NEWS RELEASE

Chesapeake Energy Corporation Reports 2015 Second Quarter Financial and Operational Results

OKLAHOMA CITY--(BUSINESS WIRE)--Aug. 5, 2015-- Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operational results for the 2015 second quarter. Highlights include:

• Production averaged approximately 703,000 boe per day, an increase of 13% year over year, adjusted for asset sales

• Adjusted net loss of $0.11 per fully diluted share and adjusted ebitda of $600 million

• 2015 total production guidance increased to 667 – 677 mboe per day, up 4% from midpoint of prior guidance

• 2015 production and general and administrative expense guidance lowered

• 2015 capital guidance maintained at $3.5 – $4.0 billion

• Strategic asset sales, joint ventures and participation agreements being pursued in multiple operating areas

Doug Lawler, Chesapeake's Chief Executive Officer, commented, "The downturn in commodity prices has presented a severe test to our industry. Despite the challenges, we remain focused on lowering costs and improving operational efficiencies in our portfolio of high-quality assets. Production for the quarter was very strong, growing by 13% over last year and 2% sequentially when adjusting for asset sales, primarily driven by base optimization and increased well productivity from larger completions. We are currently expecting a stronger production trajectory as we enter 2016 and, as a result, we have raised our 2015 production guidance by 4%. We currently expect our 2015 exit rate to be approximately 660,000 barrels of oil equivalent per day, despite our voluntary curtailment of 50,000 net boe per day and the sharply reduced 2015 drilling activity. Our 2015 second quarter drilling and completion capital program was executed as planned, and we expect to stay within our annual capex guidance of $3.5 – $4.0 billion. While we strive to remain flexible in the face of lower commodity prices, we continue to focus on driving our costs lower. We have reduced our guidance for production and general and administrative expenses due to the outstanding job our employees have done in managing our controllable costs."

Lawler continued, "The improvements in our capital efficiency over the last two years have served to increase the unrecognized value of our assets. Further, I believe the strength and optionality of our portfolio provides meaningful opportunities to increase our liquidity and future cash flow. As a result, we are reviewing opportunities in multiple operating areas to create additional value through strategic asset sales, joint venture agreements and participation, or farmout agreements. Options for potential transaction proceeds include additional drilling in 2016 and enhancing our capital structure. We are not finished with the transformation of Chesapeake into a top-tier E&P company, and we look forward to the opportunities that lie ahead."

2015 Second Quarter Financial Results

For the 2015 second quarter, Chesapeake reported a net loss available to common stockholders of $4.151 billion, or $6.27 per fully diluted share, which compares to net income available to common stockholders of $145 million, or $0.22 per fully diluted share, in the 2014 second quarter. Items typically excluded by securities analysts in their earnings estimates reduced 2015 second quarter net income by approximately $4.025 billion on an after-tax basis and are presented on Page 12 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 June 30, 2015, compared to March 31, 2015. Adjusting for this and other items, the 2015 second quarter net loss available to common stockholders was $126 million, or $0.11 per fully diluted share, which compares to adjusted net income available to common stockholders of $235 million, or $0.36 per fully diluted share, in the 2014 second quarter.

Adjusted ebitda was $600 million in the 2015 second quarter, compared to $1.277 billion in the 2014 second quarter. Operating cash flow was $606 million in the 2015 second quarter, compared to $1.269 billion in the 2014 second 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, partially offset by increases in realized hedging gains and lower production and general and administrative (G&A) costs.

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 12 – 16 of this release.

2015 Second Quarter Average Daily Production of 703,000 Boe Increased 13% Year Over Year and 2% Sequentially, Adjusted for Asset Sales

Chesapeake's daily production for the 2015 second quarter averaged approximately 703,000 barrels of oil equivalent (boe), a year-over-year increase of 13%, adjusted for asset sales. Average daily production in the 2015 second quarter consisted of approximately 119,500 barrels (bbls) of oil, 3.0 billion cubic feet (bcf) of natural gas and 79,200 bbls of NGL, which represent year-over-year increases of 11%, 11% and 24%, respectively, adjusted for asset sales.

Capital Spending and Cost Overview

Chesapeake's 2015 second quarter drilling and completion capital expenditures decreased 39% sequentially to approximately $787 million, and capital expenditures for leasehold, geological and geophysical costs and other property, plant and equipment decreased 11% sequentially to approximately $56 million, for a total of approximately $843 million. Total capital expenditures, including capitalized interest of $114 million, decreased 36% and 38% to approximately $957 million in the 2015 second quarter, compared to approximately $1.5 billion in the 2015 first quarter and $1.6 billion in the 2014 second quarter, respectively, and are detailed below.

