NEWS RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2014 Full Year and Fourth Quarter

Announces 2015 Total Planned Capital Expenditures

OKLAHOMA CITY--(BUSINESS WIRE)--Feb. 25, 2015-- Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operational results for the 2014 full year and fourth quarter and announced details of its 2015 Outlook and capital expenditure program. Highlights include:

- ***2014 adjusted net income of $1.49 per fully diluted share and 2014 adjusted ebitda of $4.945 billion***
- ***Average 2014 production of approximately 706,000 boe per day, an increase of 9% year over year, adjusted for asset sales***
- ***Planned 2015 total capital expenditures ranging from $4.0 to $4.5 billion***
- ***Projected 2015 production growth of 3 – 5%, adjusted for asset sales***

Doug Lawler, Chesapeake's Chief Executive Officer, said, "2014 was a year of accomplishments for Chesapeake. Because of these accomplishments and the progress we have made as a company in 2014, Chesapeake is well positioned to remain strong and flexible in 2015. We have taken and continue to take appropriate steps not only to weather the current difficult commodity price environment we face today, but to thrive in it. Chesapeake became a much stronger company in 2014, and we are looking forward to becoming even stronger in 2015."

2015 Capital Program and Production Outlook

Chesapeake is budgeting total capital expenditures (including capitalized interest) of $4.0 – $4.5 billion for 2015. Using the midpoint of the range, this represents a 26% reduction from the company's 2014 capital expenditures before acquisitions of $5.8 billion, and a 37% reduction from the company's 2014 total capital expenditures of approximately $6.7 billion (reconciled in the "Capital Spending and Cost Overview" section below). The company is targeting 2015 production of 235 – 240 million barrels of oil equivalent (mmboe), or average daily production of 645 – 655 thousand barrels of oil equivalent (mboe), which represents 3 – 5% production growth after adjusting for 2014 asset sales. Of the 2015 projected production, approximately 39 – 40 mmboe is estimated to be crude oil, 1,035 – 1,055 billion cubic feet (bcf) natural gas and 23 – 24 mmboe natural gas liquids (NGL).

Chesapeake plans to operate 35 – 45 rigs in 2015, which represents the company's lowest operated rig activity level since 2004 and a decrease of approximately 38% (using the midpoint of the range) from an average of 64 rigs in 2014. The company intends to spud approximately 790 gross operated wells and connect to sales approximately 800 gross operated wells in 2015, a decrease from approximately 1,175 and 1,150 wells, respectively, in 2014. The table below compares the capital and rig counts allocated to the company’s operating areas for 2015 and 2014:

	2015E D&C Capex Allocation	2014 D&C Capex Allocation	2015E Avg. Operated Rigs	2014 Avg. Operated Rigs
Eagle Ford	35%	40%	12 – 14	20
Utica	25%	10%	3 – 5	8
Haynesville	13%	8%	7 – 8	8
Powder River Basin: Niobrara & Upper Cretaceous	10%	5%	3 – 4	4
Mid-Continent North: Mississippian Lime	5%	7%	7 – 8	9
Mid-Continent South	5%	8%	1 – 2	5
Marcellus	5%	11%	1 – 2	5
Other[(a)]	2%	11%	1 – 2	5
Totals	100%	100%	35 – 45	64

(a) For 2014, includes Marcellus South, Barnett Shale and exploration wells.

2014 Full-Year Results

For the 2014 full year, Chesapeake reported net income available to common stockholders of $1.273 billion, or $1.87 per fully diluted share. Items typically excluded by securities analysts in their earnings estimates increased net income available to common stockholders for the 2014 full year by approximately $316 million and are presented on Page 14 of this release. The primary component of this increase was unrealized gains on the company's oil and natural gas commodity derivatives, partially offset by the redemption of all the outstanding preferred shares of a subsidiary. Adjusting for these items, 2014 full-year adjusted net income available to common stockholders was $957 million, or $1.49 per fully diluted share, compared to adjusted net income available to common stockholders of $965 million, or $1.50 per fully diluted share, in the 2013 full year.

Adjusted ebitda was $4.945 billion for the 2014 full year, compared to $5.016 billion for the 2013 full year. Operating cash flow, which is defined as cash flow provided by operating activities before changes in assets and liabilities, was $5.026 billion for the 2014 full year, compared to $4.958 billion for the 2013 full year.

Adjusted net income available to common stockholders, operating cash flow, ebitda and adjusted ebitda are non-GAAP financial measures. Reconciliations of these measures to comparable financial measures calculated in accordance with generally accepted accounting principles are provided on pages 13 – 17 of this release.

Chesapeake’s daily production for the 2014 full year averaged 706,300 barrels of oil equivalent (boe), a year-over-year increase of 9%, adjusted for asset sales. Average daily production consisted of approximately 115,800 barrels (bbls) of oil, 3.0 bcf of natural gas and 90,500 bbls of NGL. Adjusted for asset sales, 2014 full-year average daily oil production increased 7%, average daily natural gas production increased 6% and average daily NGL production increased 42%.

