NEWS RELEASE

Chesapeake Energy Corporation Reports Financial Results for the 2010 Second Quarter

Company Reports 2010 Second Quarter Net Income to Common Stockholders of $235 Million, or $0.37 per Fully Diluted Common Share, on Revenue of $2.0 Billion; Company Reports Adjusted Net Income Available to Common Stockholders of $491 Million, or $0.75 per Fully Diluted Common Share, Adjusted Ebitda of $1.3 Billion and Operating Cash Flow of $1.1 Billion Company Reports 2010 Second Quarter Production of 2.789 Bcfe per Day, an Increase of 14% over 2009 Second Quarter Production and 8% over 2010 First Quarter Production; 2010 Second Quarter Production of Liquids Increases 41% Year-Over-Year to 10% of Total Production and 17% of Total Realized Production Revenue Company Provides Update on its Strategic and Financial Plan to Reduce Capital Expenditures on Natural Gas Plays, Increase Capital Expenditures on Liquids-Rich Plays, Monetize Assets and Reduce Debt

OKLAHOMA CITY, OKLAHOMA, AUGUST 3, 2010 – Chesapeake Energy Corporation (NYSE:CHK) today announced financial results for the 2010 second quarter. For the 2010 second quarter, Chesapeake reported net income to common stockholders of $235 million ($0.37 per fully diluted common share), operating cash flow of $1.127 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $791 million (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization) on revenue of $2.012 billion and production of 254 billion cubic feet of natural gas equivalent (bcfe).

The company's 2010 second quarter results include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Excluding the items detailed below, for the 2010 second quarter, Chesapeake reported adjusted net income to common stockholders of $491 million ($0.75 per fully diluted common share) and adjusted ebitda of $1.256 billion. The excluded items and their effects on 2010 second quarter reported results are detailed as follows:

- a non-cash unrealized after-tax mark-to-market loss of $214 million resulting from the company's natural gas, oil and interest rate hedging programs; and
- an after-tax charge of $42 million related to the redemption of certain of the company's senior notes.

The various items described above do not materially affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 12 – 16 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2010 second quarter and compares them to results during the 2010 first quarter and the 2009 second quarter.

	Three Months Ended		
	6/30/10	**3/31/10**	**6/30/09**
Average daily production (in mmcfe) [a]	2,789	2,586	2,453
Natural gas as % of total production	90	90	92
Natural gas production (in bcf)	227.2	209.6	204.3
Average realized natural gas price ($/mcf) [b]	5.66	6.31	5.56
Oil and NGL production (in mbbls)	4,429	3,871	3,152
Average realized oil and NGL price ($/bbl) [b]	61.43	67.70	56.72
Natural gas equivalent production (in bcfe)	253.8	232.8	223.2
Natural gas equivalent realized price ($/mcfe) [b]	6.14	6.80	5.89
Marketing, gathering and compression net margin($/mcfe)	.12	.12	.14
Service operations income ($/mcfe)	.02	.03	(.01)
Production expenses ($/mcfe)	(.84)	(.89)	(.95)
Production taxes ($/mcfe)	(.15)	(.21)	(.11)
General and administrative costs ($/mcfe) [c]	(.34)	(.38)	(.25)
Stock-based compensation ($/mcfe)	(.08)	(.09)	(.09)
DD&A of natural gas and oil properties ($/mcfe)	(1.34)	(1.32)	(1.32)
D&A of other assets ($/mcfe)	(.21)	(.21)	(.26)
Interest expense ($/mcfe) [b]	(.13)	(.22)	(.29)
Operating cash flow ($ in millions) [d]	1,127	1,166	1,006
Operating cash flow ($/mcfe)	4.44	5.01	4.51
Adjusted ebitda ($ in millions) [e]	1,256	1,270	1,030
Adjusted ebitda ($/mcfe)	4.95	5.46	4.62
Net income to common stockholders ($ in millions)	235	733	237
Earnings per share – assuming dilution ($)	.37	1.14	.39
Adjusted net income to common stockholders ($ in millions) [f]	491	524	377
Adjusted earnings per share – assuming dilution ($)	.75	.82	.62

(a) 2010 production reflects the sale of a 25% joint venture interest in the company's Barnett Shale assets on January 25, 2010 (averaging approximately 124 mmcfe per day and 174 mmcfe per day during the 2010 first and second quarters, respectively), the company's sixth volumetric production payment transaction on February 5, 2010 (averaging approximately 14 mmcfe per day and 22 mmcfe per day during the 2010 first and second quarters, respectively), the company's seventh volumetric production payment transaction on June 14, 2010 (averaging approximately 5 mmcfe per day during the 2010 second quarter) and the sale of producing properties in Virginia and in the Permian Basin in the 2010 second quarter (averaging approximately 20 mmcfe per day during the 2010 second quarter)

(b)Includes the effects of realized gains (losses) from hedging, but does not include the effects of unrealized gains (losses) from hedging

(c)Excludes expenses associated with non-cash stock-based compensation

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

(e)Defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 14

(f)Defined as net income (loss) available to common stockholders, as adjusted to remove the effects of certain items detailed on page 15

2010 Second Quarter Average Daily Production of 2.789 Bcfe per Day Increases 14% over 2009 Second Quarter Production and 8% over 2010 First Quarter Production; 2010 Second Quarter Production of Liquids Increases 41% Year-Over-Year to 10% of Total Production

As announced on August 2, 2010, Chesapeake's daily production for the 2010 second quarter averaged 2.789 bcfe, an increase of 203 million cubic feet of natural gas equivalent (mmcfe), or 8%, above the 2.586 bcfe produced per day in the 2010 first quarter and an increase of 336 mmcfe, or 14%, over the 2.453 bcfe produced per day in the 2009 second quarter.