Activity Comparison	2015 Q2	2015 Q1	2014 Q2

Average operated rig count	26	54	65
Gross wells completed	121	261	294
Gross wells spud	109	244	286
Gross wells connected	173	262	275

Type of Cost ($ in millions)

Drilling and completion costs	$787	$1,300	$1,131
Leasehold, G&G and other PP&E	56	63	184
Subtotal capital spending	**$843**	**$1,363**	**$1,315**
Capitalized interest	114	123	155
Purchases of previously leased equipment	—	—	82
Total capital spending	**$957**	**$1,486**	**$1,552**

Chesapeake's focus on cost discipline continued to generate reductions in production and G&A expenses. Production expenses during the 2015 second quarter were $4.32 per boe. G&A expenses (including stock-based compensation) during the 2015 second quarter were $1.08 per boe. Combined production expenses and G&A expenses (including stock-based compensation) during the 2015 second quarter were $5.40 per boe, a decrease of 8% year over year.

A summary of the company’s guidance for 2015 is provided in the Outlook dated August 5, 2015, beginning on Page 17.

Operational Results – Southern Division

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately 105 thousand barrels of oil equivalent (mboe) per day (223 gross operated mboe per day) during the 2015 second quarter, a decrease of 7% sequentially. The sequential decrease in Eagle Ford production was due to gathering and treatment facility downtime for more than 60 days in May and June which reduced total net production volume over that period by approximately 14 mboe per day. The facility has since been repaired and was placed back in service July 1, 2015. The 2015 first quarter average completed well cost was $5.2 million with an average completed lateral length of 5,700 feet and 20 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. Chesapeake continues to realize significant cost reductions on both a drilling capital per foot and on a completion capital per-foot basis. That trend is expected to continue in subsequent quarters while overall completed well costs will increase as the company invests in longer laterals and larger completions in the area. The company has drilled six wells with more than 9,000 foot laterals, is currently drilling a 13,000 foot lateral and intends to spud its first upper Eagle Ford well in the 2015 third quarter. Operated rig count in the Eagle Ford averaged six rigs in the 2015 second quarter, down from 20 a year ago, and the company anticipates maintaining three operated rigs for the second half of the year.

Haynesville Shale and Bossier Shales (Northwest Louisiana): Haynesville net production averaged approximately 669 million cubic feet of natural gas (mmcf) per day (1.08 gross operated bcf per day) during the 2015 second quarter, an increase of 32% year over year and 9% sequentially. The sequential increase in Haynesville production was due to outstanding well performance from 15 new wells turned in line and minimal base decline seen from wells turned in line in the 2015 first quarter. Significant production growth realized to date in the Barnett and Haynesville combined with the anticipated volumes to come online in the second half of 2015, has allowed the company to decrease the midpoint of the estimated total midstream volume commitment shortfall payment in 2015 by $20 million as seen in the Outlook, beginning on Page 17. The 2015 first quarter average completed well cost was $7.9 million with an average completed lateral length of 4,900 feet and 13 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. Chesapeake's unique continuous blocks of leasehold provide a competitive advantage and the ability to extend laterals from two units to four units. In combination with further enhancement of completions in the Haynesville, this is significantly improving well performance and profitability in a low natural gas price environment. Operated rig count in the Haynesville averaged six rigs in the 2015 second quarter, down from eight a year ago, and the company anticipates increasing to seven operated rigs for the second half of the year.

Mid-Continent:

Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 32 mboe per day (77 gross operated mboe per day) during the 2015 second quarter, an increase of 1% sequentially. The 2015 first quarter average completed well cost was $2.8 million with an average completed lateral length of 4,450 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. The company continues to realize efficiencies, and recent completed well costs are under $2.7 million. Chesapeake's outstanding leasehold position and efficient operations continue to deliver strong returns even in the current oil price environment. Operated rig count in the Mississippian Lime averaged four rigs in the 2015 second quarter, down from eight a year ago, and the company anticipates maintaining two operated rigs for the second half of the year.

Oklahoma STACK (Northwest and Central Oklahoma): The company has identified multiple stacked and staggered liquids-rich opportunities on its extensive Oklahoma STACK leasehold position that is essentially all held by production. Two wells Chesapeake recently turned in line from the Oswego and Hoxbar formations delivered peak 24-hour oil rates of 1,955 and 1,515 bbls of oil per day. Completed costs for the aforementioned wells were $5.9 million and $7.1 million, respectively. The company believes well costs for both formations can be driven lower by more than 30% and anticipates greater efficiencies over time. The company intends to move a rig into the STACK in the 2015 third quarter which will focus on the Meramec and other formations.

