NEWS RELEASE

CHESAPEAKE ENERGY

Chesapeake Energy Corporation Reports 2015 First Quarter Financial and Operational Results

OKLAHOMA CITY--(BUSINESS WIRE)--May 6, 2015-- Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operational results for the 2015 first quarter. Highlights include:

- ***Average production of approximately 686,000 boe per day, an increase of 14% year over year, adjusted for asset sales***
- ***Adjusted net income of $0.11 per fully diluted share and adjusted ebitda of $928 million***
- ***2015 total production guidance increased to 640 – 650 mboe per day***
- ***2015 capital guidance of approximately $3.5 – $4.0 billion reiterated***
- ***Additional 600 – 700 new Eagle Ford locations added following successful down spacing test results***

Doug Lawler, Chesapeake’s Chief Executive Officer, commented, “Chesapeake is meeting the challenge of low commodity prices head-on and delivered a very strong first quarter. Adjusted for asset sales, our production in the 2015 first quarter grew by 14% compared to the 2014 first quarter. Our cash costs remain at industry-low levels and we expect our assets to continue delivering greater efficiencies even as we reduce our activity levels throughout 2015. We remain on target to balance our capital spending and our cash flow by year-end, and the capital efficiencies that we are seeing in each of our operating areas are helping to strengthen that cash flow. During this challenging commodity price environment, our talented employees and high-quality assets are delivering competitive, differential performance.”

2015 First Quarter Financial Results

For the 2015 first quarter, Chesapeake reported a net loss available to common stockholders of $3.782 billion, or ($5.72) per fully diluted share, which compares to net income available to common stockholders of $374 million, or $0.54 per fully diluted share in the 2014 first quarter. Items typically excluded by securities analysts in their earnings estimates reduced 2015 first quarter net income by approximately $3.824 billion on an after-tax basis and are presented on Page 11 of this release. The primary source of this reduction was an impairment in 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 March 31, 2015, compared to December 31, 2014. Adjusting for this and other items, 2015 first quarter net income available to common stockholders was $42 million, or $0.11 per fully diluted share, which compares to adjusted net income available to common stockholders of $405 million, or $0.59 per fully diluted share, in the 2014 first quarter.

Adjusted ebitda was $928 million in the 2015 first quarter, compared to $1.515 billion in the 2014 first quarter. Operating cash flow was $910 million in the 2015 first quarter, compared to $1.614 billion in the 2014 first quarter. 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.

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 on pages 11 – 13 of this release.

2015 First Quarter Average Daily Production of 686,000 Boe Increased 14% Year Over Year and 2% Sequentially, Adjusted for Asset Sales

Chesapeake's daily production for the 2015 first quarter averaged approximately 686,000 barrels of oil equivalent (boe), a year-over-year increase of 14%, adjusted for asset sales. Average daily production in the 2015 first quarter consisted of approximately 121,900 barrels (bbls) of oil, 2.9 billion cubic feet (bcf) of natural gas and 75,800 bbls of NGL, which represent year-over-year increases of 17%, 12% and 19%, respectively, adjusted for asset sales.

Capital Spending and Cost Overview

Chesapeake's drilling and completion capital expenditures during the 2015 first quarter were approximately $1.3 billion, and capital expenditures for leasehold, geological and geophysical costs and other property, plant and equipment were approximately $63 million, for a total of approximately $1.4 billion. Total capital expenditures, including capitalized interest of $123 million, were approximately $1.5 billion in the 2015 first quarter, compared to approximately $1.8 billion in the 2014 fourth quarter and $1.4 billion in the 2014 first quarter and are reconciled below.

Activity Comparison	**2015 Q1**	**2014 Q4**	**2014 Q1**
Average operated rig count	54	67	60
Gross wells completed	261	341	225
Gross wells spud	244	308	268
Gross wells connected	262	311	249
Type of Cost ($ in millions)			
Drilling and completion costs	$ 1,300	$ 1,370	$ 729
Leasehold, G&G and other PP&E	63	252	121
Subtotal capital spending	**$ 1,363**	**$ 1,622**	**$ 850**
Capitalized interest	123	134	178
Purchases of previously leased equipment	—	25	340
Total capital spending	**$ 1,486**	**$ 1,781**	**$ 1,368**

Chesapeake's focus on cost discipline continued to generate reductions in costs associated with production and general and administrative (G&A) expenses. Average production expenses during the 2015 first quarter were $4.84 per boe, a decrease of 5% from the 2014 fourth quarter and an increase of 2% year over year. G&A expenses (including stock-based compensation) during the 2015 first quarter were $0.91 per boe, a decrease of 34% from the 2014 fourth quarter and 30% year over year.

