NEWS
RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2014 Third Quarter

OKLAHOMA CITY--(BUSINESS WIRE)--Nov. 5, 2014-- Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operational results for the 2014 third quarter. Key information is as follows:

- ***Company reports adjusted net income of $0.38 per fully diluted share and adjusted ebitda of $1.236 billion***
- ***Average production of approximately 726,000 boe per day increases 11% year over year, adjusted for asset sales***
- ***Capital expenditures of $1.351 billion decrease 8% year over year***
- ***Eagle Ford, Haynesville, Utica and Powder River Basin operating areas each achieve organic production growth in excess of 10% quarter over quarter***

"The improvements in our capital efficiency, our focus on cost leadership and the strength and quality of our assets and talented employees are very clear in our third quarter results," stated Doug Lawler, President and Chief Executive Officer of Chesapeake. "Our results this quarter were outstanding, as adjusted production increased 11% compared to the 2013 third quarter, increased 5% sequentially and already reached our year-end exit rate target of approximately 730,000 barrels of oil equivalent per day during the month of September. We have also seen a reduction in operating expenses compared to both the 2014 second quarter and the 2013 third quarter, and we continue to see dramatic improvement in capital efficiency throughout our operating areas. The company again exceeded its production growth target while operating below our capital budget. I am very proud of our results and believe they are further evidence that our strategy and commitment to becoming a top-tier E&P company will yield long-term stockholder value."

For the 2014 third quarter, Chesapeake reported net income available to common stockholders of $169 million, or $0.26 per fully diluted share. Items typically excluded by securities analysts in their earnings estimates reduced net income available to common stockholders for the 2014 third quarter by approximately $82 million and are presented on Page 12 of this release. The primary component of this reduction was the redemption of all the outstanding preferred shares of a subsidiary, partially offset by unrealized gains on our commodity derivatives. Adjusting for these items, 2014 third quarter adjusted net income available to common stockholders was $251 million, or $0.38 per fully diluted share, as compared to adjusted net income available to common stockholders of $282 million, or $0.43 per fully diluted share, in the 2013 third quarter.

Adjusted ebitda was $1.236 billion in the 2014 third quarter, compared to $1.325 billion in the 2013 third quarter. Operating cash flow, which is cash flow provided by operating activities before changes in assets and liabilities, was $1.293 billion in the 2014 third quarter, compared to $1.412 billion in the 2013 third 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 liquids (NGL) prices, partially offset by higher production volumes and lower operating expenses.

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 – 16 of this release.

2014 Third Quarter Average Daily Production of Approximately 726,000 Boe Increases 11% Year over Year, Adjusted for Asset Sales

Chesapeake’s daily production for the 2014 third quarter averaged 725,600 barrels of oil equivalent (boe), a year-over-year increase of 11%, adjusted for asset sales. Average daily production consisted of approximately 118,900 barrels (bbls) of oil, 95,900 bbls of NGL and 3.1 billion cubic feet (bcf) of natural gas.

Sequentially, 2014 third quarter average daily oil production increased 5%, average daily NGL production increased 14% and average daily natural gas production increased 3%, adjusted for asset sales.

Capital Spending and Cost Overview

Chesapeake's capital expenditures in the 2014 third quarter were approximately $1.351 billion, of which drilling and completion capital expenditures were approximately $1.241 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property, plant and equipment were approximately $110 million. In the 2013 third quarter, capital expenditures were approximately $1.461 billion, of which drilling and completion capital expenditures were approximately $1.248 billion and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property, plant and equipment were $213 million.

Drilling and completion expenditures in the 2014 third quarter increased approximately $110 million, or 10%, compared to the 2014 second quarter, primarily due to increased well completions and connections. Chesapeake spud a total of 296 gross wells and connected 311 gross wells to sales during the 2014 third quarter, compared to 324 gross wells spud and 275 gross wells connected to sales during the 2014 second quarter. The company reiterates its 2014 full-year total capital expenditure guidance of $5.0 – $5.4 billion, excluding capitalized interest and the company's exchange of properties with RKI Exploration & Production, LLC (RKI) (discussed below).

Chesapeake's focus on cost discipline continued to generate reductions in production and general and administrative expenses. Together, these costs (including share-based compensation) were $5.37 per boe in the 2014 third quarter, as compared to $5.89 in the 2014 second quarter and $6.47 in the 2013 third quarter.

A summary of the company’s guidance for 2014 is provided in the Outlook dated November 5, 2014, attached to this release as Schedule "A” beginning on Page 17.

Operations Update

As described below, Chesapeake has demonstrated significant improvements in its capital efficiency, cycle times and well cost reductions, all of which are driving competitive value creation for our stockholders.