Operational Results – Northern Division

Utica Shale (Eastern Ohio): Utica net production averaged approximately 124 mboe per day (222 gross operated mboe per day) during the 2015 second quarter, an increase of 13% sequentially. Chesapeake voluntarily curtailed an average of approximately 100 gross mmcf per day of Utica production in July 2015 and is currently curtailing 275 gross mmcf per day as a result of weak in-basin natural gas prices and the deterioration of propane prices. The company anticipates maintaining curtailment until a new regional pipeline is placed in-service in November 2015. The pipeline will allow the company to move approximately 350 gross mmcf per day out of the basin providing a very competitive basin transportation rate. Chesapeake anticipates a significant pricing uplift on these volumes due to access to the Gulf Coast market. The company continues to utilize ethane rejection in order to maximize its natural gas price realizations. The 2015 first quarter average completed well cost was $8.5 million with an average completed lateral length of 8,000 feet and 43 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 anticipates overall Utica completed well costs will increase as the company invests in longer laterals and larger completions in the area. Operated rig count in the Utica averaged four rigs in the 2015 second quarter, down from eight a year ago, and the company anticipates maintaining two operated rigs for the second half of the year.

Marcellus Shale (Northern Pennsylvania): Marcellus net production averaged approximately 820 mmcf per day (1.84 gross operated bcf per day) during the 2015 second quarter, a decrease of 1% sequentially. Chesapeake began voluntarily curtailing 300 gross mmcf per day of Marcellus production in the 2015 first quarter, and has since increased to 500 gross mmcfe per day in the 2015 second quarter as result of weak in-basin pricing due to pipeline constraints. The company anticipates maintaining Marcellus curtailments for the remainder of the year. The 2015 first quarter average completed well cost was $7.5 million with an average completed lateral length of 6,900 feet and 28 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 continues to realize efficiencies and recent completed well costs are under $6.7 million. Operated rig count in the Marcellus averaged one rig in the 2015 second quarter, down from six a year ago, and the company anticipates maintaining one operated rig for the second half of the year.

Powder River Basin (PRB) (Wyoming): PRB net production averaged approximately 20 mboe per day (32 gross operated mboe per day) during the 2015 second quarter, an increase of 1% sequentially. The 2015 first quarter average completed well cost was $11.0 million with an average completed lateral length of 6,000 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 continues to realize efficiencies and recent completed well costs are under $8.7 million. Chesapeake continues to optimize its completions and test various cluster spacing in the Sussex formation as it has drilled 20 wells to date with 12 of those currently producing. The company anticipates exclusively drilling Sussex wells for the remainder of the year with the exception of two test wells expected to be drilled in the Teapot formation and the Parkman E formation in the 2015 third and fourth quarters, respectively. Operated rig count in the PRB averaged one rig in the 2015 second quarter, down from three a year ago, and the company anticipates maintaining one operated rig for the second half of the year.

Key Financial and Operational Results

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

	Three Months Ended		
	06/30/15	**03/31/15**	**06/30/14**
Oil equivalent production (in mmboe)	63.9	61.8	63.2
Oil production (in mmbbls)	10.8	11.0	10.3
Average realized oil price ($/bbl)[a]	67.91	62.57	85.23
Oil as % of total production	17	18	16
Natural gas production (in bcf)	275.4	263.8	271.3
Average realized natural gas price ($/mcf)[a]	1.01	2.37	2.45
Natural gas as % of total production	72	71	72
NGL production (in mmbbls)	7.2	6.8	7.7
Average realized NGL price ($/bbl)[a]	1.90	6.99	21.03
NGL as % of total production	11	11	12
Production expenses ($/boe)	(4.32)	(4.84)	(4.46)
Production taxes ($/boe)	(0.52)	(0.45)	(1.14)
General and administrative costs ($/boe)[b]	(0.89)	(0.72)	(1.25)
Stock-based compensation ($/boe)	(0.19)	(0.19)	(0.18)