Chesapeake's average daily production of 2.789 bcfe for the 2010 second quarter consisted of 2.497 billion cubic feet of natural gas (bcf) and 48,670 barrels of oil and natural gas liquids (NGLs) (bbls). The company's 2010 second quarter production of 253.8 bcfe was comprised of 227.2 bcf (90% on a natural gas equivalent basis) and 4.4 million barrels of oil and NGLs (mmbbls) (10% on a natural gas equivalent basis). The company's year-over-year growth rate of natural gas production was 11% and its year-over-year growth rate of oil and NGL (liquids) production was 41%. The company's percentage of revenue from liquids in the 2010 second quarter was 17% of realized production revenue compared to 14% in the 2009 second quarter.

Chesapeake is projecting full-year production growth of approximately 13% in 2010 and 18% in 2011, including production growth from liquids of approximately 60% in 2010 and 80% in 2011. Of Chesapeake's projected 13% and 18% growth rates in 2010 and 2011, approximately 37% and 50%, respectively, of the growth is projected to come from increased liquids production.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2010 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $5.66 per thousand cubic feet (mcf) and $61.43 per bbl, for a realized natural gas equivalent price of $6.14 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas and oil hedging activities during the 2010 second quarter generated a $2.43 gain per mcf and a $4.85 gain per bbl, for a 2010 second quarter realized hedging gain of $573 million, or $2.26 per mcfe.

By comparison, average prices realized during the 2009 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $5.56 per mcf and $56.72 per bbl, for a realized natural gas equivalent price of $5.89 per mcfe. Realized gains from natural gas and oil hedging activities during the 2009 second quarter generated a $2.88 gain per mcf and a $3.13 gain per bbl, for a 2009 second quarter realized hedging gain of $597 million, or $2.68 per mcfe.

The following tables summarize Chesapeake's 2010 and 2011 open hedge positions through swaps and collars as of August 3, 2010. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, Chesapeake may either increase or decrease its hedging positions at any time in the future without notice.

Open Swap Positions as of August 3, 2010

	Natural Gas		Oil	
Year	**% Hedged**	**$ NYMEX**	**% Hedged**	**$ NYMEX**
2010	51%	7.58	43%	89.62

2011	30%	7.39	10%	96.09

Open Natural Gas Collar Positions as of August 3, 2010

Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2010	2%	7.60	11.75
2011	1%	7.70	11.50

As of July 30, 2010, Chesapeake's natural gas and oil hedging positions with its 14 different counterparties had a positive mark-to-market value of approximately $110 million. The company's natural gas and oil realized hedging gains for the first six months of 2010 were $972 million and since January 1, 2001 have been $5.4 billion.

The company's updated forecasts and hedging positions for 2010 and 2011 are attached to this release in an Outlook dated August 3, 2010, labeled as Schedule "A," which begins on page 17. This Outlook has been changed from the Outlook dated May 4, 2010, attached as Schedule "B," which begins on page 21, to reflect various updated information.

Company Provides Update on its Strategic and Financial Plan to Reduce Capital Expenditures on Natural Gas Plays, Increase Capital Expenditures on Liquids-Rich Plays, Monetize Assets and Reduce Debt

Chesapeake has accomplished multiple parts of its strategic and financial plan outlined on May 10, 2010. During the 2010 second quarter, the company issued $2.6 billion of convertible preferred stock, called for redemption $1.9 billion of senior notes and sold approximately $750 million of leasehold and producing properties. The asset sales included the company's seventh volumetric production payment (VPP) for proceeds of approximately $335 million, or $8.73 per mcfe of proved reserves, and producing properties and gathering assets in Virginia and in the Permian Basin for proceeds of approximately $330 million, or $1.70 per mcfe.

During the 2010 first half, the company reduced its net debt to total book capitalization ratio and its net debt per proved reserve ratio from 49% and $0.84 per mcfe, respectively, at December 31, 2009 to 40% and $0.64 per mcfe, respectively, at June 30, 2010 – reductions of 18% and 24% in just six months. The company remains committed to achieving investment grade credit metrics by no later than year-end 2012.

In recognition of the significant and persistent value gap that has developed between natural gas and oil prices, Chesapeake has accelerated its transition to a more liquids-rich asset base. The company has redirected a significant portion of its technological, geoscientific, leasehold acquisition and drilling expertise to identifying, securing and commercializing unconventional liquids-rich plays. Chesapeake's goal is to reach a balanced mix of natural gas and liquids revenue as quickly as possible through organic drilling, rather than through acquisitions, at very low per net acre leasehold acquisition costs and low drilling and completion costs. Having successfully established itself during the past five years as the industry leader in finding, developing, monetizing and producing unconventional natural gas plays, Chesapeake is now focused on achieving the same leadership position in unconventional liquids-rich plays. The company believes that doing so during a period of much higher value for oil and NGLs compared to natural gas will significantly enhance the company's already strong profitability and returns on invested capital.

Chesapeake's strategy to accomplish this goal is set forth below:

- Reduce drilling of natural gas wells except for those required to hold by production (HBP) leasehold or to use a drilling carry provided by a joint venture partner until such time as natural gas prices rise above $6.00 per mcf;
- Lease and develop substantial new liquids-rich plays in which the company can acquire very large leasehold positions of 250,000-750,000 net acres;
- Within one year of acquisition, sell a minority interest in a new play, recovering all or virtually all of the cost to acquire the leasehold in the play, and to fund a significant portion of Chesapeake's future drilling costs in the play;
- Accelerate drilling of liquids-rich plays until year-end 2012 when the company's drilling capital expenditures are balanced approximately 50/50 between natural gas plays and liquids-rich plays;
- Continue adding proved reserves, net of monetizations and divestitures, of approximately 2.5 - 3.0 tcfe (415 - 500 mmboe) annually; and
- Accomplish these goals without the issuance of additional equity and with a reduction of debt levels such that the company becomes investment grade within the next few years.

