chesapeake	$ (158)	$ 1,154
Weighted average fully diluted shares outstanding (in millions)[b]	777	776
Adjusted earnings (loss) per share assuming dilution[a]	$ (0.20)	$ 1.49

(a) Adjusted net income and adjusted earnings per share assuming dilution 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 available to common stockholders or diluted earnings per share. Adjusted net income available to common stockholders and adjusted earnings per share assuming dilution 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 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 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.

(b) Weighted average fully diluted shares outstanding include shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	December 31, 2015	September 30, 2015	December 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 179	$ 318	$ 829
Changes in assets and liabilities	207	158	164
OPERATING CASH FLOW[(a)]	$ 386	$ 476	$ 993

THREE MONTHS ENDED:	December 31, 2015	September 30, 2015	December 30, 2014
NET INCOME (LOSS)	$ (2,185)	$ (4,639)	$ 668
Interest expense	107	88	7
Income tax expense (benefit)	(649)	(937)	286
Depreciation and amortization of other assets	30	31	38
Oil, natural gas and NGL depreciation, depletion and amortization	326	488	706
EBITDA[(b)]			

$

(4,969)

$

1,705

THREE MONTHS ENDED:	December 31, 2015	September 30, 2015	December 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 179	$ 318	$ 829
Changes in assets and liabilities	207	158	164
Interest expense, net of unrealized gains (losses) on derivatives	104	86	38
Gains on commodity derivatives, net	284	227	1,049
Gains on supply contract derivatives, net	5	70	3
Cash receipts on oil, natural gas and NGL derivative settlements, net	(273)	(223)	(88)
Stock-based compensation	(17)	(18)	—
Restructuring and other termination costs	3	(53)	(3)
Provision for legal contingencies	19	—	(134)
Impairment of oil and natural gas properties	(2,831)	(5,416)	—
Impairments of fixed assets and other	(16)	(78)	(14)
Net gains (losses) on sales of fixed assets	(1)	1	(2)
Losses on investments	(39)	(33)	(7)
Impairment of investments	(53)	—	—
Gains (losses) on purchases or exchanges of debt	304	—	(2)
Other items	(246)	(8)	(128)
EBITDA[b]	$ (2,371)	$ (4,969)	$ 1,705

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under GAAP. Operating cash flow is widely accepted as a financial indicator of an oil and natural gas company's ability to generate cash that is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the oil and natural gas exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(b) Ebitda represents net income before interest expense, income taxes, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investmen recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported t our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it 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.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

YEAR ENDED:	December 31, 2015	December 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,234	$ 4,634
Changes in assets and liabilities	1,034	512
OPERATING CASH FLOW[a]	$ 2,268	$ 5,146

YEAR ENDED:	December 31, 2015	December 30, 2014
NET INCOME (LOSS)	$ (14,635)	$ 2,056
Interest expense	317	89
Income tax expense (benefit)	(4,463)	1,144
Depreciation and amortization of other assets	130	232
Oil, natural gas and NGL depreciation, depletion and amortization	2,099	2,683
EBITDA[b]	$ (16,552)	$ 6,204

YEAR ENDED:	December 31, 2015	December 30, 2014
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,234	$ 4,634
Changes in assets and liabilities	1,034	512
Interest expense, net of unrealized gains (losses) on derivatives	321	161
Gains on commodity derivatives, net	624	1,018
Gains on supply contract derivatives, net	295	3
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(1,132)	264
Stock-based compensation	(78)	(59)
Restructuring and other termination benefits	14	15
Provision for legal contingencies	(340)	(234)
Impairment of oil and natural gas properties	(18,238)	—
Impairments of fixed assets and other	(175)	(58)
Net gains (losses) on sales of fixed assets	(4)	199
Losses on investments	(96)	(75)
Impairments of investments	(53)	(5)
Net gain on sales of investments	—	67
Gains (losses) on purchases or exchanges of debt	304	(63)
Other items	(262)	(175)
EBITDA[b]	$ (16,552)	$ 6,204

