News Release

FOR IMMEDIATE RELEASE
JULY 28, 2011

CHESAPEAKE ENERGY CORPORATION REPORTS FINANCIAL AND OPERATIONAL RESULTS FOR THE 2011 SECOND QUARTER

Company Reports 2011 Second Quarter Net Income to Common Stockholders of $467 Million, or $0.68 per Fully Diluted Common Share, on Revenue of $3.3 Billion; Company Reports Adjusted Net Income Available to Common Stockholders of $528 Million, or $0.76 per Fully Diluted Common Share, Adjusted Ebitda of $1.4 Billion and Operating Cash Flow of $1.2 Billion

2011 Second Quarter Average Daily Total Production of 3.049 Bcfe per Day Increases 9% Year over Year and Decreases 2% Sequentially Due to the Sale of Fayetteville Shale Assets and VPP #9; 2011 Second Quarter Liquids Production Increases 62% Year over Year and 19% Sequentially; 2011 Second Quarter Liquids Production Yields 16% of Total Production and 28% of Realized Natural Gas and Liquids Revenue

Proved Reserves Total 16.5 Tcfe; Company Adds New Net Proved Reserves of 2.7 Tcfe Through the Drillbit in the First Half of 2011 at a Drilling and Completion Cost of $1.29 per Mcfe

Company Increases Full-Year 2011 and 2012 Production and Capital Expenditure Outlook; Company Largely Offsets Oilfield Service Inflation Through Its Wholly Owned Oilfield Service Businesses and Its 30% Stake in Frac Tech

Chesapeake Announces a Major New Liquids-Rich Discovery in the Utica Shale in Eastern Ohio

OKLAHOMA CITY, OKLAHOMA, JULY 28, 2011 – Chesapeake Energy Corporation (NYSE:CHK) today announced its 2011 second quarter financial and operational results. For the quarter, Chesapeake reported net income to common stockholders of $467 million ($0.68 per fully diluted common share), operating cash flow of $1.207 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.289 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization) on revenue of $3.318 billion and production of 277 billion cubic feet of natural gas equivalent (bcfe).

The company's 2011 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 2011 second quarter, Chesapeake reported adjusted net income to common stockholders of $528 million ($0.76 per fully diluted common share) and adjusted ebitda of $1.365 billion. The excluded items and their effects on the 2011 second quarter reported results are detailed as follows:

- a net unrealized after-tax mark-to-market gain of $61 million resulting from the company's natural gas, liquids and interest rate hedging programs; and

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- an after-tax loss of $122 million related to purchases of certain of the company's senior notes, a loss on foreign currency derivatives and other items.

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 17 – 21 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2011 second quarter and compares them to results during the 2011 first quarter and the 2010 second quarter.

	Three Months Ended		
	6/30/11	3/31/11	6/30/10
Average daily production (in mmcfe)[(a)]	3,049	3,107	2,789
Natural gas as % of total production	84	87	90
Natural gas production (in bcf)	234.3	243.3	227.2
Average realized natural gas price ($/mcf)[(b)]	5.19	5.31	5.66
Oil and NGL (liquids) production (in mbbls)	7,192	6,048	4,429
Average realized liquids price ($/bbl)[(b)]	65.23	63.20	61.43
Natural gas equivalent production (in bcfe)	277.5	279.6	253.8
Natural gas equivalent realized price ($/mcfe)[(b)]	6.07	5.99	6.14
Marketing, gathering and compression net margin ($/mcfe)[(c)]	.14	.11	.12
Service operations net margin ($/mcfe) [(c)]	.11	.09	.02
Production expenses ($/mcfe)	(.94)	(.85)	(.84)
Production taxes ($/mcfe)	(.17)	(.16)	(.15)
General and administrative costs ($/mcfe)[(d)]	(.38)	(.38)	(.34)
Stock-based compensation ($/mcfe)	(.08)	(.08)	(.08)
DD&A of natural gas and liquids properties ($/mcfe)	(1.32)	(1.28)	(1.34)
D&A of other assets ($/mcfe)	(.23)	(.24)	(.21)
Interest (expense) income ($/mcfe)[(b)]	(.07)	.00	(.13)
Operating cash flow ($ in millions)[(e)]	1,207	1,381	1,304
Operating cash flow ($/mcfe)	4.35	4.94	5.14
Adjusted ebitda ($ in millions)[(f)]	1,365	1,346	1,256
Adjusted ebitda ($/mcfe)	4.92	4.81	4.95
Net income (loss) to common stockholders ($ in millions)	467	(205)	235
Earnings (loss) per share – assuming dilution ($)	.68	(.32)	.37
Adjusted net income to common stockholders ($ in millions)[(g)]	528	518	491
Adjusted earnings per share – assuming dilution ($)	.76	.75	.75

(a) Closed Fayetteville Shale asset sale (which had an average production loss impact of approximately 400 mmcfe per day in the 2011 second quarter) to BHP Billiton on March 31, 2011 and closed VPP #9 sale (which had an average production loss impact of approximately 40 mmcfe per day in the 2011 second quarter) on May 12, 2011.
(b) Includes the effects of realized gains (losses) from hedging, but excludes the effects of unrealized gains (losses) from hedging.
(c) Includes revenue and operating costs and excludes depreciation and amortization of other assets.
(d) Excludes expenses associated with noncash stock-based compensation.
(e) Defined as cash flow provided by operating activities before changes in assets and liabilities.
(f) 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 19.
(g) Defined as net income (loss) available to common stockholders, as adjusted to remove the effects of certain items detailed on page 20.

2011 Second Quarter Average Daily Total Production of 3.049 Bcfe per Day Increases 9% Year over Year and Decreases 2% Sequentially Due to the Sale of Fayetteville Shale Assets and VPP #9; 2011 Second Quarter Liquids Production Increases 62% Year over Year and 19% Sequentially; 2011 Second Quarter Liquids Production Yields 16% of Total Production and 28% of Realized Natural Gas and Liquids Revenue

Chesapeake's daily production for the 2011 second quarter averaged 3.049 bcfe, an increase of 260 million cubic feet of natural gas equivalent (mmcfe), or 9%, over the 2.789 bcfe produced per day in the 2010 second quarter and a decrease of 58 mmcfe, or 2%, from the 3.107 bcfe produced per day in the 2011 first quarter. Adjusted for the sale of the company's Fayetteville Shale assets to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP) on March 31, 2011 (which had an average production loss impact of approximately 400 mmcfe per day in the 2011 second quarter), and the company's ninth volumetric production payment (VPP #9) transaction on May 12, 2011 (which had an average production loss impact of approximately 40 mmcfe per day in the 2011 second quarter), Chesapeake's year over year and sequential daily production growth would have been approximately 700 mmcfe and 380 mmcfe, or 25% and 12%, respectively.