A summary of the company's guidance for 2015 is provided in the Outlook dated May 6, 2015, attached to this release as Schedule "A" beginning on Page 14.

Operational Results – Southern Division

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately 113 thousand barrels of oil equivalent (mboe) per day (242 gross operated mboe per day) during the 2015 first quarter, an increase of 7% sequentially. The full-year 2014 average completed well cost was $5.9 million with an average completed lateral length of 5,850 feet and 18 frac stages, compared to the full-year 2013 average completed well cost of $6.9 million with an average completed lateral length of 5,850 feet and 18 frac stages. Well cost-reduction efforts continue and the company anticipates completed well costs of $5.5 million by year-end 2015. The company has successfully drilled five wells with laterals in excess of 10,000 feet. This technical achievement will heavily influence future development in the field as the company prioritizes front-loading its drill schedule with this well design. Chesapeake has successfully completed down spacing tests in various sections of its acreage, adding 600 – 700 incremental locations to its undrilled inventory. The company plans to test its first Upper Eagle Ford well in the 2015 fourth quarter. The average peak production rate of the 105 wells that commenced first production in the Eagle Ford during the 2015 first quarter was approximately 763 boe per day.

Haynesville Shale and Bossier Shale (Northwest Louisiana): Haynesville net production averaged approximately 616 million cubic feet of natural gas equivalent (mmcf) per day (996 gross operated mmcf per day) during the 2015 first quarter, an increase of 4% sequentially. The full-year 2014 average completed well cost was $8.4 million with an average completed lateral length of 4,900 feet and 14 frac stages, compared to an average completed well cost of $8.9 million in 2013 with an average completed lateral length of 4,400 feet and 18 frac stages. In April 2015, the company placed its initial two modern extended lateral (7,500 feet) Haynesville wells on line, the Nguyen 8-15-14 1H ALT and the Nguyen 5-15-14 2H ALT at peak 24-hour rates of 18.5 mmcf per day and 16.7 mmcf per day, respectively, with flowing surface pressures of approximately 600 PSI per foot greater than surrounding in-unit wells. The average peak production rate of the 19 wells that commenced first production in the Haynesville during the 2015 first quarter was approximately 15.4 mmcf per day. Chesapeake also recently turned in line two successful tests in the Bossier Shale utilizing enhanced stimulation techniques. These wells are producing at a restricted rate of 12.0 mmcf per day paving the way for future Bossier development of 200 – 400 wells that can utilize both enhanced stimulation and extended laterals.

Mid-Continent North: Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 32 mboe per day (75 gross operated mboe per day) during the 2015 first quarter, an increase of 11% sequentially. The full-year 2014 average completed well cost was $3.0 million with an average completed lateral length of 4,500 feet, compared to an average completed well cost of $3.5 million in 2013 with an average completed lateral length of 4,500 feet. The company anticipates completed well costs of $2.5 million in 2015, resulting in a 45% capital reduction in three years. The average peak production rate of the 48 wells that commenced first production in the Mississippian Lime during the 2015 first quarter was approximately 733 boe per day.

Operational Results – Northern Division

Utica Shale (Eastern Ohio): Utica net production averaged approximately 110 mboe per day (190 gross operated mboe per day) during the 2015 first quarter, an increase of 10% sequentially. The full-year 2014 average completed well cost was $7.2 million with an average completed lateral length of 6,200 feet and 29 frac stages, compared to an average completed well cost of $6.7 million in 2013 with an average completed lateral length of 5,150 feet and 17 frac stages. Chesapeake anticipates average completed well costs of $8.2 million in 2015 while extending laterals to 7,900 feet with 41 frac stages. The average peak production rate of the 38 wells that commenced first production in the Utica during the 2015 first quarter was approximately 1,272 boe per day.