DD&A of natural gas and liquids properties ($/boe)	(9.39)	(11.08)	(10.45)
DD&A of other assets ($/boe)	(0.52)	(0.57)	(1.25)
Interest expense ($/boe)[(a)]	(1.12)	(0.98)	(0.92)
Marketing, gathering and compression net margin ($ in millions)[(c)]	209	(25)	1
Oilfield services net margin ($ in millions)[(d)]	—	—	69
Operating cash flow ($ in millions)[(e)]	606	910	1,269
Operating cash flow ($/boe)	9.49	14.73	20.07
Adjusted ebitda ($ in millions)[(f)]	600	928	1,277
Adjusted ebitda ($/boe)	9.37	15.02	20.20
Net income (loss) available to common stockholders ($ in millions)	(4,151)	(3,782)	145
Earnings (loss) per share – diluted ($)	(6.27)	(5.72)	0.22
Adjusted net income (loss) available to common stockholders ($ in millions)[(g)]	(126)	42	235
Adjusted earnings (loss) per share – diluted ($)	(0.11)	0.11	0.36

(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, operating expenses and $220 million of unrealized gains on supply contract derivatives. Excludes depreciation and amortization of other assets.

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

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

(f) 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 16.

(g) Defined as net income available to common stockholders, as adjusted to remove the effects of certain items detailed on Page 12.

2015 Second Quarter Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday, August 5, 2015 at 9:00 am EDT. The telephone number to access the conference call is **913-312-0648** or toll-free **800-930-1344**. The passcode for the call is **8058511**. 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, August 5, 2015, and will run through 2:00 pm EDT on Wednesday, August 19, 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 **8058511**. 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 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 and the effect on the unrecognized value of our assets, anticipated assets sales and proceeds to be received therefrom, projected cash flow and liquidity, business strategy and other opportunities, plans and objectives for future operations (including joint venture and participation agreements), 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 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 June 30, 2015	2014
REVENUES:		
Oil, natural gas and NGL	$ 728	$ 1,704
Marketing, gathering and compression	2,305	3,167
Oilfield services	—	281
Total Revenues	3,033	5,152
OPERATING EXPENSES:		
Oil, natural gas and NGL production	276	282
Production taxes	34	72
Marketing, gathering and compression	2,096	3,166
Oilfield services	—	212
General and administrative	69	90
Restructuring and other termination costs	(4)	33
Provision for legal contingencies	334	—
Oil, natural gas and NGL depreciation, depletion and amortization	601	661
Depreciation and amortization of other assets	34	79
Impairment of oil and natural gas properties	5,015	—
Impairments of fixed assets and other	84	40
Net (gains) losses on sales of fixed assets	1	(93)
Total Operating Expenses	8,540	4,542
INCOME (LOSS) FROM OPERATIONS	(5,507)	610
OTHER INCOME (EXPENSE):		
Interest expense	(71)	(27)
Losses on investments	(17)	(24)
Losses on purchases of debt	—	(195)
Other income (expense)	(1)	7
Total Other Expense	(89)	(239)
INCOME (LOSS) BEFORE INCOME TAXES	(5,596)	371
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes	(6)	5
Deferred income taxes	(1,500)	136
Total Income Tax Expense (Benefit)	(1,506)	141
NET INCOME (LOSS)	(4,090)	230
Net income attributable to noncontrolling interests	(18)	(39)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(4,108)	191
Preferred stock dividends	(43)	(43)
Earnings allocated to participating securities	—	(3)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (4,151)	$ 145
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ (6.27)	$ 0.22
Diluted	$ (6.27)	$ 0.22

WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):

Basic	662	659
Diluted	662	659

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ in millions, except per share data)
(unaudited)

	Six Months Ended June 30, 2015	**2014**
REVENUES:		
Oil, natural gas and NGL	$ 1,813	$ 3,471
Marketing, gathering and compression	3,980	6,182
Oilfield services	—	545
Total Revenues	5,793	10,198
OPERATING EXPENSES:		
Oil, natural gas and NGL production	575	570
Production taxes	62	122
Marketing, gathering and compression	3,796	6,147
Oilfield services	—	431
General and administrative	125	169
Restructuring and other termination costs	(14)	26
Provision for legal contingencies	359	—
Oil, natural gas and NGL depreciation, depletion and amortization	1,285	1,288
Depreciation and amortization of other assets	69	157
Impairment of oil and natural gas properties	9,991	—
Impairments of fixed assets and other	88	60
Net (gains) losses on sales of fixed assets	4	(115)
Total Operating Expenses	16,340	8,855
INCOME (LOSS) FROM OPERATIONS	(10,547)	1,343
OTHER INCOME (EXPENSE):		
Interest expense	(122)	(66)
Losses on investments	(24)	(45)
Net gain on sales of investments	—	67
Losses on purchases of debt	—	(195)
Other income	5	13
Total Other Expense	(141)	(226)
INCOME (LOSS) BEFORE INCOME TAXES	(10,688)	1,117
INCOME TAX EXPENSE (BENEFIT):		
Current income taxes	(6)	8
Deferred income taxes	(2,872)	413
Total Income Tax Expense (Benefit)	(2,878)	421
NET INCOME (LOSS)	(7,810)	696
Net income attributable to noncontrolling interests	(37)	(80)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(7,847)	616
Preferred stock dividends	(86)	(86)
Earnings allocated to participating securities	—	(12)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (7,933)	$ 518
EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ (11.99)	$ 0.79
Diluted	$ (11.99)	$ 0.78
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):		
Basic	662	658
Diluted	662	760