Accordingly, compared to 2010, Chesapeake is reducing its projected 2011 drilling and completion capital expenditures on natural gas plays by approximately $400 million and increasing its drilling and completion capital expenditures on liquids-rich plays by approximately $400 million. On a net basis after joint venture carries, Chesapeake is projecting 2011 drilling and completion capital expenditures will remain flat compared to 2010 drilling and completion capital expenditures of approximately $4.5 - $4.6 billion. The following table provides an analysis and projection of how Chesapeake's operated net drilling and completion capital expenditures on liquids plays are expected to increase from 13% in 2008 to approximately 55% in 2012.

	CHK Operated Drilling and Completion Capital Expenditures:	
Year	**Natural Gas Plays**	**Liquids Plays**
2008 (actual)	87%	13%
2009 (actual)	90%	10%
2010 (1H actual, 2Hprojected)	68%	32%
2011 (projected)	59%	41%
2012 (projected)	45%	55%

This planned transition will result in a more balanced portfolio between natural gas and liquids and by year-end 2015, Chesapeake expects to increase its liquids production to approximately 200,000 bbls per day, or approximately 25% of total production (using a 6:1 natural gas to liquids ratio), through organic growth and expects revenue from liquids to be approximately 40% of total production revenue.

During the 2010 first half, Chesapeake invested heavily in new leasehold acquisitions in various liquids-rich plays, including: the Anadarko Basin's Granite Wash, Cleveland, Tonkawa and Mississippian plays; the Permian Basin's Wolfcamp, Bone Spring, Avalon and Wolfberry plays; the Eagle Ford Shale in South Texas; the Niobrara Shale in the Powder River and DJ Basins; the Frontier Sand in the Powder River Basin; and various other new plays the company is not yet ready to discuss.

During the 2010 second half and throughout 2011, the company will focus on recapturing a significant portion of these new leasehold expenditures through joint ventures in several of its new liquids-rich plays. The first of these is expected to be a joint venture in the Eagle Ford Shale that the company expects to announce in the 2010 third quarter. Further joint ventures are planned for later in 2010 or in early 2011. Other anticipated significant asset monetizations during the second half of 2010 and the first half of 2011 include a volumetric production payment, a Marcellus Shale subsidiary equity investment, a midstream asset sale and various other smaller planned monetizations. In total, Chesapeake is targeting proceeds of approximately $3.0 - 3.5 billion in the 2010 second half and approximately $2.5 - 3.0 billion in 2011 from asset monetizations, which will enable the company to further reduce its debt and accelerate drilling on its unconventional liquids-rich plays.

Conference Call Information

A conference call to discuss this release of financial results and the company's release of its operational results issued on August 2, 2010 has been scheduled for Wednesday, August 4, 2010, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-312-4373** or toll-free **866-454-4205**. The passcode for the call is **9144645**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from 1:00 p.m. EDT on August 4, 2010 through midnight EDT on August 18, 2010. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **9144645**. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of the website. The webcast of the conference call will be available on Chesapeake's website for one year.

This press release and the accompanying Outlooks 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 give our current expectations or forecasts of future events. They include expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned drilling activity, drilling and completion costs and anticipated asset sales, projected cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our 2009 Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2010. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; potential differences in our interpretations of new reserve disclosure rules and future SEC guidance; inability 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 and oil sales and the need to secure hedging liabilities; a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business; general economic conditions negatively impacting us and our business counterparties; transportation capacity constraints and interruptions that could adversely affect our cash flow; and adverse results in pending or future litigation.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.

Chesapeake Energy Corporation is one of the largest producers of natural gas and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Fayetteville, Haynesville, Marcellus and Bossier natural gas shale plays and in the Eagle Ford, Granite Wash and various other unconventional oil plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Further information is available at www.chk.com.

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

THREE MONTHS ENDED:	June 30, 2010		June 30, 2009	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas and oil sales	1,161	4.57	1,097	4.92
Marketing, gathering and compression sales	793	3.13	532	2.38
Service operations revenue	58	0.23	44	0.20
Total Revenues	2,012	7.93	1,673	7.50
OPERATING COSTS:				
Production expenses	213	0.84	213	0.95
Production taxes	37	0.15	24	0.11
General and administrative expenses	106	0.41	74	0.33
Marketing, gathering and compression expenses	763	3.01	500	2.24
Service operations expense	53	0.21	46	0.21
Natural gas and oil depreciation, depletion and amortization	340	1.34	295	1.32
Depreciation and amortization of other assets	53	0.21	58	0.26
Impairment of other assets	—	—	5	0.02
Restructuring costs	—	—	34	0.16
Total Operating Costs	1,565	6.17	1,249	5.60
INCOME FROM OPERATIONS	447	1.76	424	1.90
OTHER INCOME (EXPENSE):				
Other income (expense)	20	0.08	(2)	(0.01)
Interest income (expense)	16	0.06	(22)	(0.10)
Impairment of investments	—	—	(10)	(0.04)
Loss on redemptions or exchanges of Chesapeake debt	(69)	(0.27)	(2)	(0.01)