Marcellus Shale (Northern Pennsylvania): Marcellus net production averaged approximately 832 mmcf per day (1.932 gross operated bcf per day) during the 2015 first quarter, an increase of 2% sequentially. The 2014 full-year average completed well cost was $7.5 million with an average completed lateral length of 5,950 feet and 27 frac stages, compared to an average completed well cost of $7.9 million in 2013 with an average completed lateral length of 5,400 feet and 13 frac stages. With ample existing drilled inventory and significant curtailed volumes, Chesapeake expects to maintain production at current levels throughout 2015 in the Marcellus. The average peak production rate of the 16 wells that commenced first production in the northern Marcellus during the 2015 first quarter was approximately 15.8 mmcf per day.

Powder River Basin (PRB): Niobrara and Upper Cretaceous (Wyoming): PRB net production averaged approximately 20 mboe per day (30 gross operated mboe per day) during the 2015 first quarter, an increase of 10% sequentially. The 2014 full-year average completed well cost (including multiple exploratory wells) was $10.6 million per well with an average completed lateral length of 5,425 feet and 20 frac stages, compared to an average completed well cost of $10.1 million per well in 2013 with an average completed lateral length of 5,050 feet and 15 frac stages. Chesapeake continues to improve operational efficiency and has successfully tested multiple Upper Cretaceous test wells. The average peak production rate of the 11 wells that commenced first production in the PRB during the 2015 first quarter was approximately 1,594 boe per day.

Key Financial and Operational Results

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

	Three Months Ended		
	03/31/15	**12/31/14**	**03/31/14**
Oil equivalent production (in mmboe)	61.8	67.1	60.8
Oil production (in mmbbls)	11.0	11.2	9.9
Average realized oil price ($/bbl)[(a)]	62.57	76.40	85.08
Oil as % of total production	18	17	16
Natural gas production (in bcf)	263.8	281.6	260.0
Average realized natural gas price ($/mcf)[(a)]	2.37	1.72	3.27
Natural gas as % of total production	71	70	71
NGL production (in mmbbls)	6.8	9.0	7.6
Average realized NGL price ($/bbl)[(a)]	6.99	13.11	29.23
NGL as % of total production	11	13	13
Production expenses ($/boe)	(4.84)	(5.07)	(4.73)
Production taxes ($/boe)	(0.45)	(0.70)	(0.83)
General and administrative costs ($/boe)[(b)]	(0.72)	(1.23)	(1.09)
Stock-based compensation ($/boe)	(0.19)	(0.15)	(0.21)
DD&A of natural gas and liquids properties ($/boe)	(11.08)	(10.53)	(10.33)
DD&A of other assets ($/boe)	(0.57)	(0.56)	(1.29)
Interest expense ($/boe)[(a)]	(0.98)	(0.56)	(0.90)
Marketing, gathering and compression net margin ($ in millions)[(c)]	(25)	(39)	35
Oilfield services net margin ($ in millions)[(c)]	—	—	45
Operating cash flow ($ in millions)[(d)]	910	873	1,614
Operating cash flow ($/boe)	14.73	13.01	26.55
Adjusted ebitda ($ in millions)[(e)]	928	916	1,515
Adjusted ebitda ($/boe)	15.02	13.66	24.94
Net income (loss) available to common stockholders ($ in millions)	(3,782)	586	374
Earnings (loss) per share – diluted ($)	(5.72)	0.81	0.54

Adjusted net income available to common stockholders ($ in millions)[(f)]	42	34	405
Adjusted earnings per share – diluted ($)	0.11	0.11	0.59

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

(b) Excludes expenses associated with stock-based compensation and restructuring and other termination costs.

(c) Includes revenue and operating expenses and excludes depreciation and amortization of other assets.

(d) Defined as cash flow provided by operating activities before changes in assets and liabilities.

(e) Defined as net income before interest expense, income taxes and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on Page 13.

(f) Defined as net income available to common stockholders, as adjusted to remove the effects of certain items detailed on Page 11.

2015 First Quarter Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday, May 6, 2015, at 9:00 am EDT. The telephone number to access the conference call is **913-312-1393** or toll-free **888-797-2983**. The passcode for the call is **3887326**. We encourage those who would like to participate in the call to place calls between 8:50 and 9:00 am EDT. For those unable to participate in the live conference call, a replay will be available for audio playback at 2:00 pm EDT on Wednesday, May 6, 2015, and will run through 2:00 pm EDT on Wednesday, May 20, 2015. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **3887326**. The conference call will also be webcast live on Chesapeake's website at www.chk.com and a replay will be available following the call. An investor presentation has been posted on the company's website at www.chk.com/investors/presentations. The latest investor presentation that will be referenced during the call provides additional financial and operational disclosure and will be available in the Investor Relations section of the company's website.