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under GAAP. Operating cash flow is widely accepted as a financial indicator of an oil and natural gas company's ability to generate cash that is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the oil and natural gas exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

(b) Ebitda represents net income before interest expense, income taxes, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investmen recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported t our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements. Ebitda is not a measure of financial performance under GAAP. Accordingly, it 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.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	December 31, 2015	September 30, 2015	December 30, 2014
EBITDA	$ (2,371)	$ (4,969)	$ 1,705
Adjustments:			
Unrealized (gains) losses on oil, natural gas and NGL derivatives	51	67	(916)
Unrealized gains on supply contract derivatives	(5)	(70)	(3)
Restructuring and other termination costs	(3)	53	(5)
Provision for legal contingencies	(6)	—	134
Impairment of oil and natural gas properties	2,831	5,416	—
Impairments of fixed assets and other	27	79	14
Net (gains) losses on sales of fixed assets	1	(1)	3
Impairment of investments	53	—	—
(Gains) losses on purchases or exchanges of debt	(279)	—	2
Net income attributable to noncontrolling interests	—	(13)	(29)
Other	(1)	(2)	11
Adjusted EBITDA[a]	$ 298	$ 560	$ 916

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED EBITDA

($ in millions)

(unaudited)

YEAR ENDED:	December 31, 2015	December 30, 2014
EBITDA	$ (16,552)	$ 6,204
Adjustments:		
Unrealized (gains) losses on oil, natural gas and NGL derivatives	693	(1,394)
Unrealized gains on supply contract derivatives	(295)	(3)
Restructuring and other termination costs	36	7
Provision for legal contingencies	353	234
Impairment of oil and natural gas properties	18,238	—
Impairments of fixed assets and other	194	88
Net (gains) losses on sales of fixed assets	4	(199)
Impairments of investments	53	5
Net gains on sales of investments	—	(67)
(Gains) losses on purchases or exchanges of debt	(279)	197
Net income attributable to noncontrolling interests	(50)	(139)
Other	(10)	12
Adjusted EBITDA[a]	$ 2,385	$ 4,945

(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.

Chesapeake Energy Corp.
MANAGEMENT'S OUTLOOK AS OF FEBRUARY 24, 2016

Chesapeake periodically provides management guidance on certain factors that affect the company's future financial performance.

	Year Ending 12/31/2016
Adjusted Production Growth[(a)]	(5%) to (0%)
Absolute Production	
Liquids - mmbbls	55 - 59
Oil - mmbbls	34 - 36
NGL - mmbbls	21 - 23
Natural gas - bcf	1,000 - 1,040
Total absolute production - mmboe	222 - 232
Absolute daily rate - mboe	605 - 635
Estimated Realized Hedging Effects[(b)] (based on 2/22/16 strip prices):	
Oil - $/bbl	$7.01
Natural gas - $/mcf	$0.33
Estimated Basis to NYMEX Prices:	
Oil - $/bbl	$2.40 - $2.60
Natural gas - $/mcf	$0.30 - $0.40
NGL - $/bbl	$5.00 - $5.20
Operating Costs per Boe of Projected Production:	
Production expense	$3.60 - $3.80
Gathering, processing and transportation expenses	$7.75 - $8.25
Oil - $/bbl	$3.15 - $3.30
Natural Gas[(c)] - $/mcf	$1.45 - $1.55
NGL - $/bbl	$8.40 - $8.60
Production taxes	$0.35 - $0.45
General and administrative[(d)]	$0.60 - $0.70
Stock-based compensation (noncash)	$0.10 - $0.20
DD&A of natural gas and liquids assets	$3.50 - $4.50
Depreciation of other assets	$0.50 - $0.60
Interest expense[(e)]	$0.60 - $0.70
Marketing, gathering and compression net margin[(f)]	($20) - ($40)
Book Tax Rate	0%

Capital Expenditures ($ in millions)[g]	$1,000 - $1,500
Capitalized Interest ($ in millions)	$300
Total Capital Expenditures ($ in millions)	$1,300 - $1,800

(a) Based on 2015 production of 636 mboe per day, adjusted for 2015 sales.