2014 Fourth Quarter Results

For the 2014 fourth quarter, Chesapeake reported net income available to common stockholders of $586 million, or $0.81 per fully diluted share. Items typically excluded by securities analysts in their earnings estimates increased 2014 fourth quarter net income by approximately $552 million on an after-tax basis. The primary component of this increase was unrealized gains on oil and natural gas commodity derivatives.

Adjusting for these items, 2014 fourth quarter net income available to common stockholders was $34 million, or $0.11 per fully diluted share, which compares to adjusted net income available to common stockholders of $161 million, or $0.27 per fully diluted share, in the 2013 fourth quarter.

For the 2014 fourth quarter, Chesapeake reported adjusted ebitda of $916 million, compared to $1.132 billion in the 2013 fourth quarter. Operating cash flow was $873 million in the 2014 fourth quarter, compared to $995 million in the 2013 fourth quarter. The quarter-over-quarter decreases in adjusted ebitda and operating cash flow were primarily the result of lower realized oil, natural gas and NGL prices, partially offset by higher production volumes.

Chesapeake's daily production for the 2014 fourth quarter averaged approximately 729,000 boe, a year-over-year increase of 12%, adjusted for asset sales. Average daily production in the 2014 fourth quarter consisted of approximately 121,200 bbls of oil, 3.1 bcf of natural gas and 97,600 bbls of NGL, which represent year-over-year increases of 7%, 9% and 40% respectively, adjusted for asset sales.

Strategic Transactions and Asset Sales Update

In the 2014 fourth quarter, the company received approximately $5.1 billion of net proceeds from asset sales, most of which was from the sale of certain assets in the southern Marcellus Shale and a portion of the eastern Utica Shale assets that closed in December 2014. Also in the 2014 fourth quarter, the company entered into a new five-year $4.0 billion senior unsecured syndicated revolving credit facility. The new unsecured facility has investment grade-like terms and allowed Chesapeake to release nearly $6.0 billion of proved reserve-based collateral.

Capital Spending and Cost Overview

Chesapeake's drilling and completion capital expenditures during the 2014 full year were approximately $4.5 billion, and capital expenditures for the acquisition of unproved properties, geological and geophysical costs, and other property, plant and equipment were approximately $669 million, for a total of approximately $5.1 billion, compared to the company's forecasted range of $5.0 – $5.4 billion. In addition, during 2014 the company invested approximately $499 million to repurchase leased rigs and compressors as part of its strategic initiative to reduce complexity and future commitments, as well as to facilitate asset sales and the spin-off of its oilfield services business. The company also invested approximately $450 million as part of an exchange of properties in the Powder River Basin. Total capital investments, including capitalized interest of $637 million, were approximately $6.7 billion in 2014, compared to approximately $7.8 billion in 2013, and is reconciled below. Chesapeake's total capital expenditures were approximately $1.8 billion in the 2014 fourth quarter compared to approximately $2.1 billion in the 2013 fourth quarter.

$ in millions	**2013**		**2014**		**2015**
Type of Cost	**Q4**	**FY**	**Q4**	**FY**	**Outlook**
Drilling and completion costs	$ 1,151	$ 5,466	$ 1,370	$ 4,470	
Other exploration and development costs and PP&E	478	1,231	252	669	
Subtotal planned capital spending	**$ 1,629**	**$ 6,697**	**$ 1,622**	**$ 5,139**	**$3,500 – 4,000**
Capitalized interest	182	815	134	637	500
PRB property exchange	—	—	—	450	
Sale leasebacks	262	266	25	499	
Total capital spending	**$ 2,073**	**$ 7,778**	**$ 1,781**	**$ 6,725**	**$4,000 – 4,500**

Chesapeake spud a total of 308 gross wells and connected 311 gross wells to sales during the 2014 fourth quarter, compared to 239 gross wells spud and 260 gross wells connected to sales during the 2014 third quarter.

Chesapeake's focus on cost discipline continued to generate reductions in costs associated with production and general and administrative (G&A) expenses. Average production expenses during the 2014 full year were $4.69 per boe, a decrease of 1% year over year. G&A expenses (including stock-based compensation) during the 2014 full year were $1.25 per boe, a decrease of 33% year over year.

Average production expenses during the 2014 fourth quarter were $5.07, an increase of 10% from the 2013 fourth quarter. G&A expenses (including stock-based compensation) during the 2014 fourth quarter were $1.38 per boe, a decrease of 30% from the 2013 fourth quarter.

A summary of the company’s guidance for 2015 is provided in the Outlook dated February 25, 2015, attached to this release as Schedule "A” beginning on Page 18.

Total Proved Reserves

The company's December 31, 2014, proved reserves were 2.469 billion boe, an increase of 5% compared to year-end 2013 before acquisitions and divestitures. In 2014, Chesapeake increased its proved reserves by 448 mmboe for extensions and discoveries and 14 mmboe from acquisitions. The additions were offset by 362 mmboe as the result of divestitures, 51 mmboe of net negative reserve revisions and production of 258 mmboe. Chesapeake's proved developed reserves as a percentage of total proved reserves increased to 75% as of December 31, 2014, compared to 68% as of December 31, 2013. Additional information on reserves changes can be found on Page 10.