Total Other Income (Expense)	(33)	(0.13)	(36)	(0.16)
INCOME BEFORE INCOME TAXES	414	1.63	388	1.74
Income Tax Expense:				
Current income taxes	5	0.02	1	—
Deferred income taxes	154	0.61	144	0.65
Total Income Tax Expense	159	0.63	145	0.65
NET INCOME	255	1.00	243	1.09
Preferred stock dividends	(20)	(0.07)	(6)	(0.03)
NET INCOME AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	235	0.93	237	1.06
EARNINGS PER COMMON SHARE:				
Basic	$ 0.37		$ 0.39	
Diluted	$ 0.37		$ 0.39	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	631		603	
Diluted	635		610	

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

SIX MONTHS ENDED:	**June 30, 2010**		**June 30, 2009**	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	3,059	6.29	2,494	5.72
Marketing, gathering and compression sales	1,637	3.36	1,084	2.49
Service operations revenue	114	0.24	90	0.20
Total Revenues	4,810	9.89	3,668	8.41
OPERATING COSTS:				
Production expenses	421	0.86	451	1.03
Production taxes	85	0.18	46	0.11
General and administrative expenses	215	0.44	164	0.38
Marketing, gathering and compression expenses	1,578	3.24	1,023	2.35
Service operations expense	102	0.21	87	0.20
Natural gas and oil depreciation, depletion and amortization	647	1.33	742	1.70
Depreciation and amortization of other assets	103	0.21	115	0.26
Impairment of natural gas and oil properties and other assets	—	—	9,635	22.08
Restructuring costs	—	—	34	0.08
Total Operating Costs	3,151	6.47	12,297	28.19
INCOME (LOSS) FROM OPERATIONS	1,659	3.42	(8,629)	(19.78)
OTHER INCOME (EXPENSE):				
Other income (expense)	35	0.07	5	0.01
Interest expense	(9)	(0.02)	(8)	(0.02)
Impairment of investments	—	—	(162)	(0.37)

Loss on redemptions or exchanges of Chesapeake debt	(71)	(0.15)	(2)	—
Total Other Income (Expense)	(45)	(0.10)	(167)	(0.38)
INCOME (LOSS) BEFORE INCOME TAXES	1,614	3.32	(8,796)	(20.16)
Income Tax Expense (Benefit):				
Current income taxes	5	0.01	1	—
Deferred income taxes	616	1.27	(3,299)	(7.56)
Total Income Tax Expense (Benefit)	621	1.28	(3,298)	(7.56)
NET INCOME (LOSS)	993	2.04	(5,498)	(12.60)
Preferred stock dividends	(25)	(0.05)	(12)	(0.03)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	968	1.99	(5,510)	(12.63)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 1.54		$ (9.18)	
Diluted	$ 1.49		$ (9.18)	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	630		600	
Diluted	665		600	

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

	June 30, 2010	December 31, 2009
Cash and cash equivalents	$ 601	$ 307
Other current assets	2,417	2,139
Total Current Assets	3,018	2,446
Property and equipment (net)	27,830	26,710
Other assets	1,321	758
Total Assets	$ 32,169	$ 29,914
Current liabilities	$ 3,655	$ 2,688
Long-term debt, net [(a)]	10,501	12,295
Asset retirement obligations	285	282
Other long-term liabilities	1,367	1,249
Deferred tax liability	1,546	1,059
Total Liabilities	17,354	17,573
Chesapeake stockholders’ equity	14,815	11,444
Noncontrolling interest[(b)]	—	897
Total Equity	14,815	12,341
Total Liabilities & Equity	$ 32,169	$ 29,914
Common Shares Outstanding (in millions)	651	648

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION

($ in millions)
(unaudited)

	June 30, 2010	% of Total Book Capitalization	December 31, 2009	% of Total Book Capitalization
Total debt, net of cash [(a)]	$ 9,900	40%	$ 11,988	49%
Chesapeake stockholders' equity	14,815	60%	11,444	47%
Noncontrolling interest [(b)]	—	—	897	4%
Total	$24,715	100%	$ 24,329	100%

(a)At June 30, 2010, includes $1.521 billion of combined borrowings under the company's $3.5 billion revolving bank credit facility and the company's $250 million midstream revolving bank credit facility. At June 30, 2010, the company had $2.215 billion of additional borrowing capacity under these two revolving bank credit facilities.

(b)Effective January 1, 2010, we no longer consolidate the company's midstream joint venture and consequently no longer report a noncontrolling interest related to this investment.

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

	THREE MONTHS ENDED JUNE 30, 2010	THREE MONTHS ENDED JUNE 30, 2009	SIX MONTHS ENDED JUNE 30, 2010	SIX MONTHS ENDED JUNE 30, 2009
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 733	$ 548	$ 1,676	$ 1,223
Natural gas derivatives – realized gains	552	587	931	1,096
Natural gas derivatives – unrealized gains (losses)	(195)	(192)	219	(123)
Total Natural Gas Sales	1,090	943	2,826	2,196
Oil sales	251	169	493	272
Oil derivatives – realized gains (losses)	21	10	41	19
Oil derivatives – unrealized gains (losses)	(201)	(25)	(301)	7
Total Oil Sales	71	154	233	298
Total Natural Gas and Oil Sales	$ 1,161	$ 1,097	$ 3,059	$ 2,494
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 3.23	$ 2.68	$ 3.84	$ 3.06
Oil ($ per bbl)	$ 56.58	$ 53.59	$ 59.38	$ 45.19
Natural gas equivalent ($ per mcfe)	$ 3.88	$ 3.21	$ 4.46	$ 3.43
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 5.66	$ 5.56	$ 5.97	$ 5.80
Oil ($ per bbl)	$ 61.43	$ 56.72	$ 64.35	$ 48.32
Natural gas equivalent ($ per mcfe)	$ 6.14	$ 5.89	$ 6.46	$ 5.98