Southern Division

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately

102.2 thousand barrels of oil equivalent (mboe) per day (224.5 gross operated mboe per day) during the 2014 third quarter, an increase of 12% sequentially. Chesapeake has achieved outstanding performance from its Eagle Ford operations and continues to experience drilling and completion cost savings. Average completed well costs (as measured from January through July) are approximately $6.0 million with an average completed lateral length of 6,300 feet and 20 frac stages, compared to an average of $6.9 million in 2013 with an average completed lateral length of 5,850 feet and 18 frac stages. The average of completed well costs is already significantly below the year-end 2014 target of $6.4 million per well. Cycle times from wells turned in line in 2014 third quarter have decreased to an average of approximately 135 days, spud to sales, from an average of 221 days in 2013. Wells in various stages of completion or waiting on pipeline in the area have increased to 152 as of September 30, 2014, compared to 109 wells at December 31, 2013, due to both increased activity and pad drilling efficiencies, however, the time spent in inventory is markedly shrinking. The average peak production rate of the 89 wells that commenced first production in the Eagle Ford during the 2014 third quarter was approximately 840 boe per day.

Haynesville Shale (Northwest Louisiana): Haynesville Shale net production averaged approximately 562 million cubic feet of natural gas equivalent (mmcfe) per day (855 gross operated mmcfe per day) during the 2014 third quarter, an increase of 11% sequentially. Chesapeake continues to achieve outstanding drilling and completion cost savings in its Haynesville operations. Average completed well costs (as measured from January through July) are approximately $8.2 million with an average completed lateral length of 5,050 feet and 20 frac stages, compared to an average of $8.9 million in 2013 with an average completed lateral length of 4,400 feet and 18 frac stages. The average of completed well costs is on track with the 2014 estimated average of $7.9 million per well despite incurring additional capital investment in cross unit laterals. Cycle times from wells turned in line in the 2014 third quarter have decreased to an average of approximately 146 days, spud to sales, from an average of 411 days in 2013. The average peak production rate of the 14 wells that commenced first production in the Haynesville during the 2014 third quarter was approximately 11.9 mmcfe per day.

Mid-Continent North: Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 27.3 mboe per day (66 gross operated mboe per day) during the 2014 third quarter, an increase of 4% sequentially. Chesapeake continues to deliver a greater rate of return from this asset due to pad drilling proficiencies, improved salt water disposal processes and better understanding of the geology. Average completed well costs (as measured from January through July) are approximately $3.1 million with an average completed lateral length of 4,650 feet, compared to an average of $3.5 million in 2013 with an average completed lateral length of 4,500 feet. The average of completed well costs is on track to deliver the year-end 2014 target of $2.9 million per well. The average peak production rate of the 44 wells that commenced first production in the Mississippian Lime during the 2014 third quarter was approximately 710 boe per day.

Northern Division

Utica Shale (Eastern Ohio): Utica net production averaged approximately 85.5 mboe per day (154.4 gross operated mboe per day) during the 2014 third quarter, an increase of 27% sequentially. Chesapeake anticipates incremental compression capacity of 150 mmcfe per day gross on the Cardinal pipeline in the 2014 fourth quarter. The company continues to improve its capital efficiencies within the Utica. Average completed well costs (as measured from January through July) are approximately $6.5 million with an average completed lateral length of 6,300 feet and 32 frac stages, compared to an average of $6.7 million in 2013 with an average completed lateral length of 5,150 feet and 17 frac stages. The average of completed well costs is already significantly below the year-end 2014 target of $7.1 million per well despite incurring additional capital reinvestment in completions. Wells in various stages of completion or waiting on pipeline in the area decreased to 172 as of September 30, 2014, compared to 195 at December 31, 2013. The average peak production rate of the 77 wells that commenced first production in the Utica during the 2014 third quarter was approximately 1,175 boe per day.

Marcellus Shale (Northern Pennsylvania): Northern Marcellus net production averaged approximately 882 mmcfe per day (2.08 gross operated bcfe per day) during the 2014 third quarter, an increase of 1% sequentially. In October 2014, the company connected to sales the Franclaire 8H in Wyoming County, Pennsylvania, which achieved a peak rate of 30.6 mmcf of natural gas per day. The well was one of five on the Franclaire drilling pad, from which production combined in aggregate achieved a peak rate of approximately 94 mmcf per day. Average completed well costs (as measured from January through July) are approximately $7.0 million with an average completed lateral length of 6,300 feet and 32 frac stages, compared to an average of $7.9 million in 2013 with an average completed lateral length of 5,400 feet and 13 frac stages. Laterals have increased 17%, the number of frac stages has nearly tripled and proppant per lateral foot has measurably increased all while total well costs have declined 11%. The average of completed well costs is on track with the year-end 2014 target of $6.9 million per well. Wells in various stages of completion or waiting on pipeline in the area increased to 125 as of September 30, 2014, compared to 112 at December 31, 2013, due to increased pad drilling. Cycle times continue to decrease and the company anticipates significant reduction to inventory over the next 12 months. The average peak production rate of the 23 wells that commenced first production in the northern Marcellus during the 2014 third quarter was approximately 13.4 mmcfe per day.