Chesapeake's average daily production of 3.049 bcfe for the 2011 second quarter consisted of 2.575 billion cubic feet of natural gas (bcf) and 79,033 barrels (bbls) of oil and natural gas liquids (collectively, "liquids"). The company's 2011 second quarter production of 277.5 bcfe was comprised of 234.3 bcf of natural gas (84% on a natural gas equivalent basis) and 7.2 million barrels of liquids (mmbbls) (16% on a natural gas equivalent basis). The company's year over year growth rate of natural gas production was 3% and its year over year growth rate of liquids production was 62% before adjustments for asset sales and 20% and 65%, respectively, after adjustments. The company's percentage of revenue from liquids in the 2011 second quarter was 28% of total realized natural gas and liquids revenue compared to 17% in the 2010 second quarter and 23% in the 2011 first quarter.

2011 Second Quarter Average Realized Prices Benefit from Realized Hedging Gains of $407 Million, or $1.46 per Mcfe

Average prices realized during the 2011 second quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $5.19 per thousand cubic feet (mcf) and $65.23 per bbl, for a realized natural gas equivalent price of $6.07 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas hedging activities during the 2011 second quarter generated a $1.93 gain per mcf, while realized losses from liquids hedging activities generated a $6.23 loss per bbl, resulting in 2011 second quarter net realized hedging gains of $407 million, or $1.46 per mcfe.

By comparison, 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 mcf and $61.43 per bbl, for a realized natural gas equivalent price of $6.14 per mcfe. Realized gains from natural gas and liquids hedging activities during the 2010 second quarter generated a $2.43 gain per mcf and a $4.85 gain per bbl, resulting in 2010 second quarter realized hedging gains of $573 million, or $2.26 per mcfe. The company's realized cash hedging gains since January 1, 2006 have been $7.7 billion, or $1.67 per mcfe, on average, for every mcfe produced.

Company Provides Update on Hedging Positions

The following table summarizes Chesapeake's 2011 and 2012 open swap positions as of July 28, 2011. 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 increase or decrease some or all of its hedging positions at any time in the future without notice.

	Natural Gas		Liquids	
Year	% of Forecasted Production	$ NYMEX	% of Forecasted Production	$ NYMEX Oil
3Q – 4Q 2011	79%	$4.79	9%	$100.90
2012	9%	$6.12	3%	$105.03

In addition to the open hedging positions disclosed above, as of July 28, 2011, the company had an additional $501 million and $330 million of net hedging gains on closed contracts and premiums collected on call options that will be realized in 2011 and 2012, respectively, as set forth below.

	Natural Gas			Liquids		
Year	Forecasted Production (bcf)	Gains ($ in millions)	Gains ($/mcf)	Forecasted Production (mbbls)	Gains (Losses) ($ in millions)	Gains (Losses) ($/bbl)
3Q – 4Q 2011	500	$535	$1.07	19,000	$(34)	$(1.80)
2012	1,020	$248	$0.24	55,000	$82	$1.48

Assuming future NYMEX natural gas settlement prices average $4.50 and $5.50 per mcf for the second half of 2011 and for the full year 2012, respectively, and including the effect of the company's open hedges, closed contracts and previously collected call premiums, the company estimates its average NYMEX natural gas prices will be $5.70 and $5.78 per mcf for the second half of 2011 and for the full year 2012, respectively. Additionally, assuming future NYMEX oil settlement prices average $100.00 per bbl for the second half of 2011 and for the full year 2012, the company estimates its average NYMEX oil prices will be $97.09 and $96.07 per bbl for the second half of 2011 and for the full year 2012, respectively. Wellhead prices are further reduced from these estimates by the effect of gathering costs, basis and quality differentials and the effect of lower-priced natural gas liquids.

Details of the company's quarter-end hedging positions, including sold call options, are provided in the company's Form 10-Q and Form 10-K filings with the SEC and current positions are disclosed in summary format in the company's Outlook. The company's updated forecasts for 2011 and 2012 are attached to this release in the Outlook dated July 28, 2011, labeled as Schedule "A," which begins on page 22. The Outlook has been changed from the Outlook dated May 2, 2011, attached as Schedule "B," which begins on page 26, to reflect various updated information.

Proved Natural Gas and Liquids Reserves Decreased by 642 Bcfe, or 4%, in the First Half of 2011 to 16.5 Tcfe Due to the Sale of 2.8 Tcfe of Proved Reserves; Also in the First Half of 2011, Company Adds New Net Proved Reserves Before Sales of 2.7 Tcfe Through the Drillbit at a Drilling and Completion Cost of $1.29 per Mcfe

During the first half of 2011, Chesapeake continued the industry's most active drilling program drilling 759 gross operated wells (480 net wells with an average working interest of 63%) and participating in another 708 gross non-operated wells (104 net wells with an average working interest of 15%). The company's drilling success rate was 98% for company-operated wells and 99% for non-operated wells. During the first half of 2011, Chesapeake's drilling and completion costs of $3.427 billion included the benefit of approximately $1.129 billion of drilling and completion carries from its joint venture partners.

The following table compares Chesapeake's June 30, 2011 proved reserves, the decrease versus its year-end 2010 proved reserves, estimated future net cash flows from proved reserves (discounted at an annual rate of 10% before income taxes (PV-10)), and proved developed percentage based on the trailing 12-month average price required by the reserve reporting rules of the Securities and Exchange Commission (SEC) and the 10-year average NYMEX strip prices at June 30, 2011.

Pricing Method	Natural Gas Price ($/mcf)	Oil Price ($/bbl)	Proved Reserves (tcfe)[a]	Proved Reserves Decrease (bcfe)[b]	Proved Reserves Decrease %[b]	PV-10 (billions)	Proved Developed %
Trailing 12-month average (SEC)[c]	$4.21	$89.86	16.5	642	4%	$16.4	54%
6/30/11 10-year average NYMEX strip[d]	$5.80	$100.24	17.2	401	2%	$27.4	54%

(a) After sales of proved reserves of approximately 2.8 tcfe during the first half of 2011.

(b) Compares proved reserve decrease for the first half of 2011 under comparable pricing methods. At year-end 2010, Chesapeake's proved reserves were 17.1 tcfe using trailing 12-month average prices, which are required by SEC reporting rules, and 17.6 tcfe using the 10-year average NYMEX strip prices at December 31, 2010.

(c) Reserve volumes estimated using SEC reserve recognition standards and pricing assumptions based on the trailing 12-month average first-day-of-the-month prices as of June 30, 2011. This pricing yields estimated "proved reserves" for SEC reporting purposes. Natural gas and liquids volumes estimated under any alternative pricing scenario reflect the sensitivity of proved reserves to a different pricing assumption.

(d) Futures prices represent an unbiased consensus estimate by market participants about the likely prices to be received for future production. Management believes that 10-year average NYMEX strip prices provide a better indicator of the likely economic producibility of the company's proved reserves than the historical 12-month average price.