Interest Expense (Income) ($ in millions):				
Interest	$ 35	$ 69	$ 90	$ 107
Derivatives – realized gains	(2)	(5)	(4)	(12)
Derivatives – unrealized gains	(49)	(42)	(77)	(87)
Total Interest Expense (Income)	$ (16)	$ 22	$ 9	$ 8

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

THREE MONTHS ENDED:	**June 30, 2010**	**June 30, 2009**
Beginning cash	$ 516	$ 83
Cash provided by operating activities	$ 1,795	$ 737
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$ (1,311)	$ (753)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(1,825)	(305)
Divestitures of proved and unproved properties, leasehold and VPPs	688	228
Investments, net	(103)	10
Other property and equipment, net	(150)	(277)
Other	(17)	(1)
Total cash (used in) investing activities	$ (2,718)	$ (1,098)
Cash provided by financing activities	$ 1,008	$ 832
Ending cash	$ 601	$ 554

SIX MONTHS ENDED:	**June 30, 2010**	**June 30, 2009**
Beginning cash	$ 307	$ 1,749
Cash provided by operating activities	$ 2,978	$ 1,998
Cash (used in) provided by investing activities:		
Exploration and development of natural gas and oil properties	$(2,331)	$(2,108)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(2,855)	(710)
Divestitures of proved and unproved properties, leasehold and VPPs	1,933	228
Investments, net	(109)	2
Other property and equipment, net	(373)	(876)
Other	3	(1)
Total cash (used in) investing activities	$(3,732)	$(3,465)
Cash provided by financing activities	$ 1,048	$ 272
Ending cash	$ 601	$ 554

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	**June 30, 2010**	**March 31, 2010**	**June 30, 2009**

CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,795	$ 1,183	$ 737
Changes in assets and liabilities	(668)	(17)	269
OPERATING CASH FLOW [(a)]	$ 1,127	$ 1,166	$ 1,006

THREE MONTHS ENDED:	**June 30, 2010**	**March 31, 2010**	**June 30, 2009**
NET INCOME (LOSS)	$ 255	$ 738	$ 243
Income tax expense (benefit)	159	462	145
Interest expense (income)	(16)	25	22
Depreciation and amortization of other assets	53	50	58
Natural gas and oil depreciation, depletion and amortization	340	308	295
EBITDA [(b)]	$ 791	$ 1,583	$ 763

THREE MONTHS ENDED:	**June 30, 2010**	**March 31, 2010**	**June 30, 2009**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,795	$ 1,183	$ 737
Changes in assets and liabilities	(668)	(17)	269
Interest expense (income)	(16)	25	22
Unrealized gains (losses) on natural gas and oil derivatives	(396)	315	(216)
Other items	76	77	(49)
EBITDA [(b)]	$ 791	$ 1,583	$ 763

(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 accounting principles generally accepted in the United States (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 (loss) before income tax expense, interest expense 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 and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
($ in millions)
(unaudited)

SIX MONTHS ENDED:	June 30, 2010	June 30, 2009
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,978	$ 1,998
Changes in assets and liabilities	(684)	7
OPERATING CASH FLOW [(a)]	$ 2,294	$ 2,005

SIX MONTHS ENDED:	June 30, 2010	June 30, 2009
NET INCOME (LOSS)	$ 993	$ (5,498)
Income tax expense (benefit)	621	(3,298)
Interest expense (income)	9	8
Depreciation and amortization of other assets	103	115
Natural gas and oil depreciation, depletion and amortization	647	742
EBITDA [(b)]	$ 2,373	$ (7,931)

SIX MONTHS ENDED:	June 30, 2010	June 30, 2009
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,978	$ 1,998
Changes in assets and liabilities	(684)	7
Interest expense (income)	9	8
Unrealized gains (losses) on natural gas and oil derivatives	(82)	(116)
Impairment of natural gas and oil properties and other assets	—	(9,635)
Other items	152	(193)
EBITDA [(b)]	$ 2,373	$ (7,931)

(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 accounting principles generally accepted in the United States (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 (loss) before income tax expense, interest expense 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 and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

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

THREE MONTHS ENDED:	**June 30, 2010**	**March 31, 2010**	**June 30, 2009**
EBITDA	$ 791	$ 1,583	$ 763
Adjustments:			
Unrealized (gains) losses on natural gas and oil derivatives	396	(315)	216
Loss on redemptions or exchanges of Chesapeake debt	69	2	2
Impairment of other assets	—	—	5
Impairment of investments	—	—	10
Restructuring costs	—	—	34
Adjusted EBITDA [(a)]	$ 1,256	$ 1,270	$ 1,030

(a) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as 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.

SIX MONTHS ENDED:	**June 30, 2010**	**June 30, 2009**
EBITDA	$ 2,373	$ (7,931)
Adjustments:		
Unrealized (gains) losses on natural gas and oil derivatives	82	116
Loss on redemptions or exchanges of Chesapeake debt	71	2
Impairment of natural gas and oil properties and other assets	—	9,635
Impairment of investments	—	162
Restructuring costs	—	34
Adjusted EBITDA [(a)]	$ 2,526	$ 2,018

(a) Adjusted ebitda excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as 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.

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

THREE MONTHS ENDED:	**June 30, 2010**	**March 31, 2010**	**June 30, 2009**
Net income available to Chesapeake common stockholders	$ 235	733	$ 237
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	214	(210)	109
Loss on redemptions or exchanges of Chesapeake debt, net of tax	42	1	1
Impairment of other assets, net of tax	—	—	3
Impairment of investments, net of tax	—	—	6
Restructuring costs, net of tax	—	—	21
Adjusted net income available to Chesapeake common stockholders[(a)]	491	524	377
Preferred stock dividends	20	6	6
Total adjusted net income	$ 511	$ 530	$ 383
Weighted average fully diluted shares outstanding [(b)]	682	647	622
Adjusted earnings per share assuming dilution[(a)]	$ 0.75	$ 0.82	$ 0.62

(a) 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 discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings 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.