Chesapeake Energy Corporation (NYSE:CHK) is the second-largest producer of natural gas and the 11th largest producer of oil and natural gas liquids 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, production growth and well connection forecasts, estimates of operating costs, planned development drilling and expected drilling cost reductions, capital expenditures, expected efficiency gains, anticipated assets sales and proceeds to be received therefrom, projected cash flow and liquidity, business strategy and other 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; write-downs of our oil and natural gas carrying values due to declines in prices; 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; the limitations our level of indebtedness may have on our financial flexibility; 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 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 March 31,	
	2015	**2014**
REVENUES:		
Oil, natural gas and NGL	$ 1,085	$ 1,766

Marketing, gathering and compression	1,675	3,015
Oilfield services	—	265
Total Revenues	2,760	5,046
OPERATING EXPENSES:		
Oil, natural gas and NGL production	299	288
Production taxes	28	50
Marketing, gathering and compression	1,700	2,980
Oilfield services	—	220
General and administrative	56	79
Restructuring and other termination costs	(10)	(7)
Provision for legal contingencies	25	—
Oil, natural gas and NGL depreciation, depletion and amortization	684	628
Depreciation and amortization of other assets	35	78
Impairment of oil and natural gas properties	4,976	—
Impairments of fixed assets and other	4	20
Net (gains) losses on sales of fixed assets	3	(23)
Total Operating Expenses	7,800	4,313
INCOME (LOSS) FROM OPERATIONS	(5,040)	733
OTHER INCOME (EXPENSE):		
Interest expense	(51)	(39)
Losses on investments	(7)	(21)
Net gain on sales of investments	—	67
Other income	6	6
Total Other Income (Expense)	(52)	13
INCOME (LOSS) BEFORE INCOME TAXES	(5,092)	746
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes	—	3
Deferred income taxes	(1,372)	277
Total Income Tax Expense (Benefit)	(1,372)	280
NET INCOME (LOSS)	(3,720)	466
Net income attributable to noncontrolling interests	(19)	(41)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(3,739)	425
Preferred stock dividends	(43)	(43)
Earnings allocated to participating securities	—	(8)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (3,782)	$ 374
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ (5.72)	$ 0.57
Diluted	$ (5.72)	$ 0.54
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	661	658
Diluted	661	765

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
($ in millions)
(unaudited)

	March 31, 2015	**December 31, 2014**
Cash and cash equivalents	$ 2,907	$ 4,108
Other current assets	2,491	3,360
Total Current Assets	5,398	7,468
Property and equipment, (net)	28,385	32,515

Other assets	590	768
Total Assets	$ 34,373	$ 40,751
Current liabilities	$ 5,366	$ 5,863
Long-term debt, net of discounts	10,623	11,154
Other long-term liabilities	1,194	1,344
Deferred income tax liabilities	2,817	4,185
Total Liabilities	20,000	22,546
Preferred stock	3,062	3,062
Noncontrolling interests	1,295	1,302
Common stock and other stockholders' equity	10,016	13,841
Total Equity	14,373	18,205
Total Liabilities and Equity	$ 34,373	$ 40,751
Common Shares Outstanding (in millions)	664	663

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
($ in millions)
(unaudited)

	March 31, 2015	December 31, 2014
Total debt, net of unrestricted cash	$ 8,601	$ 7,427
Preferred stock	3,062	3,062
Noncontrolling interests[a]	1,295	1,302
Common stock and other stockholders' equity	10,016	13,841
Total	$ 22,974	$ 25,632
Total net debt to capitalization ratio	37 %	29 %

[a] Includes third-party ownership as follows:

CHK Cleveland Tonkawa, L.L.C.	$ 1,015	$ 1,015
Chesapeake Granite Wash Trust	280	287
Total	$ 1,295	$ 1,302

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA – OIL, NATURAL GAS AND NGL PRODUCTION, SALES AND INTEREST EXPENSE
(unaudited)