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

	June 30, 2015	December 31, 2014
Cash and cash equivalents	$ 2,051	$ 4,108
Other current assets	2,180	3,360
Total Current Assets	4,231	7,468
Property and equipment, (net)	23,615	32,515
Other assets	752	768
Total Assets	$ 28,598	$ 40,751
Current liabilities	$ 5,128	$ 5,863
Long-term debt, net of discounts	10,655	11,154
Other long-term liabilities	1,164	1,344
Deferred income tax liabilities	1,408	4,185
Total Liabilities	18,355	22,546
Preferred stock	3,062	3,062
Noncontrolling interests	1,285	1,302
Common stock and other stockholders' equity	5,896	13,841
Total Equity	10,243	18,205
Total Liabilities and Equity	$ 28,598	$ 40,751
Common Shares Outstanding (in millions)	663	663

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

	June 30, 2015	December 31, 2014
Total debt, net of unrestricted cash	$ 9,493	$ 7,427
Preferred stock	3,062	3,062
Noncontrolling interests[a]	1,285	1,302
Common stock and other stockholders' equity	5,896	13,841
Total	$ 19,736	$ 25,632
Total net debt to capitalization ratio	48 %	29 %

[a] Includes third-party ownership as follows:

CHK Cleveland Tonkawa, L.L.C	$ 1,015	$ 1,015
Chesapeake Granite Wash Trust	270	287
Total	$ 1,285	$ 1,302

CHESAPEAKE ENERGY CORPORATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
Net Production:				
Oil (mmbbl)	10.8	10.3	21.8	20.2
Natural gas (bcf)	275.4	271.3	539.2	531.4
NGL (mmbbl)	7.2	7.7	14.0	15.2
Oil equivalent (mmboe)	63.9	63.2	125.7	124.0
Oil, natural gas and NGL Sales ($ in millions):				
Oil sales	$557	$1,006	$1,008	$1,928
Oil derivatives – realized gains (losses)[a]	182	(127)	417	(210)
Oil derivatives – unrealized gains (losses)[a]	(234)	(113)	(344)	(103)
Total Oil Sales	505	766	1,081	1,615
Natural gas sales	206	750	631	1,754
Natural gas derivatives – realized gains (losses)[a]	71	(86)	271	(240)
Natural gas derivatives – unrealized gains (losses)[a]	(67)	113	(231)	(41)
Total Natural Gas Sales	210	777	671	1,473
NGL sales	13	161	61	383
Total NGL Sales	13	161	61	383
Total Oil, Natural Gas and NGL Sales	$728	$1,704	$1,813	$3,471
Average Sales Price – excluding gains (losses) on derivatives:				
Oil ($ per bbl)	$51.21	$97.49	$46.16	$95.59
Natural gas ($ per mcf)	$0.75	$2.76	$1.17	$3.30
NGL ($ per bbl)	$1.90	$21.03	$4.37	$25.10
Oil equivalent ($ per boe)	$12.13	$30.32	$13.52	$32.79
Average Sales Price – including realized gains (losses) on derivatives:				
Oil ($ per bbl)	$67.91	$85.23	$65.22	$85.16
Natural gas ($ per mcf)	$1.01	$2.45	$1.67	$2.85
NGL ($ per bbl)	$1.90	$21.03	$4.37	$25.10
Oil equivalent ($ per boe)	$16.08	$26.97	$18.99	$29.16
Interest Expense ($ in millions):				
Interest[b]	$72	$61	$134	$119
Derivatives – realized (gains) losses[c]	(1)	(3)	(2)	(6)
Derivatives – unrealized (gains) losses[c]	—	(31)	(10)	(47)
Total Interest Expense	$71	$27	$122	$66