Powder River Basin (PRB): Niobrara and Upper Cretaceous (Wyoming): PRB net production averaged approximately 13.9 mboe per day (24.1 gross operated mboe per day) during the 2014 third quarter, an increase of 16% sequentially, adjusted for the RKI transaction, and an increase of 26% sequentially on an absolute basis. The company anticipates further production ramp as the Buckinghorse processing plant comes online in November providing capacity of approximately 120 mmcfe per day. The company is extremely proud of its capital efficiency improvements in the PRB to date. Average completed well costs (as measured from January through July) are approximately $9.2 million per well with an average completed lateral length of 5,300 feet and 17 frac stages, compared to an average of $10.1 million per well in 2013 with an average completed lateral length of 5,050 feet and 15 frac stages. The average of completed well costs is on track to meet the 2014 estimated average of $8.9 million per well despite incurring additional capital reinvestment in completions. Wells in various stages of completion or waiting on pipeline in the area decreased to 43 as of September 30, 2014, compared to 57 wells at December 31, 2013. The average peak production rate of the 17 wells that commenced first production in the Powder River Basin during the 2014 third quarter was approximately 1,475 boe per day.

Recent Strategic Transactions and Asset Sales Update

On October 14, 2014, Chesapeake entered into a purchase and sale agreement to sell certain assets in the southern Marcellus Shale and a portion of the eastern Utica Shale to a subsidiary of Southwestern Energy Company (NYSE:SWN) for aggregate proceeds of approximately $5.375 billion. The transaction, which is subject to certain customary closing conditions, including the receipt of third-party consents and waiver of participation rights, is expected to close in the 2014 fourth quarter.

In July 2014, Chesapeake repurchased all of the outstanding preferred shares of its unrestricted subsidiary CHK Utica, L.L.C. (CHK Utica) from third-party preferred shareholders. Chesapeake paid approximately $1.25 billion to repurchase 1,060,000 preferred shares of CHK Utica.

In August 2014, the company completed an exchange of properties in the Powder River Basin (PRB) with RKI. Chesapeake exchanged its nonoperated northern PRB acreage and $450 million in cash paid by the company for RKI's southern PRB acreage.

Key Financial and Operational Results

The table below summarizes Chesapeake’s key financial and operational results during the 2014 third quarter and compares them to results in prior periods.

	Three Months Ended		
	09/30/14	**06/30/14**	**09/30/13**
Oil equivalent production (in mmboe)	66.8	63.2	62.0
Oil production (in mmbbls)	10.9	10.3	11.0
Average realized oil price ($/bbl)[(a)]	84.81	85.23	92.09
Oil as % of total production	16	16	18
NGL production (in mmbbls)	8.8	7.7	5.4
Average realized NGL price ($/bbl)[(a)]	22.95	21.03	26.52
NGL as % of total production	13	12	9
Natural gas production (in bcf)	282	271	273
Average realized natural gas price ($/mcf)[(a)]	2.09	2.45	2.26
Natural gas as % of total production	71	72	73
Production expenses ($/boe)	(4.47)	(4.46)	(4.55)
Production taxes ($/boe)	(0.94)	(1.14)	(0.99)
General and administrative costs ($/boe)[(b)]	(0.72)	(1.25)	(1.71)
Share-based compensation ($/boe)	(0.18)	(0.18)	(0.21)
DD&A of natural gas and liquids properties ($/boe)	(10.31)	(10.45)	(10.52)
DD&A of other assets ($/boe)	(0.55)	(1.25)	(1.28)
Interest expense ($/boe)[(a)]	(0.16)	(0.92)	(0.65)
Marketing, gathering and compression net margin ($ in millions)[(c)]	(7)	1	23
Oilfield services net margin ($ in millions)[(c)]	—	69	38
Operating cash flow ($ in millions)[(d)]	1,293	1,269	1,412
Operating cash flow ($/boe)	19.37	20.07	22.79
Adjusted ebitda ($ in millions)[(e)]	1,236	1,277	1,325
Adjusted ebitda ($/boe)	18.52	20.20	21.38
Net income available to common stockholders ($ in millions)	169	145	156
Earnings per share – diluted ($)	0.26	0.22	0.24
Adjusted net income available to common stockholders ($ in millions)[(f)]	251	235	282
Adjusted earnings per share – diluted ($)	0.38	0.36	0.43
Total capital expenditures ($ in millions)	1,351	1,315	1,461
Capitalized interest ($ in millions)	170	155	195

(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 share-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 16.
(f) Defined as net income available to common stockholders, as adjusted to remove the effects of certain items detailed on Page 12.