	Three Months Ended March 31, 2015	2014
Net Production:		
Oil (mmbbl)	11.0	9.9
Natural gas (bcf)	263.8	260.0
NGL (mmbbl)	6.8	7.6
Oil equivalent (mmboe)	61.8	60.8
Oil, natural gas and NGL Sales ($ in millions):		
Oil sales	$ 451	$ 922

Oil derivatives – realized gains (losses)[a]	235	(84)
Oil derivatives – unrealized gains (losses)[a]	(110)	10
Total Oil Sales	576	848
Natural gas sales	425	1,005
Natural gas derivatives – realized gains (losses)[a]	200	(154)
Natural gas derivatives – unrealized gains (losses)[a]	(164)	(154)
Total Natural Gas Sales	461	697
NGL sales	48	221
Total NGL Sales	48	221
Total Oil, Natural Gas and NGL Sales	$ 1,085	$ 1,766
Average Sales Price – excluding gains (losses) on derivatives:		
Oil ($ per bbl)	$ 41.16	$ 93.60
Natural gas ($ per mcf)	$ 1.61	$ 3.86
NGL ($ per bbl)	$ 6.99	$ 29.23
Oil equivalent ($ per boe)	$ 14.96	$ 35.35
Average Sales Price – including realized gains (losses) on derivatives:		
Oil ($ per bbl)	$ 62.57	$ 85.08
Natural gas ($ per mcf)	$ 2.37	$ 3.27
NGL ($ per bbl)	$ 6.99	$ 29.23
Oil equivalent ($ per boe)	$ 22.00	$ 31.44
Interest Expense ($ in millions):		
Interest[b]	$ 62	$ 58
Derivatives – realized (gains) losses[c]	(1)	(3)
Derivatives – unrealized (gains) losses[c]	(10)	(16)
Total Interest Expense	$ 51	$ 39

(a) 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.

(b) Net of amounts capitalized.

(c) 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)

	March 31,	**March 31,**

THREE MONTHS ENDED:	2015	2014
Beginning cash	$ 4,108	$ 837
Cash provided by operating activities	423	1,291
Cash flows from investing activities:		
Drilling and completion costs[a]	(1,306)	(897)
Acquisition of proved and unproved properties[b]	(128)	(187)
Proceeds from divestitures of proved and unproved properties	21	49
Additions to other property and equipment	(58)	(97)
Cash paid to purchase leased rigs and compressors	—	(340)
Proceeds from sales of other property and equipment	2	239
Additions to investments	(3)	(3)
Proceeds from sales of investments	—	239
Other	—	(2)
Total cash used in investing activities	(1,472)	(999)
Cash used in financing activities	(152)	(125)
Change in cash and cash equivalents	(1,201)	167
Ending cash	$ 2,907	$ 1,004

(a) Includes capitalized interest of $11 million and $16 million for the three months ended March 31, 2015 and 2014, respectively.
(b) Includes capitalized interest of $109 million and $158 million for the three months ended March 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:	March 31, 2015	December 31, 2014	March 31, 2014
Net income (loss) available to common stockholders	$ (3,782)	$ 586	$ 374
Adjustments, net of tax:			
Unrealized (gains) losses on derivatives	192	(663)	80
Restructuring and other termination costs	(7)	(3)	(4)
Provision for legal contingencies	18	94	—
Impairment of oil and natural gas properties	3,635	—	—
Impairments of fixed assets and other	3	10	12
Net (gains) losses on sales of fixed assets	2	2	(14)
Net gain on sales of investments	—	—	(42)
Losses on purchases of debt and extinguishment of other financing	—	2	—
Tax rate adjustment	(17)	—	—
Other	(2)	6	(1)
Adjusted net income available to common stockholders[a]	$ 42	$ 34	$ 405
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	—	10	8
Total adjusted net income attributable to Chesapeake	$ 85	$ 87	$ 456

Weighted average fully diluted shares outstanding (in millions)[b]	776	775	767
Adjusted earnings per share assuming dilution[a]	$ 0.11	$ 0.11	$ 0.59

(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:	**March 31, 2015**	**December 31, 2014**	**March 31, 2014**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 423	$ 829	$ 1,291
Changes in assets and liabilities	487	44	323
OPERATING CASH FLOW[a]	$ 910	$ 873	$ 1,614