(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)

THREE MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
Beginning cash	$ 2,907	$ 1,004
Net cash provided by operating activities	314	1,352
Cash flows from investing activities:		
Drilling and completion costs[a]	(862)	(1,099)
Acquisitions of proved and unproved properties[b]	(138)	(169)
Divestitures of proved and unproved properties	(7)	199
Additions to other property and equipment	(35)	(101)
Cash paid to purchase leased rigs and compressors	—	(82)
Proceeds from sales of other property and equipment	5	474
Additions to investments	(3)	(2)
Proceeds from sales of investments	—	—
Other	—	(1)
Net cash used in investing activities	(1,040)	(781)
Net cash used in financing activities	(130)	(113)
Change in cash and cash equivalents	(856)	458
Ending cash	$ 2,051	$ 1,462

(a) Includes capitalized interest of $7 million and $12 million for the three months ended June 30, 2015 and 2014, respectively.

(b) Includes capitalized interest of $104 million and $140 million for the three months ended June 30, 2015 and 2014, respectively.

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA
($ in millions)
(unaudited)

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
Beginning cash	$ 4,108	$ 837

Net cash provided by operating activities	737	2,643
Cash flows from investing activities:		
Drilling and completion costs[a]	(2,168)	(1,996)
Acquisitions of proved and unproved properties[b]	(266)	(356)
Divestitures of proved and unproved properties	14	248
Additions to other property and equipment	(93)	(198)
Cash paid to purchase leased rigs and compressors	—	(422)
Proceeds from sales of other property and equipment	7	713
Additions to investments	(6)	(5)
Proceeds from sales of investments	—	239
Other	—	(3)
Net cash used in investing activities	(2,512)	(1,780)
Net cash used in financing activities	(282)	(238)
Change in cash and cash equivalents	(2,057)	625
Ending cash	$ 2,051	$ 1,462

(a) Includes capitalized interest of $18 million and $28 million for the six months ended June 30, 2015 and 2014, respectively.

(b) Includes capitalized interest of $212 million and $298 million for the six months ended June 30, 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:	**June 30, 2015**	**March 31, 2015**	**June 30, 2014**
Net income (loss) available to common stockholders	$ (4,151)	$ (3,782)	$ 145
Adjustments, net of tax:			
Unrealized (gains) losses on commodity derivatives	220	192	(19)
Unrealized gains on supply contract derivatives	(161)	—	—
Restructuring and other termination costs	(3)	(7)	20
Provision for legal contingencies	244	18	—
Impairment of oil and natural gas properties	3,666	3,635	—
Impairments of fixed assets and other	61	3	25
Net (gains) losses on sales of fixed assets	1	2	(57)
Impairments of investments	—	—	3
Losses on purchases of debt	—	—	120
Tax rate adjustment	—	(17)	—
Other	(3)	(2)	(2)
Adjusted net income (loss) available to common stockholders[a]	$ (126)	$ 42	$ 235
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	—	—	3
Total adjusted net income (loss) attributable to Chesapeake	$ (83)	$ 85	$ 281
Weighted average fully diluted shares outstanding (in millions)[b]	777	776	776

Adjusted earnings (loss) per share assuming dilution[a]	$ (0.11)	$ 0.11	$ 0.36

(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)

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
Net income (loss) available to common stockholders	$ (7,933)	$ 518
Adjustments, net of tax:		
Unrealized losses on commodity derivatives	412	61
Unrealized gains on supply contract derivatives	(161)	—
Restructuring and other termination costs	(10)	16
Provision for legal contingencies	262	—
Impairment of oil and natural gas properties	7,301	—
Impairments of fixed assets and other	64	37
Net (gains) losses on sales of fixed assets	3	(72)
Impairments of investments	—	3
Net gain on sales of investments	—	(42)
Losses on purchases of debt	—	121
Tax rate adjustment	(17)	—
Other	(5)	(3)
Adjusted net income (loss) available to common stockholders[a]	$ (84)	$ 639
Preferred stock dividends	86	86
Earnings allocated to participating securities	—	12
Total adjusted net income attributable to Chesapeake	$ 2	$ 737
Weighted average fully diluted shares outstanding (in millions)[b]	777	776

Adjusted earnings per share assuming dilution[a]	$ 0.00	$ 0.95

(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:	**June 30, 2015**	**March 31, 2015**	**June 30, 2014**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 314	$ 423	$ 1,352
Changes in assets and liabilities	292	487	(83)
OPERATING CASH FLOW[a]	$ 606	$ 910	$ 1,269