The following table summarizes Chesapeake's drilling and completion costs for the first half of 2011 using the two pricing methods described above.

	Trailing 12-Month Average (SEC) Pricing ($/mcfe)	6/30/11 10-year Average NYMEX Strip Pricing ($/mcfe)
Drilling and completion costs[a]	$1.29	$1.26

(a) Includes performance-related revisions and excludes price-related revisions. Costs are net of drilling and completion carries paid by the company's joint venture partners.

A complete reconciliation of proved reserves based on these two alternative pricing methods, along with total costs, is presented on pages 13 and 14 of this release.

In addition to the PV-10 value of its proved reserves, the company also has substantial value in its undeveloped leasehold. Furthermore, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other noncurrent assets) was $6.6 billion as of June 30, 2011, an increase of approximately $500 million from December 31, 2010.

Chesapeake's Leasehold and 3-D Seismic Inventories Total 14.5 Million Net Acres and 29.4 Million Acres, Respectively; Risked Unproved Resources in the Company's Inventory Total 109 Tcfe

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (14.5 million net acres) and 3-D seismic (29.4 million acres) in the U.S. The company has also accumulated the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) and now owns a leading position in 12 of what Chesapeake believes are the Top 15 unconventional liquids-rich plays in the U.S. – the Granite Wash, Cleveland, Tonkawa and Mississippian plays in the Anadarko Basin; the Avalon, Bone Spring, Wolfcamp and Wolfberry plays in the Permian Basin; the Eagle Ford Shale in South Texas; the Niobrara Shale in the Powder River and DJ basins; the Bakken/Three Forks in the Williston Basin; and the Utica Shale in the Appalachian Basin.

On its total leasehold inventory, Chesapeake has identified an estimated 17.2 trillion cubic feet of natural gas equivalent (tcfe) of proved reserves (using volume estimates based on the 10-year average NYMEX strip prices at June 30, 2011), 109 tcfe of risked unproved resources and 322 tcfe of unrisked unproved resources. The company is currently using 166 operated drilling rigs to further develop its inventory of approximately 38,400 net risked drillsites. Of Chesapeake's 166 operated rigs, 81 are drilling wells primarily focused on unconventional natural gas plays (including 48 operated rigs utilizing drilling carries), 82 are drilling wells primarily focused on unconventional liquids-rich plays (including 28 operated rigs utilizing drilling carries) and three are drilling conventional natural gas plays. In addition, 163 of the company's 166 operated rigs are drilling horizontal wells.

In recognition of the value gap between liquids and natural gas prices, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise during the past three years to identify, secure and commercialize new unconventional liquids-rich plays. To date, Chesapeake has built leasehold positions and established production in multiple liquids-rich plays on approximately 5.5 million net leasehold acres with 6.5 billion bbls of oil equivalent (bboe) (or 39 tcfe) of risked unproved resources and 24.0 bboe (or 144 tcfe) of unrisked unproved resources based on the company's internal estimates. As a result of its success to date, Chesapeake expects to increase its liquids production through its drilling activities to more than 150,000 bbls per day, or 20%-25% of total production, by year-end 2012 and to more than 250,000 bbls per day, or 30%-35% of total production, by year-end 2015.

The following table summarizes Chesapeake's ownership and activity in its unconventional natural gas plays, its unconventional liquids-rich plays and its other conventional and unconventional plays. Chesapeake uses a probability-weighted statistical approach to estimate the potential number of drillsites and unproved resources associated with such drillsites.

Play Type/Area	CHK Net Acreage (1)	Est. Drilling Density (Acres)	Risk Factor	Risked Net Undrilled Wells	Total Proved Reserves (bcfe) (1)(2)	Risked Unproved Resources (bcfe) (1)	Unrisked Unproved Resources (bcfe) (1)	July 2011 Daily Net Production (mmcfe)	July 2011 Operated Rig Count
Unconventional Natural Gas Plays:									
Marcellus	1,750,000	90	60%	7,710	1,059	37,100	93,600	320	30
Haynesville	495,000	80	30%	4,040	4,157	16,800	25,300	1,085	28
Bossier (3)	190,000	80	60%	970	16	4,000	10,000	15	5
Barnett	220,000	60	25%	1,670	3,831	2,800	3,700	395	16
Pearsall (4)	350,000	160	75%	550	3	2,500	9,800	ND	2
Subtotal	**2,465,000**			**14,940**	**9,066**	**63,200**	**142,400**	**1,815**	**81**
Unconventional Liquids Plays:									
Anadarko Basin (5)	2,035,000	155	70%	4,360	2,506	12,500	33,100	510	35
Eagle Ford	460,000	80	50%	2,830	399	8,100	16,600	50	20
Permian Basin (6)	835,000	160	65%	1,810	302	2,800	9,000	110	12
Powder River and DJ basins (7)	595,000	ND	ND	ND	ND	ND	ND	ND	8
Utica	1,250,000	ND	ND	ND	ND	ND	ND	ND	5
Other	320,000	ND	ND	ND	ND	ND	ND	ND	2
Subtotal	**5,495,000**			**13,670**	**3,224**	**38,900**	**144,000**	**680**	**82**
Other Conventional and Unconventional Plays:	**6,520,000**	**Various**	**Various**	**9,790**	**4,910**	**7,100**	**35,600**	**640**	**3**
Total	**14,480,000**			**38,400**	**17,200**	**109,200**	**322,000**	**3,135**	**166**

Note: ND denotes "not disclosed"
(1) As of June 30, 2011, pro forma for recent leasehold transactions
(2) Based on 10-year average NYMEX strip prices at June 30, 2011
(3) Bossier Shale acreage overlaps with Haynesville Shale acreage and is excluded from the sub-totals to avoid double counting of acreage
(4) Pearsall Shale acreage overlaps with Eagle Ford Shale acreage and is excluded from the sub-totals to avoid double counting of acreage
(5) Includes Granite Wash, Cleveland, Tonkawa and Mississippian plays
(6) Includes various Delaware and Midland basin plays, including Wolfcamp, Avalon, Bone Spring and Wolfberry
(7) Includes Niobrara, Frontier, Codell and Greenhorn plays

Company Increases Full-Year 2011 and 2012 Production and Capital Expenditure Outlook; Company Largely Offsets Oilfield Service Inflation Through Its Wholly Owned Oilfield Service Businesses and Its 30% Stake in Frac Tech

As a result of continued strong drilling results, particularly in the Haynesville Shale and the Marcellus Shale (where Chesapeake has recently increased its expected estimated ultimate per well recoveries to 5.75 bcfe from 5.25 bcfe), Chesapeake has increased its production forecast for the full-year 2011 and 2012 to approximately 1.170 tcfe and 1.350 tcfe, respectively, and now anticipates delivering approximately 30% production growth for the two-year period ending December 31, 2012, a 20% increase from its prior forecasted growth rate of 25% as projected in the company's 25/25 Plan announced in January 2011. Chesapeake's full-year 2011 liquids production forecast range has been reduced by 2 mmbbls, or 6%, to 31-33 mmbbls due to short-term infrastructure and logistical constraints in many of its liquids-rich plays, which Chesapeake expects to resolve in the coming months. As a result, the company has increased the lower end of its 2012 liquids production forecast range by an offsetting 2 mmbbls to 53 mmbbls.