2014 Third Quarter Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday, November 5, 2014, at 9:00 am EST. The telephone number to access the conference call is **913-312-1469** or toll-free **888-601-3877**. The passcode for the call is **2873261**. We encourage those who would like to participate in the call to place calls between 8:50 and 9:00 am EST. For those unable to participate in the live conference call, a replay will be available for audio playback at 2:00 pm EST on Wednesday, November 5, 2014, and will run through 2:00 pm EST on Wednesday, November 19, 2014. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **2873261**. 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.

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 natural gas and oil 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 asset 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 2013 annual report on Form 10-K filed with the U.S. Securities and Exchange Commission on February 27, 2014. These risk factors include the volatility of natural gas, oil and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values; the availability of capital on an economic basis, including through planned asset sales, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas, oil 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; hedging activities resulting in lower prices realized on natural gas, oil and

NGL sales; the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species; a deterioration in general economic, business or industry conditions having a material adverse effect on our results of operations, liquidity and financial condition; oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow; adverse developments and losses in connection with pending or future litigation and regulatory proceedings, and the adequacy of our provision for legal contingencies; cyber attacks adversely impacting our operations; and an interruption at our headquarters that adversely affects our business.

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. Further, the timing of and amount of proceeds from future asset sales, which are subject to changes in market conditions and other factors beyond our control, will affect our ability to further reduce financial leverage and complexity. In particular, we caution you that our October 2014 purchase and sale agreement with Southwestern Energy Company, in which we agreed to sell certain assets in the Marcellus Shale and Utica Shale for approximately $5.375 billion, is subject to closing conditions, including third-party consents and waiver of participation rights. 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		**Nine Months Ended**	
	September 30,		**September 30,**	
	2014	**2013**	**2014**	**2013**
REVENUES:				
Natural gas, oil and NGL	$ 2,341	$ 1,586	$ 5,812	$ 5,444
Marketing, gathering and compression	3,362	3,032	9,543	6,871
Oilfield services	—	249	546	650
Total Revenues	5,703	4,867	15,901	12,965
OPERATING EXPENSES:				
Natural gas, oil and NGL production	298	282	868	877
Production taxes	62	62	185	173
Marketing, gathering and compression	3,369	3,009	9,515	6,781
Oilfield services	—	211	431	543
General and administrative	60	120	229	336
Restructuring and other termination costs	(14)	63	12	203
Provision for legal contingencies	100	—	100	—
Natural gas, oil and NGL depreciation, depletion and	688	652	1,977	1,945

amortization				
Depreciation and amortization of other assets	37	79	194	234
Impairments of fixed assets and other	15	85	75	343
Net gains on sales of fixed assets	(86)	(132)	(201)	(290)
Total Operating Expenses	4,529	4,431	13,385	11,145
INCOME FROM OPERATIONS	1,174	436	2,516	1,820
OTHER INCOME (EXPENSE):				
Interest expense	(17)	(40)	(82)	(164)
Losses on investments	(27)	(22)	(72)	(36)
Net (gain) loss on sales of investments	—	3	67	(7)
Losses on purchases of debt	—	—	(195)	(70)
Other income (expense)	(1)	10	12	18
Total Other Expense	(45)	(49)	(270)	(259)
INCOME BEFORE INCOME TAXES	1,129	387	2,246	1,561
INCOME TAX EXPENSE:				
Current income taxes	2	7	10	9
Deferred income taxes	435	140	849	585
Total Income Tax Expense	437	147	859	594
NET INCOME	692	240	1,387	967
Net income attributable to noncontrolling interests	(30)	(38)	(110)	(127)
NET INCOME ATTRIBUTABLE TO CHESAPEAKE	662	202	1,277	840
Preferred stock dividends	(43)	(43)	(128)	(128)
Redemption of preferred shares of a subsidiary	(447)	—	(447)	(69)
Earnings allocated to participating securities	(3)	(3)	(15)	(14)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	$ 169	$ 156	$ 687	$ 629
EARNINGS PER COMMON SHARE:				
Basic	$ 0.26	$ 0.24	$ 1.04	$ 0.96
Diluted	$ 0.26	$ 0.24	$ 1.04	$ 0.96
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	660	656	659	654
Diluted	660	656	659	654