THREE MONTHS ENDED:	**March 31, 2015**	**December 31, 2014**	**March 31, 2014**
NET INCOME (LOSS)	$ (3,720)	$ 668	$ 466
Interest expense	51	7	39
Income tax expense (benefit)	(1,372)	286	280
Depreciation and amortization of other assets	35	38	78
Oil, natural gas and NGL depreciation, depletion and amortization	684	706	628
EBITDA[b]	$ (4,322)	$ 1,705	$ 1,491

THREE MONTHS ENDED:	**March 31, 2015**	**December 31, 2014**	**March 31, 2014**

CASH PROVIDED BY OPERATING ACTIVITIES	$ 423	$ 829	$ 1,291
Changes in assets and liabilities	487	44	323
Interest expense, net of unrealized gains (losses) on derivatives	61	38	55
Oil, natural gas and NGL derivative gains (losses), net	161	1,049	(382)
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(413)	(88)	168
Stock-based compensation	(23)	—	(20)
Restructuring and other termination costs	10	(3)	9
Provision for legal contingencies	(25)	(134)	—
Impairment of oil and natural gas properties	(4,976)	—	—
Impairments of fixed assets and other	(2)	(14)	(12)
Net gains (losses) on sales of fixed assets	(3)	(2)	23
Losses on investments	(7)	(7)	(21)
Net gain on sales of investments	—	—	67
Losses on purchases of debt and extinguishment of other financing	—	(2)	—
Other items	(15)	(5)	(10)
EBITDA[(b)]	$ (4,322)	$ 1,705	$ 1,491

(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 investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to 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:	**March 31, 2015**	**December 31, 2014**	**March 31, 2014**
EBITDA	$ (4,322)	$ 1,705	$ 1,491
Adjustments:			
Unrealized (gains) losses on oil, natural gas and NGL derivatives	274	(916)	144
Restructuring and other termination costs	(10)	(5)	(7)
Provision for legal contingencies	25	134	—

Impairment of oil and natural gas properties	4,976	—	—
Impairments of fixed assets and other	4	14	20
Net (gains) losses on sales of fixed assets	3	3	(23)
Net gains on sales of investments	—	—	(67)
Losses on purchases of debt and extinguishment of other financing	—	2	—
Net income attributable to noncontrolling interests	(19)	(29)	(41)
Other	(3)	8	(2)
Adjusted EBITDA[a]	$ 928	$ 916	$ 1,515

(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.

SCHEDULE "A”
CHESAPEAKE ENERGY CORPORATION
MANAGEMENT’S OUTLOOK AS OF MAY 6, 2015

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

	Year Ending 12/31/2015
Adjusted Production Growth[a]	1% – 3%
Absolute Production	
Liquids - mmbbls	62 – 64
Oil - mmbbls	38.5 – 39.5
NGL[b] - mmbbls	23.5 – 24.5
Natural gas - bcf	1,025 – 1,040
Total absolute production - mmboe	233 – 237
Absolute daily rate - mboe	640 – 650
Estimated Realized Hedging Effects[c] (based on 4/30/15 strip prices):	
Oil - $/bbl	$19.33
Natural gas - $/mcf	$0.32
Estimated Basis/Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Oil - $/bbl	$7.00 – 9.00
Natural gas - $/mcf	$1.70 – 1.90
NGL - $/bbl	$49.00 – 51.00
Fourth quarter minimum volume commitment (MVC) estimate ($ in millions)	($180) – (200)
Operating Costs per Boe of Projected Production:	
Production expense	$4.50 – 5.00
Production taxes	$0.45 – 0.55

General and administrative[(d)]	$1.45 – 1.55
Stock-based compensation (noncash)	$0.20 – 0.25
DD&A of natural gas and liquids assets	$9.50 – 10.50
Depreciation of other assets	$0.60 – 0.70
Interest expense[(e)]	$1.10 – 1.20
Other ($ millions):	
Marketing, gathering and compression net margin[(f)]	($40 – 60)
Net income attributable to noncontrolling interests and other[(g)]	($30 – 50)
Book Tax Rate	25% – 30%
Capital Expenditures ($ in millions)[(h)]	$3,000 – 3,500
Capitalized Interest ($ in millions)	$475
Total Capital Expenditures ($ in millions)	$3,475 – 3,975