(b) Includes expected settlements for commodity derivatives adjusted for option premiums. For derivatives closed early, settlements are reflected in the period of original contract expiration.

(c) Excludes the company's 2016 fourth quarter minimum volume commitment (MVC) shortfall estimate of approximately $165 to $175 million.

(d) Excludes expenses associated with stock-based compensation.

(e) Excludes unrealized gains (losses) on interest rate derivatives.

(f) Includes revenue and operating expenses. Excludes depreciation and amortization of other assets and unrealized gains (losses) on supply contract derivatives.

(g) Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs, rig termination payments and other property and plant and equipment and excludes approximately $200 million for the expected repurchase of overriding royalty interests associated with the expected sale of certain of the company's Granite Wash properties.

Oil and Natural Gas Hedging Activities

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse changes in market prices. Please see the quarterly reports on Form 10-Q and annual reports on Form 10-K filed by Chesapeake with the SEC for detailed information about derivative instruments the company uses, its quarter-end derivative positions and accounting for oil and natural gas derivatives.

As of February 23, 2016, the company had downside protection, through open swaps, on approximately 56% of its projected 2016 oil production at an average price of $47.79 per bbl. In addition, the company had downside price protection, through open swaps, on approximately 58% of the company's projected 2016 natural gas production at an average price of $2.84 per mcf.

The company's crude oil hedging positions as of February 23, 2016 were as follows:

Open Crude Oil Swaps; Gains from Closed

Crude Oil Trades and Call Option Premiums

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps		Tota and Call ($ in
Q1 2016	4,552	$	48.18	$
Q2 2016	5,187	$	47.42	$
Q3 2016	4,876	$	47.65	$
Q4 2016	4,876	$	47.97	$
Total 2016 [a]	19,491	$	47.79	$
Total 2017 – 2022	1,095	$	42.38	$

(a) Certain hedging arrangements include a sold option to extend at an average price of $53.67 per bbl cover
Sold options are included with net written call options.

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price	
Q1 2016	3,451	$	87.25
Q2 2016	3,451	$	87.25
Q3 2016	3,489	$	87.25
Q4 2016	3,488	$	87.25
Total 2016	13,879	$	87.25
Total 2017	5,293	$	83.50

The company's natural gas hedging positions as of February 23, 2016 were as follows:

Open Natural Gas Swaps; Gains (Losses) from Closed

Natural Gas Trades and Call Option Premiums

	Open Swaps (bcf)	Avg. NYMEX Price of Open Swaps	Total Losses from Closed Tr and Premiums Call Options ($ in millions)
Q1 2016	162	$ 3.06	$ (27)
Q2 2016	157	$ 2.71	$ (26)
Q3 2016	151	$ 2.76	$ (26)
Q4 2016	123	$ 2.84	$ (28)
Total 2016 [(a)]	593	$ 2.84	$ (107)
Total 2017 – 2022	—	$ —	$ (78)

(a) Certain hedging arrangements include a sold option to extend at an average price of $2.80 per mmbtu cov
Sold options are included with net written call options.

Natural Gas Net Written Call Options

	Call Options (bcf)	Avg. NYME Strike Price
Q1 2016	45	$ 5.27
Q2 2016	45	$ 5.27
Q3 2016	46	$ 5.27
Q4 2016	46	$ 5.27
Total 2016	182	$ 5.27
Total 2017 – 2022	114	$ 10.92

Natural Gas Basis Protection Swaps

	Volume (bcf)	Avg. NYME plus/(minus
Q1 2016	18	$ 0.70
Q2 2016	5	$ (0.48)
Q3 2016	5	$ (0.47)
Q4 2016	5	$ (0.47)
Total 2016	33	$ 0.17
Total 2017 - 2022		

(0.48)

INVESTOR CONTACT:
Brad Sylvester, CFA
(405) 935-8870
ir@chk.com

MEDIA CONTACT:
Gordon Pennoyer
(405) 935-8878
media@chk.com

SOURCE Chesapeake Energy Corp.