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

	September 30, 2014	**December 31, 2013**
Cash and cash equivalents	$ 90	$ 837
Other current assets	3,039	2,819
Total Current Assets	3,129	3,656
Property and equipment, (net)	36,652	37,134
Other assets	737	992
Total Assets	$ 40,518	$ 41,782
Current liabilities	$ 5,602	$ 5,515
Long-term debt, net of discounts	11,592	12,886
Other long-term liabilities	1,408	1,834
Deferred income tax liabilities	4,285	3,407
Total Liabilities	22,887	23,642

Preferred stock	3,062	3,062
Noncontrolling interests	1,311	2,145
Common stock and other stockholders' equity	13,258	12,933
Total Equity	17,631	18,140
Total Liabilities and Equity	$ 40,518	$ 41,782
Common Shares Outstanding (in millions)	663	664

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

	September 30, 2014	December 31, 2013
Total debt, net of unrestricted cash	$ 11,502	$ 12,049
Preferred stock	3,062	3,062
Noncontrolling interests[a]	1,311	2,145
Common stock and other stockholders' equity	13,258	12,933
Total	$ 29,133	$ 30,189
Total debt to capitalization ratio	39 %	40 %

[a]Includes third-party ownership as follows:

CHK Cleveland Tonkawa, L.L.C.	$ 1,015	$ 1,015
Chesapeake Granite Wash Trust	290	314
Other	6	9
CHK Utica, L.L.C.	—	807
Total	$ 1,311	$ 2,145

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Production:				
Natural gas (bcf)	282.0	273.3	813.4	824.1
Oil (mmbbl)	10.9	11.0	31.1	30.9
NGL (mmbbl)	8.8	5.4	24.1	15.0
Oil equivalent (mmboe)	66.8	62.0	190.7	183.3
Natural Gas, Oil and NGL Sales ($ in millions):				
Natural gas sales	$ 569	$ 581	$ 2,324	$ 1,932
Natural gas derivatives – realized gains (losses)[a]	19	37	(221)	(7)

Natural gas derivatives – unrealized gains (losses)[a]	166	6	125	74
Total Natural Gas Sales	754	624	2,228	1,999
Oil sales	1,005	1,115	2,933	2,975
Oil derivatives – realized gains (losses)[a]	(77)	(99)	(288)	(89)
Oil derivatives – unrealized gains (losses)[a]	456	(197)	354	163
Total Oil Sales	1,384	819	2,999	3,049
NGL sales	203	143	585	396
Total NGL Sales	203	143	585	396
Total Natural Gas, Oil and NGL Sales	$2,341	$1,586	$5,812	$5,444
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$2.02	$2.12	$2.86	$2.34
Oil ($ per bbl)	$91.87	$101.08	$94.28	$96.40
NGL ($ per bbl)	$22.95	$26.52	$24.31	$26.35
Oil equivalent ($ per boe)	$26.62	$29.67	$30.63	$28.94
Average Sales Price – including realized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$2.09	$2.26	$2.59	$2.34
Oil ($ per bbl)	$84.81	$92.09	$85.04	$93.51
NGL ($ per bbl)	$22.95	$26.52	$24.31	$26.35
Oil equivalent ($ per boe)	$25.74	$28.67	$27.96	$28.41
Interest Expense ($ in millions):				
Interest[b]	$15	$43	$132	$113
Derivatives – realized (gains) losses[c]	(4)	(3)	(9)	(6)
Derivatives – unrealized (gains) losses[c]	6	—	(41)	57
Total Interest Expense	$17	$40	$82	$164

(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:	**September 30, 2014**	**September 30, 2013**
Beginning cash	$ 1,462	$ 677

Cash provided by operating activities	1,184	1,381
Cash flows from investing activities:		
Drilling and completion costs on proved and unproved properties[(a)]	(1,191)	(1,303)
Acquisition of proved and unproved properties[(b)]	(651)	(266)
Sale of proved and unproved properties	459	885
Geological and geophysical costs	2	(8)
Cash paid to purchase leased rigs and compressors	(52)	(1)
Additions to other property and equipment	(25)	(132)
Proceeds from sales of other assets	251	337
Additions to investments	(9)	(4)
Proceeds from sales of investments	—	13
Other	35	7
Total cash provided by (used in) investing activities	(1,181)	(472)
Cash used in financing activities	(1,375)	(599)
Change in cash and cash equivalents	(1,372)	310
Ending cash	$ 90	$ 987

(a) Includes capitalized interest of $9 million and $15 million for the three months ended September 30, 2014 and 2013, respectively.

(b) Includes capitalized interest of $135 million and $176 million for the three months ended September 30, 2014 and 2013, respectively.