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

CHESAPEAKE ENERGY CORPORATION

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

SIX MONTHS ENDED:	**June 30, 2010**	**June 30, 2009**
Net income (loss) available to Chesapeake common stockholders	$ 968	$(5,510)
Adjustments:		

Unrealized (gains) losses on derivatives, net of tax	3	19
Loss on redemptions or exchanges of Chesapeake debt, net of tax	44	1
Impairment of natural gas and oil properties and other assets, net of tax	—	6,022
Impairment of investments, net of tax	—	102
Restructuring costs, net of tax	—	21
Adjusted net income available to Chesapeake common stockholders [(a)]	1,015	655
Preferred stock dividends	25	12
Total adjusted net income	$ 1,040	$667
Weighted average fully diluted shares outstanding [(b)]	665	618
Adjusted earnings per share assuming dilution[(a)]	$ 1.56	$1.08

(a) 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 discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings 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.

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

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF AUGUST 3, 2010

Years Ending December 31, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of August 3, 2010, we are using the following key assumptions in our projections for 2010 and 2011.

The primary changes from our May 4, 2010 Outlook are in ***italicized bold*** and are explained as follows:

1)Our production guidance has been increased;

2)Projected effects of changes in our hedging positions have been updated;

3)Equivalent shares outstanding and interest expense has been updated to reflect our private placement of $2.6 billion of preferred stock and the calling and subsequent repayment of certain senior notes; and

4)Our cash flow projections and drilling and completion capital expenditures have been updated.

	Year Ending 12/31/2010	**Year Ending 12/31/2011**
Estimated Production:		
Natural gas – bcf	***898 – 918***	990 – 1,010
Oil – mbbls	***19,000***	***34,000***
Natural gas equivalent – bcfe	***1,012 – 1,032***	***1,194 – 1,214***

	Year Ending 12/31/2010	Year Ending 12/31/2011
Daily natural gas equivalent midpoint – mmcfe	***2,800***	***3,300***
Year-over-year (YOY) estimated production increase	***12 – 14%***	***17 – 19%***
YOY estimated production increase excluding asset sales	***20 – 22%***	***19 – 21%***
NYMEX Price[(a)] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$4.97***	***$5.50***
Oil - $/bbl	***$79.19***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	***$1.88***	***$0.62***
Oil - $/bbl	***$3.98***	***$2.81***
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	15 – 20%	15 – 20%
Oil - $/bbl	***20 – 25%***	***20 – 25%***
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.85 – 0.95	$0.85 – 0.95
Production taxes (~5% of O&G revenues)	$0.25 – 0.30	***$0.25 – 0.30***
General and administrative[(b)]	$0.30 – 0.35	$0.30 – 0.35
Stock-based compensation (non-cash)	$0.09 – 0.11	$0.09 – 0.11
DD&A of natural gas and oil assets	$1.35 – 1.55	$1.35 – 1.55
Depreciation of other assets	$0.20 – 0.25	$0.20 – 0.25
Interest expense[(c)]	***$0.15 – 0.20***	***$0.20 – 0.25***
Other Income per Mcfe:		
Marketing, gathering and compression net margin	***$0.09 – 0.11***	***$0.09 – 0.11***
Service operations net margin	***$0.02 – 0.04***	***$0.02 – 0.04***
Other income (including equity investments)	***$0.06 – 0.08***	***$0.06 – 0.08***
Book Tax Rate (all deferred)	38.5%	38.5%
Equivalent Shares Outstanding (in millions):		
Basic	630 – 635	640 – 645
Diluted	***705 – 710***	***750 – 755***
Operating cash flow before changes in assets and liabilities[(d)(e)]	***$4,900 – 5,000***	***$5,000 – 5,600***
Drilling and completion costs, net of joint venture carries	***($4,500 – 4,600)***	***($4,500 – 4,600)***

Note: refer to footnotes on following page

(a)NYMEX natural gas prices have been updated for actual contract prices through August 2010 and NYMEX oil prices have been updated for actual contract prices through June 2010.

(b)Excludes expenses associated with noncash stock compensation.

(c)Does not include gains or losses on interest rate derivatives.

(d)A non-GAAP financial measure. We are unable to provide a 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.

(e)Assumes NYMEX prices of $5.00 to $6.00 per mcf and $80.00 per bbl in 2010 and in 2011.

At June 30, 2010, the company had approximately $2.8 billion of cash and cash equivalents and additional borrowing capacity under its two revolving bank credit facilities.

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future natural gas and oil production. These strategies include:

1)Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

2)Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party.

3)Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

4)Call options: Chesapeake sells call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

5)Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these nonqualifying derivatives that occur prior to their maturity (i.e., because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in natural gas and oil sales.

The company currently has the following open natural gas swaps in place for 2010 and 2011 and also has the following gains from lifted natural gas trades:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains from Lifted Trades ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q3 2010	119	$ 7.46			$ 59.1	
Q4 2010	120	$ 7.70			$ ***62.1***	
Q3-Q4 2010[a]	***239***	***$ 7.58***	***472***	***51%***	$***121.2***	***$ 0.26***
Total 2011[a]	***303***	***$ 7.39***	1,000	***30%***	$ 59.6	$ 0.06

(a)Certain hedging arrangements include knockout swaps with provisions limiting the counterparty’s exposure at prices ranging from $6.50 to $6.75 covering 5 bcf in Q3-Q4 2010 and $5.75 to $6.50 covering 24 bcf in 2011.