Because of persistent and significant oilfield service inflation and a more accelerated drilling program in the Utica Shale play, Chesapeake has increased its planned drilling and completion capital expenditure budget for each of full-year 2011 and 2012 by $500 million to a range of $6.0-$6.5 billion in each year.

Chesapeake has uniquely been able to offset a significant portion of recent oilfield service inflation though its vertical integration strategy and ownership of subsidiary companies that own drilling rigs (Nomac Drilling), pressure pumping equipment (Performance Technologies), rental tools (Great Plains), trucking equipment (Thunder Oilfield), compression manufacturing equipment (Compass) and a variety of other oilfield services, all of which are organized under Chesapeake's wholly owned subsidiary, Chesapeake Oilfield Services, L.L.C. (COS). In aggregate, Chesapeake projects that if these oilfield service businesses were viewed on a standalone basis, operating cash flow from these businesses would be an estimated $600 million in 2012. In addition, COS owns a 30% interest in Frac Tech Services, LLC, the fourth-largest onshore pressure pumping and well stimulation company in the U.S. Based on comparable public company trading multiples, the company believes its stakes in COS and Frac Tech are worth in excess of $7.0 billion. Chesapeake is considering options to monetize a portion of its oilfield service assets to create a cash offset to the oilfield inflation it has experienced in 2011 and expects to experience again in 2012.

Chesapeake Announces a Major New Liquids-Rich Discovery in the Utica Shale in Eastern Ohio

Having achieved successful results from recent drilling activities in eastern Ohio, Chesapeake is announcing the discovery of a major new liquids-rich play in the Utica Shale. Based on its proprietary geoscientific, petrophysical and engineering research during the past two years and the results of six horizontal and nine vertical wells it has drilled, Chesapeake believes that its industry-leading 1.25 million net leasehold acres in the Utica Shale play could be worth $15 - $20 billion in increased value to the company. Chesapeake's dataset on the Utica Shale includes approximately 2,000 well logs, full-suite petrophysical data on approximately 200 wells, 3,200 feet of proprietary core samples from nine wells and production results from three wells. As a result of its analysis, the company believes the Utica Shale will be characterized by a western oil phase, a central wet gas phase and an eastern dry gas phase and is likely most analogous, but economically superior to, the Eagle Ford Shale in South Texas.

Chesapeake is currently drilling in the Utica Shale with five operated rigs to further evaluate and develop its leasehold and anticipates increasing its rig count to eight by the end of 2011 and reaching at least a range of 16-20 rigs by year-end 2012. Also, the company believes that its leasehold position in the Utica Shale will support a drilling effort of at least 40 rigs by year-end 2014. Chesapeake is currently conducting a competitive process to monetize a portion of its Utica Shale leasehold position, which will be through an industry joint venture process or through a number of other monetization alternatives. The company anticipates completing a Utica Shale transaction in the 2011 fourth quarter.

Conference Call Information

A conference call to discuss this release has been scheduled for Friday, July 29, 2011, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-312-0417** or toll-free **888-599-8685**. The passcode for the call is **5165869**. 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 July 29, 2011 through midnight EDT on August 12, 2011. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **5165869**. The conference call will also be webcast live on 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 news 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 estimates of natural gas and liquids reserves and resources, expected natural gas and liquids production and future expenses, assumptions regarding future natural gas and oil prices, planned drilling activity and drilling and completion costs, anticipated asset monetizations, estimates of asset values, projected cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures of the estimated realized effects of our current hedging positions on future natural gas and liquids sales are based upon market prices that 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 news 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 2010 Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2011. 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 liquids 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 liquids reserves and projecting future rates of production and the amount and timing of development expenditures; 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 liquids sales, the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; 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 revenues and 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.

The SEC requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of natural gas and liquids that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. In this news release, we use the terms "risked and unrisked unproved resources" to describe Chesapeake's internal estimates of volumes of natural gas and liquids that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. These are broader descriptions of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. Estimates of unproved resources are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. We believe our estimates of unproved resources are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates. The company calculates the standardized measure of future net cash flows of proved reserves only at year end because applicable income tax information on properties, including recently acquired natural gas and liquids interests, is not readily available at other times during the year. As a result, the company is not able to reconcile interim period-end PV-10 values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects. Year-end standardized measure calculations are provided in the financial statement notes in our annual reports on Form 10-K.

Chesapeake Energy Corporation is the second-largest producer of natural gas, a Top 15 producer of oil and natural gas liquids 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, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Bakken/Three Forks and Utica unconventional liquids plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Chesapeake's stock is listed on the New York Stock Exchange under the symbol CHK. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and press releases.

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

THREE MONTHS ENDED:	June 30, 2011		June 30, 2010	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas and liquids sales	1,792	6.46	1,161	4.57
Marketing, gathering and compression sales	1,404	5.06	793	3.13
Service operations revenue	122	0.44	58	0.23
Total Revenues	3,318	11.96	2,012	7.93
OPERATING COSTS:				
Production expenses	262	0.94	213	0.84
Production taxes	46	0.17	37	0.15
General and administrative expenses	130	0.46	106	0.41
Marketing, gathering and compression expenses	1,366	4.92	763	3.01
Service operations expense	92	0.33	53	0.21
Natural gas and liquids depreciation, depletion and amortization	366	1.32	340	1.34
Depreciation and amortization of other assets	63	0.23	53	0.21
Losses on sales of other property and equipment	4	0.02	—	—
Other impairments	4	0.02	—	—
Total Operating Costs	2,333	8.41	1,565	6.17
INCOME FROM OPERATIONS	985	3.55	447	1.76
OTHER INCOME (EXPENSE):				
Interest (expense) income	(25)	(0.09)	16	0.06
Earnings from equity investees	47	0.17	27	0.11
Losses on purchases or exchanges of debt	(174)	(0.63)	(69)	(0.27)
Other income (expense)	2	0.01	(7)	(0.03)
Total Other Income (Expense)	(150)	(0.54)	(33)	(0.13)
INCOME BEFORE INCOME TAXES	835	3.01	414	1.63
INCOME TAX EXPENSE:				
Current income taxes	6	0.02	5	0.02
Deferred income taxes	319	1.15	154	0.61
Total Income Tax Expense	325	1.17	159	0.63
NET INCOME	510	1.84	255	1.00
Preferred stock dividends	(43)	(0.16)	(20)	(0.07)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	467	1.68	235	0.93
EARNINGS PER COMMON SHARE:				
Basic	$ 0.74		$ 0.37	
Diluted	$ 0.68		$ 0.37	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	635		631	
Diluted	751		635	