Operations Update

As described below, Chesapeake continues to improve on its capital efficiency, cycle times and well cost reductions.

Southern Division

Eagle Ford Shale (South Texas): Eagle Ford net production averaged approximately 106 mboe per day (230 gross operated mboe per day) during the 2014 fourth quarter, an increase of 4% sequentially. The 2014 average completed well cost (January – October) was approximately $6.1 million with an average completed lateral length of 5,900 feet and 19 frac stages, compared to an average completed well cost of $6.9 million in 2013 with an average completed lateral length of 5,850 feet and 18 frac stages. Wells in various stages of completion or waiting on pipeline in the area have increased to 158 as of December 31, 2014, compared to 109 wells at December 31, 2013. The average peak production rate of the 123 wells that commenced first production in the Eagle Ford during the 2014 fourth quarter was approximately 850 boe per day.

Haynesville Shale (Northwest Louisiana): Haynesville Shale net production averaged approximately 592 million cubic feet of natural gas equivalent (mmcfe) per day (910 gross operated mmcfe per day) during the 2014 fourth quarter, an increase of 5% sequentially. The 2014 average completed well cost (January – October) was approximately $8.4 million with an average completed lateral length of 4,900 feet and 13 frac stages, compared to an average completed well cost of $8.9 million in 2013 with an average completed lateral length of 4,400 feet and 18 frac stages. The average peak production rate of the 18 wells that commenced first production in the Haynesville during the 2014 fourth quarter was approximately 13.4 mmcfe per day.

Mid-Continent North: Mississippian Lime (Northern Oklahoma): Mississippian Lime net production averaged approximately 28 mboe per day (72 gross operated mboe per day) during the 2014 fourth quarter, an increase of 4% sequentially. The 2014 average completed well cost (January – October) was approximately $3.1 million with an average completed lateral length of 4,500 feet, compared to an average completed well cost of $3.5 million in 2013 with an average completed lateral length of 4,500 feet. The average peak production rate of the 42 wells that commenced first production in the Mississippian Lime during the 2014 fourth quarter was approximately 730 boe per day.

Northern Division

Utica Shale (Eastern Ohio): Utica net production averaged approximately 100 mboe per day (180 gross operated mboe per day) during the 2014 fourth quarter, an increase of 17% sequentially. The 2014 average completed well cost (January – October) was approximately $6.6 million with an average completed lateral length of 6,000 feet and 27 frac stages, compared to an average completed well cost of $6.7 million in 2013 with an average completed lateral length of 5,150 feet and 17 frac stages. Wells in various stages of completion or waiting on pipeline in the area decreased to 166 as of December 31, 2014, compared to 195 at December 31, 2013. The average peak production rate of the 51 wells that commenced first production in the Utica during the 2014 fourth quarter was approximately 1,280 boe per day.

Marcellus Shale (Northern Pennsylvania): Northern Marcellus net production averaged approximately 817 mmcfe per day (2.07 gross operated bcfe per day) during the 2014 fourth quarter, a decrease of 7% sequentially. The 2014 average completed well cost (January – October) was approximately $7.3 million with an average completed lateral length of 5,900 feet and 27 frac stages, compared to an average completed well cost of $7.9 million in 2013 with an average completed lateral length of 5,400 feet and 13 frac stages. Wells in various stages of completion or waiting on pipeline in the area increased to 117 as of December 31, 2014, compared to 112 at December 31, 2013. The average peak production rate of the 25 wells that commenced first production in the northern Marcellus during the 2014 fourth quarter was approximately 15.2 mmcfe per day.

Powder River Basin (PRB): Niobrara and Upper Cretaceous (Wyoming): PRB net production averaged approximately 18 mboe per day (27 gross operated mboe per day) during the 2014 fourth quarter, an increase of 20% sequentially, and, adjusted on an absolute basis to include the property exchange transaction with RKI Exploration & Production, an increase of 29% sequentially. The 2014 average completed well cost (January – October) was approximately $9.1 million per well with an average completed lateral length of 5,100 feet and 18 frac stages, compared to an average completed well cost of $10.1 million per well in 2013 with an average completed lateral length of 5,050 feet and 15 frac stages. Wells in various stages of completion or waiting on pipeline in the area decreased to 38 as of December 31, 2014, compared to 57 wells at December 31, 2013. The average peak production rate of the 13 wells that commenced first production in the Powder River Basin during the 2014 fourth quarter was approximately 1,670 boe per day.