The company currently has the following open natural gas collars in place for 2010 and 2011:

	Open Collars (Bcf)	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production (Bcf)	Open Collars as a % of Estimated Total Natural Gas Production
Q3 2010	4	$ 7.60	$ 11.75		
Q4 2010	4	$ 7.60	$ 11.75		
Q3-Q4 2010	***8***	***$ 7.60***	***$ 11.75***	***472***	***2%***
Total 2011	7	$ 7.70	$ 11.50	1,000	1%

The company currently has the following natural gas written call options in place for 2010 and 2011:

	Call Options (Bcf)	Avg. NYMEX Strike Price	Avg. Premium per mcf	Assuming Natural Gas Production (Bcf)	Call Options as a % of Estimated Total Natural Gas Production
Q3 2010	***34***	***$ 10.01***	***$ 1.25***		
Q4 2010	39	$ 10.07	$ 1.10		
Q3-Q4 2010	**73**	***$ 10.04***	***$ 1.17***	***472***	***15%***
Total 2011	69	$ 9.51	$ 0.61	1,000	7%

The company has the following natural gas basis protection swaps in place for 2010, 2011 and 2012:

	Non-Appalachia		Appalachia	
	Volume (Bcf)	NYMEX less[a]	Volume (Bcf)	NYMEX plus[a]

Q3-Q4 2010	—	$	—	***5***	$	0.26
2011	45		0.82	12		0.25
2012	43		0.85	—		—
Totals	88	$	0.84	***17***	**$**	***0.25***

(a)weighted average

The company also has the following crude oil swaps in place for 2010 and 2011:

	Open Swaps (mbbls)	Avg. NYMEX Strike Price	Assuming Oil Production (mbbls)	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains (Losses) from Lifted Trades ($ millions)	Total Lifted Gains (Losses) per bbl of Estimated Total Oil Production
Q3 2010	2,300	$ 89.62	—	—	$ (4.1)	—
Q4 2010	2,300	$ 89.62	—	—	$ (4.1)	—
Q3-Q4 2010[(a)]	***4,600***	$ 89.62	***10,700***	***43%***	***$ (8.2)***	***$ (0.76)***
Total 2011[(a)]	3,285	$ 96.09	***34,000***	***10%***	$ 32.9	***$ 0.96***

(a)Certain hedging arrangements include knockout swaps with provisions limiting the counterparty’s exposure below prices of $60.00 covering 2 mmbbls and 1 mmbbls in Q3-Q4 2010 and 2011, respectively.

Note: Not shown above are written call options covering 1 mmbbls of oil production in Q3-Q4 2010 at a weighted average price of $101.25 per bbl for a weighted average discount of $1.93 per bbl and 5 mmbbls of oil production in 2011 at a weighted average price of $88.08 per bbl for a weighted average premium of $3.29 per bbl.

SCHEDULE “B”

CHESAPEAKE’S OUTLOOK AS OF MAY 4, 2010
(PROVIDED FOR REFERENCE ONLY)
NOW SUPERSEDED BY OUTLOOK AS OF AUGUST 3, 2010

Years Ending December 31, 2010 and 2011

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of May 4, 2010, we are using the following key assumptions in our projections for 2010 and 2011.

The primary changes from our February 17, 2010 Outlook are in ***italicized bold*** and are explained as follows:

1)Our production guidance has been increased;

2)Projected effects of changes in our hedging positions have been updated;

3)Equivalent shares outstanding has been updated to reflect exchanges of convertible senior notes; and

4)Our cash flow projections have been updated, including increased drilling capital expenditures to reflect additional drilling on oil and natural gas liquids rich plays and anticipated cost inflation, partially offset by improved drilling efficiencies.

	Year Ending 12/31/2010	Year Ending 12/31/2011
Estimated Production:		
Natural gas – bcf	***874 – 894***	***990 – 1,010***
Oil – mbbls	***17,000***	***26,500***
Natural gas equivalent – bcfe	***976 – 996***	***1,149 – 1,169***
Daily natural gas equivalent midpoint – mmcfe	2,700	***3,175***
Year-over-year (YOY) estimated production increase	8 – 10%	***16 – 18%***
YOY estimated production increase excluding asset sales	15 – 17%	***17 – 19%***
NYMEX Price(a) (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$5.21***	***$6.50***
Oil - $/bbl	***$79.68***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	***$1.82***	***$0.33***
Oil - $/bbl	***$4.05***	***$3.82***
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	***15 – 20%***	***15 – 20%***
Oil - $/bbl	***15 – 20%***	***15 – 20%***
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.85 – 0.95	$0.85 – 0.95
Production taxes (~5% of O&G revenues)	$0.25 – 0.30	$0.30 – 0.35
General and administrative(b)	$0.30 – 0.35	$0.30 – 0.35
Stock-based compensation (non-cash)	$0.09 – 0.11	$0.09 – 0.11
DD&A of natural gas and oil assets	$1.35 – 1.55	$1.35 – 1.55
Depreciation of other assets	$0.20 – 0.25	$0.20 – 0.25
Interest expense(c)	$0.30 – 0.35	$0.30 – 0.35
Other Income per Mcfe:		
Marketing, gathering and compression net margin	$0.07 – 0.09	$0.07 – 0.09
Service operations net margin	$0.04 – 0.06	$0.04 – 0.06
Equity in income of midstream joint venture (CMP)	$0.04 – 0.06	$0.04 – 0.06
Book Tax Rate (all deferred)	38.5%	38.5%
Equivalent Shares Outstanding (in millions):		
Basic	***630 – 635***	***640 – 645***
Diluted	***645 – 650***	***650 – 655***
Operating cash flow before changes in assets and liabilities(d)(e)	***$4,800 – 4,900***	***$5,100 – 5,800***
Drilling and completion costs(f)	***($4,200 – 4,500)***	($4,300 – 4,600)
Dividends, capitalized interest, cash income taxes, etc.	($350 – 400)	($500 – 600)

Note: refer to footnotes on following page

(a)NYMEX natural gas prices have been updated for actual contract prices through May 2010 and NYMEX oil prices have been updated for actual contract prices through March 2010.