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

SIX MONTHS ENDED:	June 30, 2011		June 30, 2010	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas and liquids sales	2,286	4.10	3,059	6.29
Marketing, gathering and compression sales	2,421	4.35	1,637	3.36
Service operations revenue	223	0.40	114	0.24
Total Revenues	4,930	8.85	4,810	9.89
OPERATING COSTS:				
Production expenses	500	0.90	421	0.86
Production taxes	91	0.16	85	0.18
General and administrative expenses	259	0.46	215	0.44
Marketing, gathering and compression expenses	2,352	4.22	1,578	3.24
Service operations expense	169	0.30	102	0.21
Natural gas and liquids depreciation, depletion and amortization	724	1.30	647	1.33
Depreciation and amortization of other assets	131	0.24	103	0.21
Gains on sales of other property and equipment	(1)	—	—	—
Other impairments	4	0.01	—	—
Total Operating Costs	4,229	7.59	3,151	6.47
INCOME FROM OPERATIONS	701	1.26	1,659	3.42
OTHER INCOME (EXPENSE):				
Interest expense	(33)	(0.06)	(9)	(0.02)
Earnings from equity investees	72	0.13	39	0.08
Losses on purchases or exchanges of debt	(176)	(0.32)	(71)	(0.15)
Other income (expense)	5	0.01	(4)	(0.01)
Total Other Income (Expense)	(132)	(0.24)	(45)	(0.10)
INCOME BEFORE INCOME TAXES	569	1.02	1,614	3.32
INCOME TAX EXPENSE:				
Current income taxes	12	0.02	5	0.01
Deferred income taxes	210	0.38	616	1.27
Total Income Tax Expense	222	0.40	621	1.28
NET INCOME	347	0.62	993	2.04
Preferred stock dividends	(85)	(0.15)	(25)	(0.05)
NET INCOME AVAILABLE TO COMMON STOCKHOLDERS	262	0.47	968	1.99
EARNINGS PER COMMON SHARE:				
Basic	$ 0.41		$ 1.54	
Diluted	$ 0.41		$ 1.49	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	635		630	
Diluted	645		665	

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

	June 30, 2011	December 31, 2010
Cash and cash equivalents	$ 109	$ 102
Other current assets	3,017	3,164
Total Current Assets	3,126	3,266
Property and equipment (net)	32,052	32,378
Other assets	1,478	1,535
Total Assets	$ 36,656	$ 37,179
Current liabilities	$ 5,728	$ 4,490
Long-term debt, net of discounts [(a)]	10,047	12,640
Asset retirement obligations	305	301
Other long-term liabilities	2,611	2,100
Deferred tax liability	2,482	2,384
Total Liabilities	21,173	21,915
Stockholders' Equity	15,483	15,264
Total Liabilities & Stockholders' Equity	$ 36,656	$ 37,179
Common Shares Outstanding (in millions)	658	654

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

	June 30, 2011	% of Total Book Capitalization	December 31, 2010	% of Total Book Capitalization
Total debt, net of cash [(a)]	$ 9,938	39%	$ 12,538	45%
Stockholders' equity	15,483	61%	15,264	55%
Total	$ 25,421	100%	$ 27,802	100%

(a) At June 30, 2011, the company had $1.710 billion of borrowings under its $4.0 billion corporate revolving bank credit facility and $104.2 million of borrowings under its $600 million midstream revolving bank credit facility.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2011 ADDITIONS TO NATURAL GAS AND LIQUIDS PROPERTIES
BASED ON SEC PRICING OF TRAILING 12-MONTH AVERAGE PRICES AT JUNE 30, 2011
($ in millions, except per-unit data)
(unaudited)

	Proved Reserves		
	Cost	Bcfe [(a)]	$/Mcfe
Drilling and completion costs[(b)]	$ 3,427	2,652[(c)]	1.29
Acquisition of proved properties	35	28	1.26
Sale of proved properties	(2,613)	(2,760)	0.95
Drilling and completion costs, net of proved property divestitures	849	(80)	(10.61)
Revisions – price	—	(5)	—
Acquisition of unproved properties	1,990	—	—
Sale of unproved properties	(3,478)	—	—
Net unproved properties acquisition	(1,488)	—	—
Capitalized interest on unproved properties	379	—	—
Geological and geophysical costs	103	—	—
Capitalized interest and geological and geophysical costs	482	—	—
Subtotal	(157)	(85)	1.84
Asset retirement obligations and other	(5)	—	—
Total costs	$ (162)	(85)	1.91

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
SIX MONTHS ENDED JUNE 30, 2011
BASED ON SEC PRICING OF TRAILING 12-MONTH AVERAGE PRICES AT JUNE 30, 2011
(unaudited)

	Bcfe[(a)]
Beginning balance, 01/01/11	17,096
Production	(557)
Acquisitions	28
Divestitures	(2,760)
Revisions – changes to previous estimates	145
Revisions – price	(5)
Extensions and discoveries	2,507
Ending balance, 06/30/11	16,454
Proved reserves growth rate	(4)%
Proved developed reserves	8,922
Proved developed reserves percentage	54%
PV-10 ($ in billions) [(a)]	$16.4

(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 June 30, 2011, of $4.21 per mcf of natural gas and $89.86 per bbl of oil, before field differential adjustments.

(b) Net of drilling and completion carries of $1.129 billion associated with the Statoil, Total, CNOOC-Eagle Ford and CNOOC-Niobrara joint venture agreements.