Key Financial and Operational Results

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

	Three Months Ended			Full Year Ended	
	12/31/14	**09/30/14**	**12/31/13**	**12/31/14**	**12/31/13**
Oil equivalent production (in mmboe)	67.1	66.8	61.2	257.8	244.4
Oil production (in mmbbls)	11.2	10.9	10.2	42.3	41.1
Average realized oil price ($/bbl)(a)	76.40	84.81	89.58	82.76	92.53
Oil as % of total production	17	16	17	16	17
NGL production (in mmbbls)	9.0	8.8	5.9	33.1	20.9
Average realized NGL price ($/bbl)(a)	13.11	22.95	31.76	21.27	27.87
NGL as % of total production	13	13	9	13	8
Natural gas production (in bcf)	281.6	282.0	270.5	1,095.0	1,094.6
Average realized natural gas price ($/mcf)(a)	1.72	2.09	1.90	2.36	2.23
Natural gas as % of total production	70	71	74	71	75
Production expenses ($/boe)	(5.07)	(4.47)	(4.62)	(4.69)	(4.74)
Production taxes ($/boe)	(0.70)	(0.94)	(0.91)	(0.90)	(0.94)
General and administrative costs ($/boe)(b)	(1.23)	(0.72)	(1.79)	(1.07)	(1.62)
Stock-based compensation ($/boe)	(0.15)	(0.18)	(0.19)	(0.18)	(0.24)
DD&A of natural gas and liquids properties ($/boe)	(10.53)	(10.31)	(10.53)	(10.41)	(10.59)
DD&A of other assets ($/boe)	(0.56)	(0.55)	(1.32)	(0.90)	(1.28)
Interest expense ($/boe)(a)	(0.56)	(0.16)	(0.86)	(0.63)	(0.65)
Marketing, gathering and compression net margin ($ in millions)(c)	(39)	(7)	9	(11)	98
Oilfield services net margin ($ in millions)(c)	—	—	52	115	159
Operating cash flow ($ in millions)(d)	873	1,293	995	5,026	4,958
Operating cash flow ($/boe)	13.01	19.37	16.27	19.50	20.26
Adjusted ebitda ($ in millions)(e)	916	1,236	1,132	4,945	5,016
Adjusted ebitda ($/boe)	13.66	18.52	18.51	19.18	20.52
Net income available to common stockholders ($ in millions)	586	169	(159)	1,273	474
Earnings per share – diluted ($)	0.81	0.26	(0.24)	1.87	0.73
Adjusted net income available to common stockholders ($ in millions)(f)	34	251	161	957	965
Adjusted earnings per share – diluted ($)	0.11	0.38	0.27	1.49	1.50

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

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

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

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

(e) Defined as net income before interest expense, income taxes and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on Page 17.

(f) Defined as net income available to common stockholders, as adjusted to remove the effects of certain items detailed on Page 14.

2014 Full-Year and Fourth Quarter Financial and Operational Results Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday, February 25, 2015, 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, February 25, 2015, and will run through 2:00 pm EST on Wednesday, March 11, 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 **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 oil and natural gas assets onshore in the U.S. The company also owns substantial marketing and compression businesses. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and news releases.

This news release and the accompanying Outlook include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements other than statements of historical fact. They include statements that give our current expectations or forecasts of future events, production, production growth and well connection forecasts, estimates of operating costs, planned development drilling and expected drilling cost reductions, capital expenditures, expected efficiency gains, anticipated 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 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		**Year Ended**	
	December 31,		**December 31,**	
	2014	**2013**	**2014**	**2013**
REVENUES:				
Oil, natural gas and NGL	$ 2,369	$ 1,608	$ 8,180	$ 7,052
Marketing, gathering and compression	2,681	2,689	12,225	9,559
Oilfield services	—	244	546	895
Total Revenues	5,050	4,541	20,951	17,506
OPERATING EXPENSES:				
Oil, natural gas and NGL production	340	282	1,208	1,159
Production taxes	47	56	232	229
Marketing, gathering and compression	2,720	2,680	12,236	9,461
Oilfield services	—	193	431	736
General and administrative	93	121	322	457
Restructuring and other termination costs	(5)	45	7	248
Provision for legal contingencies	134	—	234	—
Oil, natural gas and NGL depreciation, depletion and amortization	706	644	2,683	2,589
Depreciation and amortization of other assets	38	80	232	314
Impairments of fixed assets and other	14	203	88	546
Net (gains) losses on sales of fixed assets	3	(12)	(199)	(302)
Total Operating Expenses	4,090	4,292	17,474	15,437
INCOME FROM OPERATIONS	960	249	3,477	2,069
OTHER INCOME (EXPENSE):				
Interest expense	(7)	(63)	(89)	(227)
Losses on investments	(7)	(189)	(80)	(226)
Net gain (loss) on sales of investments	—	—	67	(7)
Losses on purchases of debt	(2)	(123)	(197)	(193)
Other income	10	7	22	26
Total Other Expense	(6)	(368)	(277)	(627)
INCOME (LOSS) BEFORE INCOME TAXES	954	(119)	3,200	1,442
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	13	13	47	22
			1,097	