NINE MONTHS ENDED:	**September 30, 2014**	**September 30, 2013**
Beginning cash	$ 837	$ 287
Cash provided by operating activities	3,805	3,586
Cash flows from investing activities:		
Drilling and completion costs on proved and unproved properties[(a)]	(3,167)	(4,435)
Acquisition of proved and unproved properties[(b)]	(999)	(763)
Sale of proved and unproved properties	699	2,742
Geological and geophysical costs	(18)	(36)
Cash paid to purchase leased rigs and compressors	(474)	(4)
Additions to other property and equipment	(201)	(635)
Proceeds from sales of other assets	964	796
Additions to investments	(14)	(8)
Proceeds from sales of investments	239	115
Other	33	181
Total cash used in investing activities	(2,938)	(2,047)
Cash used in financing activities	(1,614)	(839)
Change in cash and cash equivalents	(747)	700
Ending cash	$ 90	$ 987

(a) Includes capitalized interest of $30 million and $47 million for the nine months ended September 30, 2014 and 2013, respectively.

(b) Includes capitalized interest of $433 million and $571 million for the nine months ended

September 30, 2014 and 2013, respectively.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS
($ in millions, except per share data)
(unaudited)

THREE MONTHS ENDED:	September 30, 2014	June 30, 2014	September 30, 2013
Net income available to common stockholders	$ 169	$ 145	$ 156
Adjustments, net of tax[a]:			
Unrealized (gains) losses on derivatives	(384)	(19)	118
Restructuring and other termination costs	(9)	20	39
Impairments of fixed assets and other	9	25	55
Net gains on sales of fixed assets	(54)	(57)	(82)
Impairments of investments	—	3	—
Net gains on sales of investments	—	—	(2)
Losses on purchases of debt and extinguishment of other financing	—	120	—
Provision for legal contingencies	62	—	—
Other	11	(2)	(2)
Redemption of preferred shares of a subsidiary[a]	447	—	—
Adjusted net income available to common stockholders[b]	$ 251	$ 235	$ 282
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	3	3	3
Total adjusted net income attributable to Chesapeake	$ 297	$ 281	$ 328
Weighted average fully diluted shares outstanding (in millions)[c]	776	776	765
Adjusted earnings per share assuming dilution[b]	$ 0.38	$ 0.36	$ 0.43

(a) All adjustments to net income available to common stockholders reflected net of tax other than the redemption of preferred shares of a subsidiary.

(b) 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 accounting principles generally accepted in the United States (GAAP) because:

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

(c) 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)

NINE MONTHS ENDED:	**September 30, 2014**	**September 30, 2013**
Net income available to common stockholders	$ 687	$ 629
Adjustments, net of tax[(a)]:		
Unrealized gains on derivatives	(324)	(112)
Restructuring and other termination costs	7	126
Impairments of fixed assets and other	46	215
Net gains on sales of fixed assets	(125)	(180)
Impairments of investments	3	6
Net (gains) losses on sales of investments	(42)	4
Losses on purchases of debt and extinguishment of other financing	121	44
Provision for legal contingencies	62	—
Other	5	(2)
Redemption of preferred shares of a subsidiary[(a)]	447	69
Adjusted net income available to common stockholders[(b)]	$ 887	$ 799
Preferred stock dividends	128	128
Earnings allocated to participating securities	15	14
Total adjusted net income attributable to Chesapeake	$ 1,030	$ 941
Weighted average fully diluted shares outstanding (in millions)[(c)]	776	763
Adjusted earnings per share assuming dilution[(b)]	$ 1.33	$ 1.23

(a) All adjustments to net income available to common stockholders reflected net of tax other than the redemption of preferred shares of a subsidiary.

(b) 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 accounting principles generally accepted in the United States (GAAP) because:

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

(c) 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:	September 30, 2014	June 30, 2014	September 30, 2013
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,184	$ 1,352	$ 1,381
Changes in assets and liabilities	109	(83)	31
OPERATING CASH FLOW[(a)]	$ 1,293	$ 1,269	$ 1,412

THREE MONTHS ENDED:	September 30, 2014	June 30, 2014	September 30, 2013
NET INCOME	$ 692	$ 230	$ 240
Interest expense	17	27	40
Income tax expense	437	141	147
Depreciation and amortization of other assets	37	79	79
Natural gas, oil and NGL depreciation, depletion and amortization	688	661	652
EBITDA[(b)]	$ 1,871	$ 1,138	$ 1,158