THREE MONTHS ENDED:	**June 30, 2015**	**March 31, 2015**	**June 30, 2014**
NET INCOME (LOSS)	$ (4,090)	$ (3,720)	$ 230
Interest expense	71	51	27
Income tax expense (benefit)	(1,506)	(1,372)	141
Depreciation and amortization of other assets	34	35	79
Oil, natural gas and NGL depreciation, depletion and amortization	601	684	661
EBITDA[b]	$ (4,890)	$ (4,322)	$ 1,138

THREE MONTHS ENDED:	**June 30, 2015**	**March 31, 2015**	**June 30, 2014**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 314	$ 423	$ 1,352
Changes in assets and liabilities	292	487	(83)

Interest expense, net of unrealized gains (losses) on derivatives	71	61	58
Gains (losses) on commodity derivatives, net	(48)	161	(213)
Gains on supply contract derivatives, net	220	—	—
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(223)	(413)	150
Stock-based compensation	(20)	(23)	(20)
Restructuring and other termination costs	4	10	(33)
Provision for legal contingencies	(334)	(25)	—
Impairment of oil and natural gas properties	(5,015)	(4,976)	—
Impairments of fixed assets and other	(79)	(2)	(39)
Net gains (losses) on sales of fixed assets	(1)	(3)	93
Losses on investments	(17)	(7)	(24)
Losses on purchases of debt	—	—	(61)
Other items	(54)	(15)	(42)
EBITDA(b)	$ (4,890)	$ (4,322)	$ 1,138

(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 OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 737	$ 2,643
Changes in assets and liabilities	779	240
OPERATING CASH FLOW(a)	$ 1,516	$ 2,883

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
NET INCOME (LOSS)	$ (7,810)	$ 696
Interest expense	122	66
Income tax expense (benefit)	(2,878)	421
Depreciation and amortization of other assets	69	157
Oil, natural gas and NGL depreciation, depletion and amortization	1,285	1,288

EBITDA[b]	$(9,212)	$ 2,628

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
CASH PROVIDED BY OPERATING ACTIVITIES	$737	$2,643
Changes in assets and liabilities	779	240
Interest expense, net of unrealized gains (losses) on derivatives	132	113
Gains (losses) on commodity derivatives, net	113	(595)
Gains on supply contract derivatives, net	220	—
Cash (receipts) payments on oil, natural gas and NGL derivative settlements, net	(636)	318
Stock-based compensation	(43)	(40)
Restructuring and other termination costs	14	(24)
Provision for legal contingencies	(359)	—
Impairment of oil and natural gas properties	(9,991)	—
Impairments of fixed assets and other	(81)	(51)
Net gains (losses) on sales of fixed assets	(4)	115
Losses on investments	(24)	(45)
Net gain on sales of investments	—	67
Losses on purchases of debt	—	(61)
Other items	(69)	(52)
EBITDA[b]	$(9,212)	$2,628

(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:	**June 30, 2015**	**March 31, 2015**	**June 30, 2014**
EBITDA	$(4,890)	$ (4,322)	$1,138
Adjustments:			
Unrealized losses on oil, natural gas and NGL derivatives	301	274	—

Unrealized gains on supply contract derivatives	(220)	—	—
Restructuring and other termination costs	(4)	(10)	33
Provision for legal contingencies	334	25	—
Impairment of oil and natural gas properties	5,015	4,976	—
Impairments of fixed assets and other	84	4	40
Net (gains) losses on sales of fixed assets	1	3	(93)
Impairments of investments	—	—	5
Losses on purchases of debt	—	—	195
Net income attributable to noncontrolling interests	(18)	(19)	(39)
Other	(3)	(3)	(2)
Adjusted EBITDA[(a)]	$ 600	$ 928	$ 1,277

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in millions)
(unaudited)

SIX MONTHS ENDED:	**June 30, 2015**	**June 30, 2014**
EBITDA	$ (9,212)	$ 2,628
Adjustments:		
Unrealized losses on oil, natural gas and NGL derivatives	575	144
Unrealized gains on supply contract derivatives	(220)	—
Restructuring and other termination costs	(14)	26
Provision for legal contingencies	359	—
Impairment of oil and natural gas properties	9,991	—
Impairments of fixed assets and other	88	60
Net (gains) losses on sales of fixed assets	4	(115)
Impairments of investments	—	5
Net gains on sales of investments	—	(67)
Losses on purchases of debt	—	195
Net income attributable to noncontrolling interests	(37)	(80)
Other	(6)	(4)
Adjusted EBITDA[(a)]	$ 1,528	$ 2,792

(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 CORPORATION
MANAGEMENT’S OUTLOOK AS OF AUGUST 5, 2015

Chesapeake periodically provides management guidance on certain factors that affect the company’s future financial performance. Changes from the company's May 6, 2015 Outlook are ***italicized bold*** below.