Deferred income taxes	273	(58)	[illegible]	526
Total Income Tax Expense (Benefit)	286	(45)	1,144	548
NET INCOME (LOSS)	668	(74)	2,056	894
Net income attributable to noncontrolling interests	(29)	(42)	(139)	(170)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	639	(116)	1,917	724
Preferred stock dividends	(43)	(43)	(171)	(171)
Redemption of preferred shares of a subsidiary	—	—	(447)	(69)
Earnings allocated to participating securities	(10)	—	(26)	(10)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 586	$ (159)	$ 1,273	$ 474
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.89	$ (0.24)	$ 1.93	$ 0.73
Diluted	$ 0.81	$ (0.24)	$ 1.87	$ 0.73
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	660	656	659	653
Diluted	773	656	772	653

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

	December 31, 2014	**December 31, 2013**
Cash and cash equivalents	$ 4,108	$ 837
Other current assets	3,360	2,819
Total Current Assets	7,468	3,656
Property and equipment, (net)	32,515	37,134
Other assets	768	992
Total Assets	$ 40,751	$ 41,782
Current liabilities	$ 5,863	$ 5,515
Long-term debt, net of discounts	11,154	12,886
Other long-term liabilities	1,344	1,834
Deferred income tax liabilities	4,185	3,407
Total Liabilities	22,546	23,642
Preferred stock	3,062	3,062
Noncontrolling interests	1,302	2,145
Common stock and other stockholders’ equity	13,841	12,933
Total Equity	18,205	18,140
Total Liabilities and Equity	$ 40,751	$ 41,782
Common Shares Outstanding (in millions)	663	664

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

	December 31,	**December 31,**

	2014	2013
Total debt, net of unrestricted cash	$ 7,427	$ 12,049
Preferred stock	3,062	3,062
Noncontrolling interests[a]	1,302	2,145
Common stock and other stockholders' equity	13,841	12,933
Total	$ 25,632	$ 30,189
Total net debt to capitalization ratio	29 %	40 %

[a] Includes third-party ownership as follows:

CHK Cleveland Tonkawa, L.L.C.	$ 1,015	$ 1,015
Chesapeake Granite Wash Trust	287	314
CHK Utica, L.L.C.	—	807
Other	—	9
Total	$ 1,302	$ 2,145

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
12 MONTHS ENDED DECEMBER 31, 2014
(unaudited)

	Mmboe[a]
Beginning balance, December 31, 2013	2,678
Production	(258)
Acquisitions	14
Divestitures	(362)
Revisions - changes to previous estimates	(78)
Revisions - price	27
Extensions and discoveries	448
Ending balance, December 31, 2014	2,469
Proved reserves growth rate before acquisitions and divestitures	5 %
Proved reserves growth rate after acquisitions and divestitures	(8)%
Proved developed reserves	1,864
Proved developed reserves percentage	75 %
PV-10 ($ in millions)[a]	$ 22,012

[a] Reserve volumes and PV-10 value estimated using SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices as of December 31, 2014, of $4.35 per mcf of natural gas and $94.98 per bbl of oil, before field differential adjustments.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF PV-10
($ in millions)
(unaudited)

	December 31,	December 31,

	2014	2013
Standardized measure of discounted future net cash flows	$ 17,133	$ 17,390
Discounted future cash flows for income taxes	4,879	4,286
Discounted future net cash flows before income taxes (PV-10)	$ 22,012	$ 21,676

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

The company’s PV-10 and standardized measure were calculated using the following prices, before field differentials: $4.35 per mcf of natural gas and $94.98 per bbl of oil as of December 31, 2014, and $3.67 per mcf of natural gas and $96.82 per bbl of oil as of December 31, 2013, before field differential adjustments.

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2014	**2013**	**2014**	**2013**
Net Production:				
Oil (mmbbl)	11.2	10.2	42.3	41.1
Natural gas (bcf)	281.6	270.5	1,095.0	1,094.6
NGL (mmbbl)	9.0	5.9	33.1	20.9
Oil equivalent (mmboe)	67.1	61.2	257.8	244.4
Oil, natural gas and NGL Sales ($ in millions):				
Oil sales	$ 749	$ 937	$ 3,682	$ 3,911
Oil derivatives – realized gains (losses)[a]	103	(19)	(185)	(108)
Oil derivatives – unrealized gains (losses)[a]	505	116	859	280
Total Oil Sales	1,357	1,034	4,356	4,083
Natural gas sales	453	498	2,777	2,430
Natural gas derivatives – realized gains (losses)[a]	30	17	(191)	9
Natural gas derivatives – unrealized gains (losses)[a]	411	(127)	535	(52)
Total Natural Gas Sales	894	388	3,121	2,387
NGL sales	118	186	703	582
Total NGL Sales	118	186	703	582
Total Oil, Natural Gas and NGL Sales	$ 2,369	$ 1,608	$ 8,180	$ 7,052
Average Sales Price – excluding gains (losses) on derivatives:				
Oil ($ per bbl)	$ 67.16	$ 91.46	$ 87.13	$ 95.17
Natural gas ($ per mcf)	$ 1.61	$ 1.84	$ 2.54	$ 2.22

NGL ($ per bbl)	$13.11	$31.76	$21.27	$27.87
Oil equivalent ($ per boe)	$19.68	$26.49	$27.78	$28.33

Average Sales Price – including realized gains (losses) on derivatives:

Oil ($ per bbl)	$76.40	$89.58	$82.76	$92.53
Natural gas ($ per mcf)	$1.72	$1.90	$2.36	$2.23
NGL ($ per bbl)	$13.11	$31.76	$21.27	$27.87
Oil equivalent ($ per boe)	$21.67	$26.44	$26.32	$27.92

Interest Expense ($ in millions):

Interest[b]	$40	$56	$173	$169
Derivatives – realized (gains) losses[c]	(2)	(3)	(12)	(9)
Derivatives – unrealized (gains) losses[c]	(31)	10	(72)	67
Total Interest Expense	$7	$63	$89	$227

[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:	**December 31, 2014**	**December 31, 2013**
Beginning cash	$ 90	$ 987
Cash provided by operating activities	829	1,028
Cash flows from investing activities:		
Drilling and completion costs on proved and unproved properties[a]	(1,367)	(1,117)
Acquisition of proved and unproved properties[b]	(280)	(211)
Sales of proved and unproved properties	5,082	668
Geological and geophysical costs	(29)	(17)
Cash paid to purchase leased rigs and compressors	(25)	(262)
Additions to other property and equipment	(26)	(71)

Proceeds from sales of other assets	39	126
Additions to investments	(3)	(36)
Other	1	—
Total cash provided by (used in) investing activities	3,392	(920)
Cash used in financing activities	(203)	(258)
Change in cash and cash equivalents	4,018	(150)
Ending cash	$ 4,108	$ 837

(a) Includes capitalized interest of $9 million and $15 million for the three months ended December 31, 2014 and 2013, respectively.

(b) Includes capitalized interest of $120 million and $163 million for the three months ended December 31, 2014 and 2013, respectively.

TWELVE MONTHS ENDED:	**December 31, 2014**	**December 31, 2013**
Beginning cash	$ 837	$ 287
Cash provided by operating activities	4,634	4,614
Cash flows from investing activities:		
Drilling and completion costs on proved and unproved properties[a]	(4,534)	(5,552)
Acquisition of proved and unproved properties[b]	(1,279)	(974)
Sales of proved and unproved properties	5,781	3,409
Geological and geophysical costs	(47)	(52)
Cash paid to purchase leased rigs and compressors	(499)	(266)
Additions to other property and equipment	(227)	(706)
Proceeds from sales of other assets	1,003	922
Additions to investments	(17)	—
Proceeds from sales of investments	239	71
Decrease in restricted cash	37	—
Other	(3)	181
Total cash provided by (used in) investing activities	454	(2,967)
Cash used in financing activities	(1,817)	(1,097)
Change in cash and cash equivalents	3,271	550
Ending cash	$ 4,108	$ 837

(a) Includes capitalized interest of $39 million and $62 million for the twelve months ended December 31, 2014 and 2013, respectively.

(b) Includes capitalized interest of $553 million and $734 million for the twelve months ended December 31, 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:	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**

Net income available to common stockholders	$ 586	$ 169	$ (159)
Adjustments, net of tax[(a)]:			
Unrealized (gains) losses on derivatives	(663)	(378)	13
Restructuring and other termination costs	(3)	(9)	28
Impairments of fixed assets and other	10	9	126
Net (gains) losses on sales of fixed assets	2	(53)	(7)
Losses on purchases of debt and extinguishment of other financing	2	—	76
Losses on investments	—	—	84
Provision for legal contingencies	94	61	—
Other	6	5	—
Redemption of preferred shares of a subsidiary[(a)]	—	447	—
Adjusted net income available to common stockholders[(b)]	$ 34	$ 251	$ 161
Preferred stock dividends	43	43	43
Earnings allocated to participating securities	10	3	—
Total adjusted net income attributable to Chesapeake	$ 87	$ 297	$ 204
Weighted average fully diluted shares outstanding (in millions)[(c)]	775	776	767
Adjusted earnings per share assuming dilution[(b)]	$ 0.11	$ 0.38	$ 0.27

(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 and adjusted earnings per share assuming dilution are not measures of financial performance under 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 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 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.

(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)

TWELVE MONTHS ENDED:	December 31, 2014	December 31, 2013
Net income available to common stockholders	$ 1,273	$ 474
Adjustments, net of tax[(a)]:		
Unrealized gains on derivatives	(941)	(100)
Restructuring and other termination costs	4	154
Impairments of fixed assets and other	57	341
Net gains on sales of fixed assets	(128)	(187)
Impairments of investments	3	6
Net (gain) loss on sales of investments	(43)	5
Losses on purchases of debt and extinguishment of other financing	126	120
Losses on investments	—	84
Provision for legal contingencies	150	—
Other	9	(1)
Redemption of preferred shares of a subsidiary[(a)]	447	69
Adjusted net income available to common stockholders [(b)]	$ 957	$ 965
Preferred stock dividends	171	171
Earnings allocated to participating securities	26	10
Total adjusted net income attributable to Chesapeake	$ 1,154	$ 1,146
Weighted average fully diluted shares outstanding (in millions)[(c)]	776	765
Adjusted earnings per share assuming dilution[(b)]	$ 1.49	$ 1.50

(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 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.