(c) Includes 145 bcfe of positive revisions resulting from changes to previous estimates and excludes downward revisions of 5 bcfe resulting from lower natural gas prices using the average first-day-of-the-month price for the twelve months ended June 30, 2011, compared to the twelve months ended December 31, 2010.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2011 ADDITIONS TO NATURAL GAS AND LIQUIDS PROPERTIES
BASED ON 10-YEAR AVERAGE NYMEX STRIP PRICES AT JUNE 30, 2011
($ in millions, except per-unit data)
(unaudited)

	Proved Reserves		
	Cost	Bcfe [a]	$/Mcfe
Drilling and completion costs [b]	$ 3,427	2,715 [c]	1.26
Acquisition of proved properties	35	28	1.26
Sale of proved properties	(2,613)	(2,760)	0.95
Drilling and completion costs, net of proved property divestitures	849	(17)	(49.94)
Revisions – price	—	173	—
Acquisition of unproved properties	1,990	—	—
Sale of unproved properties	(3,478)	—	—
Net unproved properties acquisition	(1,488)	—	—
Capitalized interest on unproved properties	379	—	—
Geological and geophysical costs	103	—	—
Capitalized interest and geological and geophysical costs	482	—	—
Subtotal	(157)	156	(1.00)
Asset retirement obligations and other	(5)	—	—
Total costs	$ (162)	156	(1.04)

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
SIX MONTHS ENDED JUNE 30, 2011
BASED ON 10-YEAR AVERAGE NYMEX STRIP PRICES AT JUNE 30, 2011
(unaudited)

	Bcfe [a]
Beginning balance, 01/01/11	17,605
Production	(557)
Acquisitions	28
Divestitures	(2,760)
Revisions – changes to previous estimates	446
Revisions – price	173
Extensions and discoveries	2,269
Ending balance, 06/30/11	17,204
Proved reserves growth rate	(2)%
Proved developed reserves	9,372
Proved developed reserves percentage	54%
PV-10 ($ in billions) [a]	$27.4

(a) Reserve volumes and PV-10 value estimated using SEC reserve recognition standards and 10-year average NYMEX strip prices as of June 30, 2011 of $5.80 per mcf of natural gas and $100.24 per bbl of oil, before field differential adjustments. Futures prices, such as the 10-year average NYMEX strip prices, represent an unbiased consensus estimate by market participants about the likely prices to be received for our future production. Chesapeake uses such forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. Chesapeake believes these prices are better indicators of the likely economic producibility of proved reserves than the trailing 12-month average price required by the SEC's reporting rule.

(b) Net of drilling and completion carries of $1.129 billion associated with the Statoil, Total, CNOOC-Eagle Ford and CNOOC-Niobrara joint venture agreements.

(c) Includes 446 bcfe of positive revisions resulting from changes to previous estimates and excludes positive revisions of 173 bcfe resulting from higher natural gas and oil prices using 10-year average NYMEX strip prices as of June 30, 2011, compared to NYMEX strip prices as of December 31, 2010.

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

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2011	2010	2011	2010
Natural Gas and Liquids Sales ($ in millions):				
Natural gas sales	$ 764	$ 733	$ 1,552	$ 1,676
Natural gas derivatives – realized gains (losses)	452	552	958	931
Natural gas derivatives – unrealized gains (losses)	(115)	(195)	(665)	219
Total Natural Gas Sales	1,101	1,090	1,845	2,826
Liquids sales	514	251	913	493
Oil derivatives – realized gains (losses)	(45)	21	(62)	41
Oil derivatives – unrealized gains (losses)	222	(201)	(410)	(301)
Total Liquids Sales	691	71	441	233
Total Natural Gas and Liquids Sales	$ 1,792	$ 1,161	$ 2,286	$ 3,059
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 3.26	$ 3.23	$ 3.25	$ 3.84
Liquids ($ per bbl)	$ 71.46	$ 56.58	$ 69.00	$ 59.38
Natural gas equivalent ($ per mcfe)	$ 4.61	$ 3.88	$ 4.43	$ 4.46
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 5.19	$ 5.66	$ 5.25	$ 5.97
Liquids ($ per bbl)	$ 65.23	$ 61.43	$ 64.30	$ 64.35
Natural gas equivalent ($ per mcfe)	$ 6.07	$ 6.14	$ 6.03	$ 6.46
Interest Expense (Income) ($ in millions):				
Interest [(a)]	$ 6	$ 35	$ 15	$ 90
Derivatives – realized (gains) losses	13	(2)	6	(4)
Derivatives – unrealized (gains) losses	6	(49)	12	(77)
Total Interest Expense (Income)	$ 25	$ (16)	$ 33	$ 9

(a) Net of amounts capitalized.

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

THREE MONTHS ENDED:	June 30, 2011	June 30, 2010
Beginning cash	$ 849	$ 516
Cash provided by operating activities	$ 1,375	$ 1,795
Cash flows from investing activities:		
Exploration and development of natural gas and liquids properties	$ (1,703)	$ (1,311)
Acquisitions of proved and unproved properties	(1,271)	(1,825)
Divestitures of proved and unproved properties	991	709
Investments, net	208	(103)
Other property and equipment, net	(673)	(150)
Other	(18)	(38)
Total cash used in investing activities	$ (2,466)	$ (2,718)
Cash provided by financing activities	$ 351	$ 1,008
Ending cash	$ 109	$ 601

SIX MONTHS ENDED:	June 30, 2011	June 30, 2010
Beginning cash	$ 102	$ 307
Cash provided by operating activities	$ 2,093	$ 2,978
Cash flows from investing activities:		
Exploration and development of natural gas and liquids properties	$ (3,395)	$ (2,331)
Acquisitions of proved and unproved properties	(2,529)	(2,855)
Divestitures of proved and unproved properties	6,173	1,933
Investments, net	212	(109)
Other property and equipment, net	(676)	(373)
Other	(25)	3
Total cash used in investing activities	$ (240)	$ (3,732)
Cash provided by (used in) financing activities	$ (1,846)	$ 1,048
Ending cash	$ 109	$ 601

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

THREE MONTHS ENDED:	June 30, 2011	March 31, 2011	June 30, 2010
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,375	$ 718	$ 1,795
Changes in assets and liabilities	(168)	663	(491)
OPERATING CASH FLOW [(a)]	$ 1,207	$ 1,381	$ 1,304

THREE MONTHS ENDED:	June 30, 2011	March 31, 2011	June 30, 2010
NET INCOME (LOSS)	$ 510	$ (162)	$ 255
Income tax expense (benefit)	325	(104)	159
Interest expense (income)	25	7	(16)
Depreciation and amortization of other assets	63	68	53
Natural gas and liquids depreciation, depletion and Amortization	366	358	340
EBITDA [(b)]	$ 1,289	$ 167	$ 791

THREE MONTHS ENDED:	June 30, 2011	March 31, 2011	June 30, 2010
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,375	$ 718	$ 1,795
Changes in assets and liabilities	(168)	663	(491)
Interest expense (income)	25	7	(16)
Unrealized gains (losses) on natural gas and oil derivatives	106	(1,182)	(396)
Gains (losses) on equity investments	19	5	(48)
Stock-based compensation	(39)	(40)	(35)
Other items	(29)	(4)	(18)
EBITDA [(b)]	$ 1,289	$ 167	$ 791

(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. 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, 2011	June 30, 2010
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,093	$ 2,978
Changes in assets and liabilities	495	(414)
OPERATING CASH FLOW [(a)]	$ 2,588	$ 2,564

SIX MONTHS ENDED:	June 30, 2011	June 30, 2010
NET INCOME	$ 347	$ 993
Income tax expense	222	621
Interest expense	33	9
Depreciation and amortization of other assets	131	103
Natural gas and liquids depreciation, depletion and amortization	724	647
EBITDA [(b)]	$ 1,457	$ 2,373