	Year Ending 12/31/2015
Adjusted Production Growth[a]	***5% – 7%***
Absolute Production	
Liquids - mbbls	***67 – 69***
Oil - mbbls	***41.5 – 42.5***
NGL[b] - mbbls	***25.5 – 26.5***
Natural gas - bcf	***1,055 – 1,070***
Total absolute production - mmboe	***243 – 247***
Absolute daily rate - mboe	***667 – 677***
Estimated Realized Hedging Effects[c] (based on 7/31/15 strip prices):	
Oil - $/bbl	***$20.01***
Natural gas - $/mcf	***$0.37***
Estimated Basis/Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Oil - $/bbl	$7.00 – 9.00
Natural gas - $/mcf	***$1.65 – 1.85***
NGL - $/bbl	$49.00 – 51.00
Fourth quarter minimum volume commitment (MVC) estimate ($ in millions)	***($160) – (180)***
Operating Costs per Boe of Projected Production:	
Production expense	***$4.40 – 4.90***
Production taxes	$0.45 – 0.55
General and administrative[d]	***$1.25 – 1.35***
Stock-based compensation (noncash)	$0.20 – 0.25
DD&A of natural gas and liquids assets	***$8.50 – 9.50***
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]	***($60 – 65)***
Book Tax Rate	25% – 30%
Capital Expenditures ($ 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 per day adjusted for 2014 sales and the potential sale of Cleveland Tonkawa asset 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. Excludes depreciation and amortization of other assets and unrealized gains (losses) on supply contract derivatives.

(g) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust and, prior to its anticipated sale in the 2015 third quarter, 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 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 July 31, 2015, the company had downside protection on approximately 48% of its remaining projected 2015 oil production at an average price of $87.64 per bbl of which 11% 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 39% of the company's remaining projected 2015 natural gas production has downside protection at an average price of $3.87 per 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 July 31, 2015 were as follows:

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

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Total Gains from Closed Trades and Premiums for Call Options ($ in millions)
Q3 2015	3,788	$ 86.98	$ 62
Q4 2015	3,634	86.89	63
Total Q3 - Q4 2015	7,422	$ 86.94	$ 125
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
Q3 2015	1,104	$ 80.00	$ 90.00	$ 98.94
Q4 2015	1,104	80.00	90.00	98.94
Total Q3 - Q4 2015	2,208	$ 80.00	$ 90.00	$ 98.94

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price
Q3 2015	1,868	$ 85.31
Q4 2015	1,868	85.31
Total Q3 - Q4 2015	3,736	$ 85.31
Total 2016 – 2017	24,220	$ 100.07

Crude Oil Basis Protection Swaps

	Volume (mbbls)	Avg. NYMEX plus
Q3 2015	3,405	$ 3.52
Q4 2015	2,361	3.14
Total Q3 - Q4 2015	5,766	$ 3.36

The company's natural gas hedging positions as of July 31, 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 Losses from Closed Trades and Premiums for Call Options ($ in millions)
Q3 2015	78	$ 3.54	$ (31)
Q4 2015	53	3.94	(31)
Total Q3 - Q4 2015	131	$ 3.70	$ (62)
Total 2016 – 2022	169	$ 3.36	$ (187)

Natural Gas Three-Way Collars

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q3 2015	36	$ 3.38	$ 4.17	$ 4.37
Q4 2015	35	3.38	4.17	4.37
Total Q3 - Q4 2015	71	$ 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)
Q3 2015	37	$ (0.82)
Q4 2015	15	0.17
Total Q3 - Q4 2015	52	$ (0.54)
Total 2016 - 2022	48	$ (0.23)

View source version on businesswire.com: http://www.businesswire.com/news/home/20150805005512/en/

Source: Chesapeake Energy Corporation

Chesapeake Energy Corporation
INVESTOR CONTACT:
Brad Sylvester, CFA, 405-935-8870
ir@chk.com
or

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

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https://investors.chk.com/2015-08-05-chesapeake-energy-corporation-reports-2015-second-quarter-financial-and-operational-results