(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:	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 829	$ 1,184	$ 1,028
Changes in assets and liabilities	44	109	(33)
OPERATING CASH FLOW[(a)]	$ 873	$ 1,293	$ 995

THREE MONTHS ENDED:	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**
NET INCOME	$ 668	$ 692	$ (74)
Interest expense	7	17	63
Income tax expense (benefit)	286	437	(45)
Depreciation and amortization of other assets	38	37	80
Oil, natural gas and NGL depreciation, depletion and amortization	706	688	644
EBITDA[(b)]	$ 1,705	$ 1,871	$ 668

THREE MONTHS ENDED:	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 829	$ 1,184	$ 1,028
Changes in assets and liabilities	44	109	(33)
Interest expense, net of unrealized gains (losses) on derivatives	38	11	53
Oil, natural gas and NGL derivative gains (losses), net	1,049	564	(13)
Cash receipts (payments) on oil, natural gas and NGL derivative settlements, net	(88)	34	30
Stock-based compensation	—	(19)	(20)
Restructuring and other termination costs	(3)	42	(11)
Impairments of fixed assets and other	(14)	(15)	(166)
Net gains (losses) on sales of fixed assets	(2)	86	12
Losses on investments	(7)	(27)	(189)
Provision for legal contingencies	(134)	(100)	—
Losses on purchases of debt and extinguishment of other financing	(2)	—	(3)
Other items	(5)	2	(20)
EBITDA[(b)]	$ 1,705	$ 1,871	$ 668

(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)

TWELVE MONTHS ENDED:	**December 31, 2014**	**December 31, 2013**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 4,634	$ 4,614
Changes in assets and liabilities	392	344
OPERATING CASH FLOW[(a)]	$ 5,026	$ 4,958

TWELVE MONTHS ENDED:	**December 31, 2014**	**December 31, 2013**
NET INCOME	$ 2,056	$ 894
Interest expense	89	227
Income tax expense	1,144	548
Depreciation and amortization of other assets	232	314
Oil, natural gas and NGL depreciation, depletion and amortization	2,683	2,589
EBITDA[(b)]	$ 6,204	$ 4,572

TWELVE MONTHS ENDED:	**December 31, 2014**	**December 31, 2013**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 4,634	$ 4,614
Changes in assets and liabilities	392	344
Interest expense, net of unrealized gains (losses) on derivatives	161	159
Oil, natural gas and NGL derivative gains (losses), net	1,018	129
Cash receipts on oil, natural gas and NGL derivative settlements, net	264	91
Stock-based compensation	(59)	(98)
Restructuring and other termination costs	15	(175)
Impairments of fixed assets and other	(58)	(483)

Net gains on sales of fixed assets	199	302
Provision for legal contingencies	(234)	—
Losses on investments	(80)	(229)
Net gain (loss) on sales of investments	67	(7)
Losses on purchases of debt and extinguishment of other financing	(63)	(40)
Other items	(52)	(35)
EBITDA[b]	$ 6,204	$ 4,572

(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 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 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:	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**
EBITDA	$ 1,705	$ 1,871	$ 668
Adjustments:			
Unrealized (gains) losses on oil, natural gas and NGL derivatives	(916)	(622)	11
Restructuring and other termination costs	(5)	(14)	45
Impairments of fixed assets and other	14	15	203
Net (gains) losses on sales of fixed assets	3	(86)	(12)
Net loss on sales of investments	—	—	136
Losses on purchases of debt and extinguishment of other financing	2	—	123
Provision for legal contingencies	134	100	—

Net income attributable to noncontrolling interests	(29)	(30)	(42)
Other	8	2	—
Adjusted EBITDA[(a)]	$ 916	$ 1,236	$ 1,132

TWELVE MONTHS ENDED:	**December 31, 2014**	**December 31, 2013**
EBITDA	$ 6,204	$ 4,572
Adjustments:		
Unrealized gains on oil, natural gas and NGL derivatives	(1,394)	(228)
Restructuring and other termination costs	7	248
Impairments of fixed assets and other	88	550
Net gains on sales of fixed assets	(199)	(302)
Losses on investments	5	146
Net (gain) loss on sales of investments	(67)	7
Losses on purchases of debt and extinguishment of other financing	197	193
Provision for legal contingencies	234	—
Net income attributable to noncontrolling interests	(139)	(170)
Other	9	—
Adjusted EBITDA[(a)]	$ 4,945	$ 5,016

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

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

(ii) Adjusted ebitda is more comparable to estimates provided by securities analysts.

(iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

Accordingly, adjusted EBITDA should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.