SIX MONTHS ENDED:	June 30, 2011	June 30, 2010
CASH PROVIDED BY OPERATING ACTIVITIES	$ 2,093	$ 2,978
Changes in assets and liabilities	495	(414)
Interest expense	33	9
Unrealized losses on natural gas and oil derivatives	(1,075)	(82)
Losses on equity investments	24	(35)
Stock-based compensation	(79)	(67)
Other items	(34)	(16)
EBITDA [(b)]	$ 1,457	$ 2,373

(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 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. 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, 2011**	**March 31, 2011**	**June 30, 2010**
EBITDA	$ 1,289	$ 167	$ 791
Adjustments:			
Unrealized (gains) losses on natural gas and oil derivatives	(106)	1,182	396
Losses on purchases or exchanges of debt	174	2	69
(Gains) losses on sales of other property and equipment	4	(5)	—
Other impairments	4	—	—
Adjusted EBITDA [(a)]	$ 1,365	$ 1,346	$ 1,256

(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, 2011**	**June 30, 2010**
EBITDA	$ 1,457	$ 2,373
Adjustments:		
Unrealized losses on natural gas and oil derivatives	1,075	82
Losses on purchases or exchanges of debt	176	71
Gains on sales of other property and equipment	(1)	—
Other impairments	4	—
Adjusted EBITDA [(a)]	$ 2,711	$ 2,526

(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, 2011	March 31, 2011	June 30, 2010
Net income (loss) available to common stockholders	$ 467	$ (205)	$ 235
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	(61)	725	214
Losses on purchases or exchanges of debt, net of tax	106	1	42
(Gains) losses on sales of other property and equipment, net of tax	3	(3)	—
Other impairments, net of tax	2	—	—
Loss on foreign currency derivatives	11	—	—
Adjusted net income available to common stockholders [(a)]	528	518	491
Preferred stock dividends	43	43	20
Total adjusted net income	$ 571	$ 561	$ 511
Weighted average fully diluted shares outstanding [(b)]	751	750	682
Adjusted earnings per share assuming dilution [(a)]	$ 0.76	$ 0.75	$ 0.75

(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, 2011**		**June 30, 2010**
Net income available to common stockholders	$	262	$	968
Adjustments:				
Unrealized losses on derivatives, net of tax		663		3
Losses on purchases or exchanges of debt, net of tax		107		44
Other impairments, net of tax		2		—
Loss on foreign currency derivatives		11		—
Adjusted net income available to common stockholders [(a)]		1,045		1,015
Preferred stock dividends		85		25
Total adjusted net income	$	1,130	$	1,040
Weighted average fully diluted shares outstanding [(b)]		751		665
Adjusted earnings per share assuming dilution [(a)]	$	1.51	$	1.56

(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 JULY 28, 2011

Years Ending December 31, 2011 and 2012

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of July 28, 2011, we are using the following key assumptions in our projections for 2011 and 2012.

The primary changes from our May 2, 2011 Outlook are in ***italicized bold*** and are explained as follows:
1) Our production guidance has been updated;
2) Projected effects of changes in our hedging positions have been updated;
3) Certain cost assumptions have been updated; and
4) Our cash flow projections have been updated, including increased drilling and completion costs.

	Year Ending 12/31/2011	Year Ending 12/31/2012
Estimated Production:		
Natural gas – bcf	***970 – 990***	***1,000 – 1,040***
Liquids – mbbls	***31,000 – 33,000***	***53,000 – 57,000***
Natural gas equivalent – bcfe	***1,156 – 1,188***	***1,318 – 1,382***
Daily natural gas equivalent midpoint – mmcfe	***3,200***	***3,700***
Year over year (YOY) estimated production increase	***12 – 15%***	***12 - 18%***
YOY estimated production increase excluding asset sales	***23 – 26%***	***13 - 19%***
NYMEX Price[(a)] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$4.34***	$5.50
Oil - $/bbl	***$99.15***	$100.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	$1.60	***$0.28***
Liquids - $/bbl	***$(3.65)***	***$(3.93)***
Estimated Gathering/Marketing/Transportation Differentials to NYMEX Prices:		
Natural gas - $/mcf	$0.90 – $1.10	$0.90 – $1.10
Liquids - $/bbl[(b)]	$30.00 – $35.00	$30.00 – $35.00
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.90 – 1.00	$0.90 – 1.00
Production taxes (~ 5% of O&G revenues)	$0.25 – 0.30	$0.25 – 0.30
General and administrative[(c)]	***$0.36 – 0.41***	***$0.36 – 0.41***
Stock-based compensation (non-cash)	$0.07 – 0.09	$0.07 – 0.09
DD&A of natural gas and liquids assets	***$1.25 – 1.40***	***$1.25 – 1.40***
Depreciation of other assets	$0.20 – 0.25	$0.20 – 0.25
Interest expense[(d)]	$0.05 – 0.10	$0.05 – 0.10
Other Income per Mcfe:		
Marketing, gathering and compression net margin	***$0.12 – 0.14***	***$0.12 – 0.14***
Service operations net margin	***$0.09 – 0.11***	***$0.15 – 0.20***
Other income (including equity investments)	$0.06 – 0.08	$0.06 – 0.08
Book Tax Rate	39%	39%
Equivalent Shares Outstanding (in millions):		
Basic	640 – 645	647 – 652
Diluted	750 – 755	760 – 765
Operating cash flow before changes in assets and liabilities[(e)(f)]	***$5,100 – 5,200***	***$6,000 – 6,800***
Drilling and completion costs, net of joint venture carries	***($6,000 – 6,500)***	***($6,000 – 6,500)***

Note: please refer to footnotes on following page

a) NYMEX natural gas prices have been updated for actual contract prices through July 2011 and NYMEX oil prices have been updated for actual contract prices through June 2011.
b) Differentials include effects of natural gas liquids.
c) Excludes expenses associated with noncash stock compensation.
d) Does not include gains or losses on interest rate derivatives.
e) 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.
f) Assumes NYMEX prices of $4.00 to $5.00 per mcf and $100.00 per bbl in 2011 and $5.00 to $6.00 per mcf and $100.00 per bbl in 2012.

Commodity Hedging Activities

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. The company utilizes the following types of natural gas and oil derivative instruments:

1) Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
2) Call options: Chesapeake sells call options in exchange for a premium from the counterparty. 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.
3) Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market prices falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.
4) 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 price.
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. Since the latter half of 2009 through June 2011, the company has taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to its counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with strike prices above the then current market price. This effectively allowed the company to sell out-year volatility through call options at terms acceptable to Chesapeake in exchange for natural gas swaps with fixed prices in excess of the market price at the time.