(a) Based on 2014 production of 622 mboe/day adjusted for 2014 sales and the potential sale of Cleveland Tonkawa assets in 2015.
(b) Assumes ethane recovery in the Utica to fulfill Chesapeake's pipeline commitments, no ethane recovery in the Powder River Basin and partial ethane recovery in the Mid-Continent and Eagle Ford.
(c) Includes expected settlements for commodity derivatives adjusted for option premiums. For derivatives closed early, settlements are reflected in the period of original contract expiration.
(d) Excludes expenses associated with stock-based compensation.
(e) Excludes unrealized gains (losses) on interest rate derivatives.
(f) Includes revenue and operating expenses and excludes depreciation and amortization of other assets.
(g) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust and CHK Cleveland Tonkawa L.L.C.
(h) Includes capital expenditures for drilling and completion, leasehold, geological and geophysical costs and other property and plant and equipment.

Oil, Natural Gas and NGL Hedging Activities

Chesapeake enters into oil, natural gas and NGL 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, natural gas and NGL derivatives.

As of April 30, 2015, the company had downside protection on approximately 43% of its remaining projected 2015 oil production at an average price of $93.48 per bbl of which 12% is hedged under three-way collar arrangements based on an average bought put NYMEX price of $90 per bbl and exposure below an average sold put NYMEX price of $80 per bbl. Approximately 40% of the company's remaining projected 2015 natural gas production has downside protection at an average price of $3.85 per one thousand cubic feet of natural gas (mcf), of which 14% is hedged under three-way collar arrangements based on an average bought put NYMEX price of $4.17 per mcf and exposure below an average sold put NYMEX price of $3.38 per mcf.

The company's crude oil hedging positions as of April 30, 2015, were as follows:

Open Crude Oil Swaps; Gains (Losses) from Closed Crude Oil Trades and Call Option Premiums

	Avg. NYMEX	Total Gains from Closed Trades and Premiums for

	Open Swaps (mbbls)	Price of Open Swaps	Call Options ($ in millions)
Q2 2015	3,041	$ 94.49	$ 61
Q3 2015	2,868	94.82	62
Q4 2015	2,714	95.15	63
Total Q2 - Q4 2015	8,623	$ 94.81	$ 186
Total 2016 – 2022	—	$ —	$ 117

Crude Oil Three-Way Collars

	Open Collars (mbbls)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q2 2015	1,092	$ 80.00	$ 90.00	$ 98.94
Q3 2015	1,104	80.00	90.00	98.94
Q4 2015	1,104	80.00	90.00	98.94
Total Q2 - Q4 2015	3,300	$ 80.00	$ 90.00	$ 98.94

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price
Q2 2015	3,349	$ 91.89
Q3 2015	3,386	91.89
Q4 2015	3,386	91.89
Total Q2 - Q4 2015	10,121	$ 91.89
Total 2016 – 2017	24,220	$ 100.07

Crude Oil Basis Protection Swaps

	Volume (mbbls)	Avg. NYMEX plus
Q2 2015	1,740	$ 5.04
Q3 2015	2,392	3.14
Q4 2015	2,361	3.14
Total Q2 - Q4 2015	6,493	$ 3.65

The company’s natural gas hedging positions as of April 30, 2015 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 Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)
Q2 2015	70	$ 3.64	$ (30)
Q3 2015	78	3.54	(31)
Q4 2015	52	3.94	(31)
Total Q2 - Q4 2015	200	$ 3.68	$ (92)
Total 2016 – 2022	37	$ 3.95	$ (187)

Natural Gas Three-Way Collars

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q2 2015	35	$ 3.38	$ 4.17	$ 4.37
Q3 2015	36	3.38	4.17	4.37
Q4 2015	36	3.38	4.17	4.37
Total Q2 - Q4 2015	107	$ 3.38	$ 4.17	$ 4.37

Natural Gas Net Written Call Options

	Call Options (bcf)	Avg. NYMEX Strike Price
Total 2016 – 2020	193	$ 9.92

Natural Gas Basis Protection Swaps

	Volume (bcf)	Avg. NYMEX plus/(minus)
Q2 2015	22	$ (0.70)
Q3 2015	37	(0.82)
Q4 2015	10	(0.34)
Total Q2 - Q4 2015	69	$ (0.71)
Total 2016 - 2022	27	$ (0.56)

Source: Chesapeake Energy Corporation

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https://investors.chk.com/2015-05-06-chesapeake-energy-corporation-reports-2015-first-quarter-financial-and-operational-results