THREE MONTHS ENDED:	September 30, 2014	June 30, 2014	September 30, 2013
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,184	$ 1,352	$ 1,381
Changes in assets and liabilities	109	(83)	31
Interest expense, net of unrealized gains (losses) on derivatives	11	58	40
Natural gas, oil and NGL derivative gains (losses), net	564	(213)	(247)
Cash payments on natural gas, oil and NGL derivative settlements, net	34	150	20
Share-based compensation	(19)	(20)	(22)
Restructuring and other termination costs	42	(33)	(60)
Impairments of fixed assets and other	(15)	(39)	(59)
Net gains on sales of fixed assets	86	93	132
Earnings (losses) on investments	(27)	(24)	(30)
Provision for legal contingencies	(100)	—	—
Losses on purchases of debt and extinguishment of			

other financing	—	(61)	(20)
Other items	2	(42)	(8)
EBITDA[(b)]	$ 1,871	$ 1,138	$ 1,158

(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 a natural gas and oil 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 natural gas and oil 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)

NINE MONTHS ENDED:	**September 30, 2014**	**September 30, 2013**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 3,805	$ 3,586
Changes in assets and liabilities	348	372
OPERATING CASH FLOW[(a)]	$ 4,153	$ 3,958

NINE MONTHS ENDED:	**September 30, 2014**	**September 30, 2013**
NET INCOME	$ 1,387	$ 967
Interest expense	82	164
Income tax expense	859	594
Depreciation and amortization of other assets	194	234
Natural gas, oil and NGL depreciation, depletion and amortization	1,977	1,945
EBITDA[(b)]	$ 4,499	$ 3,904

NINE MONTHS ENDED:	**September 30,**	**September 30,**

	2014	2013
CASH PROVIDED BY OPERATING ACTIVITIES	$ 3,805	$ 3,586
Changes in assets and liabilities	348	372
Interest expense, net of unrealized gains (losses) on derivatives	123	107
Natural gas, oil and NGL derivative gains (losses), net	(30)	141
Cash payments on natural gas, oil and NGL derivative settlements, net	352	61
Share-based compensation	(59)	(78)
Restructuring and other termination costs	18	(164)
Impairments of fixed assets and other	(44)	(317)
Net gains on sales of fixed assets	201	290
Provision for legal contingencies	(100)	—
Losses on investments	(72)	(40)
Net gains (losses) on sales of investments	67	(7)
Losses on purchases of debt and extinguishment of other financing	(61)	(37)
Other items	(49)	(10)
EBITDA[(b)]	$ 4,499	$ 3,904

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 a natural gas and oil company's ability to generate cash which 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 natural gas and oil 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:	**September 30, 2014**	**June 30, 2014**	**September 30, 2013**
EBITDA	$ 1,871	$ 1,138	$ 1,158
Adjustments:			
Unrealized (gains) losses on natural gas, oil and NGL derivatives	(622)	—	191

Restructuring and other termination costs	(14)	33	63
Impairments of fixed assets and other	15	40	89
Net gains on sales of fixed assets	(86)	(93)	(132)
Impairments of investments	—	5	—
Net gains on sales of investments	—	—	(3)
Losses on purchases of debt and extinguishment of other financing	—	195	—
Provision for legal contingencies	100	—	—
Net income attributable to noncontrolling interests	(30)	(39)	(38)
Other	2	(2)	(3)
Adjusted EBITDA[(a)]	$ 1,236	$ 1,277	$ 1,325

NINE MONTHS ENDED:	**September 30, 2014**	**September 30, 2013**
EBITDA	$ 4,499	$ 3,904
Adjustments:		
Unrealized gains on natural gas, oil and NGL derivatives	(479)	(238)
Restructuring and other termination costs	12	203
Impairments of fixed assets and other	75	347
Net gains on sales of fixed assets	(201)	(290)
Impairment of investments	5	10
Net (gains) losses on sales of investments	(67)	7
Losses on purchases of debt and extinguishment of other financing	195	70
Provision for legal contingencies	100	—
Net income attributable to noncontrolling interests	(110)	(127)
Other	—	(3)
Adjusted EBITDA[(a)]	$ 4,029	$ 3,883

(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 natural gas and oil 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.

SCHEDULE "A" MANAGEMENT'S OUTLOOK AS OF NOVEMBER 5, 2014

Chesapeake periodically provides management guidance on certain factors that affect the company's future financial performance. The primary changes from the company's August 6, 2014 Outlook are in ***italicized bold*** below.