SCHEDULE "A”
CHESAPEAKE ENERGY CORPORATION
MANAGEMENT’S OUTLOOK AS OF FEBRUARY 25, 2015

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

	Year Ending 12/31/2015
Adjusted Production Growth[(a)]	3% - 5%
Absolute Production	
Liquids - mbbls	62 – 64
Oil - mbbls	39 – 40
NGL[(b)] - mbbls	23 – 24

Natural gas - bcf	1,035 – 1,055
Total absolute production - mmboe	235 – 240
Absolute daily rate - mboe	645 – 655
Estimated Realized Hedging Effects[c] (based on 2/23/15 strip prices):	
Oil - $/bbl	$19.94
Natural gas - $/mcf	$0.31
Estimated Basis/Gathering/Marketing/Transportation Differentials to NYMEX Prices:	
Oil - $/bbl	$7.00 – 9.00
NGL - $/bbl	$48.00 – 52.00
Natural gas - $/mcf	$1.70 – 1.90
Fourth quarter MVC estimate ($ in millions)	($180) – (200)
Operating Costs per Boe of Projected Production:	
Production expense	$4.50 – 5.00
Production taxes	$0.45 – 0.55
General and administrative[d]	$1.45 – 1.55
Stock-based compensation (noncash)	$0.20 – 0.25
DD&A of natural gas and liquids assets	$10.50 – 11.50
Depreciation of other assets	$0.60 – 0.70
Interest expense[e]	$1.00 – 1.10
Other ($ millions):	
Marketing, gathering and compression net margin[f]	($40 – 60)
Net income attributable to noncontrolling interests and other[g]	($30 – 50)
Book Tax Rate	37%
Capital Expenditures ($ in millions)[h]	$3,500 – 4,000
Capitalized Interest ($ in millions)	$500
Total Capital Expenditures ($ in millions)	$4,000 – 4,500

(a) Based on 2014 production of 622 mboe/day adjusted for 2014 sales and the potential sale of Cleveland Tonkawa assets in 2015.

(b) Assumes ethane recovery in the Utica to fulfill Chesapeake's pipeline commitments, no ethane recovery in the Powder River Basin and partial ethane recovery in the Mid-Continent and Eagle Ford.

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

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

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

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

(g) Net income attributable to noncontrolling interests of Chesapeake Granite Wash Trust and CHK Cleveland Tonkawa L.L.C.

(h) Includes capital expenditures for drilling and completion, acquisition of unproved properties, geological and geophysical costs and other property and plant and equipment

Oil, Natural Gas and NGL Hedging Activities

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

As of January 31, 2015, the company had downside protection on approximately 43% of its projected 2015 oil production at an average price of $93.39 per bbl of which 11% is hedged under collar arrangements with upside to an average NYMEX price of $90/bbl and exposure below an average NYMEX price of $80/bbl. Approximately 43% of the company's projected 2015 natural gas production had downside protection at an average price of $4.21 per thousand cubic feet of natural gas, of which 20% is hedged under collar arrangements with upside to an average NYMEX price of $4.29/mcf and exposure below an average NYMEX price of $3.37/mcf.

The company’s crude oil hedging positions as of January 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)
Q1 2015	3,834	$ 94.07	$ 50
Q2 2015	3,041	94.49	61
Q3 2015	2,868	94.82	62
Q4 2015	2,714	95.15	63
Total 2015	12,457	$ 94.58	$ 236
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
Q1 2015	1,080	$ 80.00	$ 90.00	$ 98.94
Q2 2015	1,092	80.00	90.00	98.94
Q3 2015	1,104	80.00	90.00	98.94
Q4 2015	1,104	80.00	90.00	98.94
Total 2015	4,380	$ 80.00	$ 90.00	$ 98.94

Crude Oil Net Written Call Options

	Call Options (mbbls)	Avg. NYMEX Strike Price
Q1 2015	1,485	$ 100.00
Q2 2015	3,349	91.89
Q3 2015	3,386	91.89
Q4 2015	3,386	91.89
Total 2015	11,606	$ 92.93
Total 2016 – 2017	24,220	$ 100.07

The company’s natural gas hedging positions as of January 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 Gains (Losses) from Closed Trades and Premiums for Call Options ($ in millions)
Q1 2015	81	$ 4.53	$ (39)
Q2 2015	53	3.95	(30)
Q3 2015	52	3.94	(31)
Q4 2015	52	3.94	(31)
Total 2015	238	$ 4.14	$ (131)
Total 2016 – 2022	37	$ 3.95	$ (187)

Natural Gas Three-Way Collars

	Open Collars (bcf)	Avg. NYMEX Sold Put Price	Avg. NYMEX Bought Put Price	Avg. NYMEX Sold Call Price
Q1 2015	100	$ 3.36	$ 4.42	$ 4.65
Q2 2015	35	3.38	4.17	4.37
Q3 2015	36	3.38	4.17	4.37
Q4 2015	36	3.38	4.17	4.37
Total 2015	207	$ 3.37	$ 4.29	$ 4.51

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)
Q1 2015	28	$ 1.28
Q2 2015	8	(0.34)
Q3 2015	8	(0.33)
Q4 2015	8	(0.33)
Total 2015	52	$ 0.55
Total 2016 - 2022	8	$ (1.02)

Source: Chesapeake Energy Corporation

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http://investors.chk.com/2015-02-25-chesapeake-energy-corporation-reports-financial-and-operational-results-for-the-2014-full-year-and-fourth-quarter