(b)Excludes expenses associated with noncash stock compensation.

(c)Does not include gains or losses on interest rate derivatives.

(d)A non-GAAP financial measure. We are unable to provide a 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.

(e)Assumes NYMEX prices of $5.00 to $6.00 per mcf and $80.00 per bbl in 2010 and $6.00 to $7.00 per mcf and $80.00 per bbl in 2011.

(f)Net of drilling carries.

At March 31, 2010, the company had approximately $2.4 billion of cash and cash equivalents and additional borrowing capacity under its two revolving bank credit facilities.

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future natural gas and oil production. These strategies include:

1)Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

2)Collars: These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty's downside exposure below the second put option.

3)Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

4)Call options: Chesapeake sells call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

5)Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these nonqualifying derivatives that occur prior to their maturity (i.e., because of temporary fluctuations in value) are reported currently in the consolidated statement of operations as unrealized gains (losses) within natural gas and oil sales. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in natural gas and oil sales.

The company currently has the following open natural gas swaps in place for 2010 and 2011 and also has the following gains from lifted natural gas trades:

	Open Swaps (Bcf)	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production (Bcf)	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains from Lifted Trades ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q2 2010	***129***	***$ 7.40***			***$ 36.9***	
Q3 2010	***119***	***$ 7.46***			***$ 64.8***	
Q4 2010	***120***	***$ 7.70***			***$ 64.4***	
Q2-Q4 2010[a]	***368***	***$ 7.52***	***675***	***55%***	***$ 166.1***	***$ 0.25***
Total 2011[a]	***157***	***$ 7.91***	***1,000***	***16%***	***$ 59.6***	$ 0.06

(a)Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at prices ranging from $6.50 to $6.75 covering 5 bcf in Q2-Q4 2010 and $5.75 to $6.50 covering 24 bcf in 2011.

The company currently has the following open natural gas collars in place for 2010 and 2011:

	Open Collars (Bcf)	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production (Bcf)	Open Collars as a % of Estimated Total Natural Gas Production
Q2 2010	16	$ 7.04	$ 9.17		
Q3 2010	4	$ 7.60	$ 11.75		
Q4 2010	4	$ 7.60	$ 11.75		
Q2-Q4 2010[a]	***24***	***$ 7.21***	***$ 9.97***	***675***	***4%***
Total 2011	7	$ 7.70	$ 11.50	***1,000***	***1%***

(a)Certain collar arrangements include three-way collars that include written put options with a strike price of $4.35 covering 4 bcf in 2010.

The company currently has the following natural gas written call options in place for 2010 and 2011:

		Avg.	Avg.	Assuming	Call Options as a % of

	Call Options (Bcf)	NYMEX Floor Price	Premium per mcf	Natural Gas Production (Bcf)	Estimated Total Natural Gas Production
Q2 2010	***28***	***$ 9.94***	***$ 1.46***		
Q3 2010	***39***	***$ 9.89***	***$ 1.10***		
Q4 2010	***39***	***$ 10.07***	***$ 1.10***		
Q2-Q4 2010	***106***	***$ 9.97***	***$ 1.20***	***675***	***16%***
Total 2011	***69***	***$ 9.51***	***$ 0.61***	***1,000***	7%

The company has the following natural gas basis protection swaps in place for 2010, 2011 and 2012:

	Non-Appalachia		Appalachia	
	Volume (Bcf)	NYMEX less[a]	Volume (Bcf)	NYMEX plus[a]
Q2-Q4 2010	—	$ —	***8***	$ 0.26
2011	45	0.82	12	0.25
2012	43	0.85	—	—
Totals	88	$ 0.84	***20***	$ 0.26

(a)weighted average

The company also has the following crude oil swaps in place for 2010 and 2011:

	Open Swaps (mbbls)	Avg. NYMEX Strike Price	Assuming Oil Production (mbbls)	Open Swap Positions as a % of Estimated Total Oil Production	Total Gains (Losses) from Lifted Trades ($ millions)	Total Lifted Gains (Losses) per bbl of Estimated Total Oil Production
Q2 2010	2,275	$ 89.62	—	—	$ (4.0)	—
Q3 2010	2,300	$ 89.62	—	—	***$ (4.1)***	—
Q4 2010	2,300	$ 89.62	—	—	***$ (4.1)***	—
Q2-Q4 2010[a]	6,875	$ 89.62	***13,100***	***52%***	***$ (12.2)***	***$ (0.93)***
Total 2011[a]	3,285	$ 96.09	***26,500***	***12%***	***$ 32.9***	***$ 1.24***

(a)Certain hedging arrangements include knockout swaps with provisions limiting the counterparty’s exposure below prices of $60.00 covering 4 mmbbls and 1 mmbbls in Q2-Q4 2010 and 2011, respectively.

Note: Not shown above are written call options covering 1 mmbbls of oil production in Q2-Q4 2010 at a weighted average price of $101.25 per bbl for a weighted average discount of $1.93 per bbl and 3 mmbbls of oil production in 2011 at a weighted average price of $93.13 per bbl for a weighted average premium of $5.34 per bbl.

SOURCE: Chesapeake Energy Corporation

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