Year Ending

	12/31/2014
Production (adjusted for asset sales)[(a)]:	
Liquids	29 – 33%
Oil	11 – 15%
NGL[(b)]	63 – 68%
Natural gas	4 – 6%
Total Adjusted Production	9 – 12%
Daily Equivalent Rate - mboe	***695 – 705***
NYMEX Price[(c)] (for calculation of realized hedging effects only):	
Oil - $/bbl	***$97.21***
Natural gas - $/mcf	***$4.41***
Estimated Realized Hedging Effects[(d)] (based on assumed NYMEX prices above):	
Oil - $/bbl	***($7.31)***
Natural gas - $/mcf	***($0.19)***
Estimated Basis/Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Oil - $/bbl	$5.00 – 7.00
NGL - $/bbl	$72.00 – 76.00
Natural gas - $/mcf	***$1.80 – 1.90***
Operating Costs per Boe of Projected Production:	
Production expense	$4.25 – 4.75
Production taxes	$0.90 – 1.00
General and administrative[(e)]	$1.20 – 1.30
Share-based compensation (noncash)	$0.15 – 0.20
DD&A of natural gas and liquids assets	$10.00 – 11.00
Depreciation of other assets	$0.90 – 1.00
Interest expense[(f)]	$0.65 – 0.75
Other ($ millions):	
Marketing, gathering and compression net margin[(g)]	***$25 – 50***
Net income attributable to noncontrolling interests and other[(h)]	***($115 – 145)***
Book Tax Rate	***38%***
Weighted Average Shares Outstanding (in millions):	
Basic	657 – 661
Diluted	775 – 779
Operating Cash Flow before Changes in Assets and Liabilities ($ in millions) [(c)(i)]	***$5,250 – 5,450***
Total Capital Expenditures ($ in millions)[(j)]	$5,000 – 5,400
Capitalized interest, dividends and distributions ($ in millions)	***$1,085 – 1,135***

a) Growth ranges based on 2013 production of 604 mboe/day adjusted for asset sales in 2013 and 2014, and excludes the previously announced Marcellus and Utica asset sale.

b) Assumes ethane recovery in the Utica and southern Marcellus to fulfill Chesapeake’s pipeline commitments, no ethane recovery in the Rockies and partial ethane recovery in the Mid-Continent and Eagle Ford.

c) Assumes NYMEX prices on open contracts of $90.00 per bbl and $4.00 per mcf. NYMEX natural gas and oil prices have been updated for actual contract prices through October and September, respectively.

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

e) Excludes expenses associated with share-based compensation and restructuring and other termination costs.

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

g) Includes revenue and operating expenses and excludes depreciation and amortization of other assets

h) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust, CHK

Utica, L.L.C. and CHK Cleveland Tonkawa, L.L.C. CHK Utica became wholly owned on July 29, 2014 when the company purchased CHK Utica preferred shares held by third parties.

i) A non-GAAP financial measure. We are unable to provide reconciliation to projected cash provided by operating activities, the most comparable GAAP measure, because of uncertainties associated with projecting future changes in assets and liabilities.

j) Includes capital expenditures for drilling and completion, unproved properties, geological and geophysical costs and other property, plant and equipment and excludes capitalized interest and our August 2014 exchange of northern PRB properties and approximately $450 million for RKI's southern PRB properties.

Natural Gas, Oil and NGL Hedging Activities

Chesapeake enters into natural gas, oil 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 and year-end derivative positions and accounting for natural gas, oil and NGL derivatives.

As of November 1, 2014, the company had downside protection on approximately 72% of its remaining projected 2014 natural gas production at an average price of $4.12 per thousand cubic feet of natural gas. Approximately 64% of the company's remaining projected 2014 oil production had downside protection at an average price of $94.22 per bbl.

The company’s natural gas hedging positions as of November 1, 2014 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)
Q4 2014	112	$ 4.09	$ (21)
Total 2015	112	***$ 4.35***	$ (131)
Total 2016 – 2022	0	-	$ (187)

Natural Gas Three-Way Collars

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q4 2014	71	$ 3.49	$ 4.11	$ 4.37
Total 2015	207	$ 3.37	$ 4.29	$ 4.51

Natural Gas Collars

	Open Collars	Avg. NYMEX	Avg. NYMEX

	(bcf)	Bought Put Price	Sold Call Price
Q4 2014	11	$ 4.50	$ 5.24

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 minus
Q4 2014	***34***	***(0.12)***
Total 2015	***52***	***$ 0.55***
Total 2016 - 2022	8	$ (1.02)

The company's crude oil hedging positions as of November 1, 2014 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 (Losses) from Closed Trades and Premiums for Call Options ($ in millions)
Q4 2014	7,197	$ 94.22	$ (49)
Total 2015	12,457	$ 94.58	***$ 236***
Total 2016 – 2022	0	—	$ 117

Crude Oil Three-Way Collars

	Open Collars (mbbls)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Ceiling Price
Total 2015	4,380	$ 80.00	$ 90.00	$ 98.94

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price
Q4 2014	626	$ 83.53

Total 2015	**11,606**	**$ 92.93**
Total 2016 – 2017	24,220	$ 100.07

Crude Oil Basis Protection Swaps

	Volume (mbbls)	Avg. NYMEX plus
Q4 2014	92	$ 6.00

Source: Chesapeake Energy Corporation

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