Gains or losses from commodity derivative transactions are reflected as adjustments to natural gas and liquids sales. All realized gains (losses) from natural gas and oil derivatives are included in natural gas and liquids sales in the month of related production. In accordance with generally accepted accounting principles, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and liquids sales as unrealized gains (losses). Realized gains (losses) are comprised of settled trades related to the production periods being reported. Unrealized gains (losses) are comprised of both temporary fluctuations in the mark-to-market values of nonqualifying trades and settled values of nonqualifying derivatives related to future production periods.

At July 28, 2011, the company has the following open natural gas swaps in place for 2011 and 2012. In addition, the company currently has $630 million of net hedging gains related to closed natural gas contracts and premiums collected on call options for future production periods.

	Open Swaps (Bcf)	Avg. NYMEX Price of Open Swaps	Forecasted Natural Gas Production (Bcf)	Open Swap Positions as a % of Forecasted Natural Gas Production	Total Gains (Losses) from Closed Trades and Collected Call Premiums ($millions)	Total Gains from Closed Trades and Collected Call Premiums per mcf of Forecasted Natural Gas Production
Q3 2011	***200***	***$ 4.81***			***$ 285***	
Q4 2011	***197***	***$ 4.78***			***$ 250***	
Total 2011	***397***	***$ 4.79***	***500***	***79%***	***$ 535***	***$ 1.07***
Total 2012	***94***	***$ 6.12***	***1,020***	***9%***	$ ***248***	***$ 0.24***
Total 2013					***$ 21***	
Total 2014					***$ (32)***	
Total 2015					***$ (46)***	
Total 2016 – 2020					***$ (96)***	

The company currently has the following natural gas written call options in place for 2011 through 2020:

	Call Options (Bcf)	Avg. NYMEX Strike Price	Forecasted Natural Gas Production (Bcf)	Call Options as a % of Forecasted Natural Gas Production
Total 2012	161	$ 6.54	***1,020***	16%
Total 2013	***415***	$ 6.44		
Total 2014	330	$ 6.43		
Total 2015	226	$ 6.31		
Total 2016 – 2020	***393***	***$ 7.93***		

The company has the following natural gas basis protection swaps in place for 2011 through 2022:

	Non-Appalachia		Appalachia	
	Volume (Bcf)	Avg. NYMEX less	Volume (Bcf)	Avg. NYMEX plus
2011	***26***	$ 0.82	***25***	$ 0.14
2012	51	$ 0.78	—	$ —
2013 - 2022	29	$ 0.69	—	$ —
Totals	***106***	$ 0.77	***25***	$ 0.14

At July 28, 2011, the company has the following open crude oil swaps in place for 2011 and 2012. In addition, the company has $60 million of net hedging gains related to closed crude oil contracts and premiums collected on call options for future production periods.

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Forecasted Liquids Production (mbbls)	Open Swap Positions as a % of Forecasted Liquids Production	Total Gains (Losses) from Closed Trades and Collected Call Premiums ($millions)	Total Gains (Losses) from Closed Trades and Collected Call Premiums per bbl of Forecasted Liquids Production
Q3 2011	***828***	***$ 100.90***	—	—	***$ (17)***	
Q4 2011	***828***	***$ 100.90***	—	—	***$ (17)***	
Total 2011[(a)]	***1,656***	***$ 100.90***	***19,000***	***9%***	***$ (34)***	***$ (1.80)***
Total 2012[(a)]	***1,830***	***$ 105.03***	**55,000**	***3%***	***$ 82***	***$ 1.48***
Total 2013					$ 6	
Total 2014					***$ (197)***	
Total 2015					***$ 145***	
Total 2016 – 2020					***$ 58***	

(a) Certain hedging contracts include knockout swaps with provisions limiting the counterparty's exposure below prices of $60.00 covering 0.6 mmbbls in 2011 and 0.7 mmbbls in 2012.

The company currently has the following crude oil written call options in place for 2011 through 2017:

	Call Options (mbbls)	Avg. NYMEX Strike Price	Forecasted Liquids Production (mbbls)	Call Options as a % of Forecasted Liquids Production
Q3 2011	1,840	$ ***110.00***		
Q4 2011	1,840	$ ***110.00***		
Total 2011	***3,680***	$ ***110.00***	***19,000***	***19%***
Total 2012	22,139	$ 87.93	**55,000**	**40%**
Total 2013	14,564	$ 87.20		
Total 2014	8,707	$ 87.72		
Total 2015	***11,226***	***$ 92.00***		
Total 2016 – 2017	***14,424***	$ ***89.75***		

SCHEDULE "B"
CHESAPEAKE'S OUTLOOK AS OF MAY 2, 2011
(PROVIDED FOR REFERENCE ONLY)
NOW SUPERSEDED BY OUTLOOK AS OF JULY 28, 2011

Years Ending December 31, 2011 and 2012

Our policy is to periodically provide guidance on certain factors that affect our future financial performance. As of May 2, 2011, we are using the following key assumptions in our projections for 2011 and 2012.

The primary changes from our February 22, 2011 Outlook are in ***italicized bold*** and are explained as follows:
1) Projected effects of changes in our hedging positions have been updated;
2) Our NYMEX oil price assumptions for gathering/marketing/transportation differentials have been updated;
3) Certain cost assumptions have been updated; and
4) Our cash flow projections have been updated, including increased drilling and completion costs.

Note: Projected production volumes have incorporated the loss of production volumes from the closed divestiture of the Fayetteville assets and the anticipated closing of VPP #9 in the 2011 second quarter.

	Year Ending 12/31/2011	Year Ending 12/31/2012
Estimated Production:		
Natural gas – bcf	900 – 930	960 – 1,000
Oil – mbbls	32,000 – 36,000	51,000 – 57,000
Natural gas equivalent – bcfe	1,092 – 1,146	1,266 – 1,342
Daily natural gas equivalent midpoint – mmcfe	3,065	3,560
Year over year (YOY) estimated production increase	6 – 11%	13 - 20%
YOY estimated production increase excluding asset sales	17 – 22%	17 - 24%
NYMEX Price[a] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$4.38***	$5.50
Oil - $/bbl	***$98.53***	***$100.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	***$1.60***	***$0.10***
Oil - $/bbl	***$(2.31)***	***$(4.20)***
Estimated Gathering/Marketing/Transportation Differentials to NYMEX Prices:		
Natural gas - $/mcf	$0.90 – $1.10	$0.90 – $1.10
Oil - $/bbl[b]	***$30.00 – $35.00***	***$30.00 – $35.00***
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.90 – 1.00	$0.90 – 1.00
Production taxes (~ 5% of O&G revenues)	$0.25 – 0.30	$0.25 – 0.30
General and administrative[c]	$0.34 – 0.39	$0.34 – 0.39
Stock-based compensation (non-cash)	$0.07 – 0.09	$0.07 – 0.09
DD&A of natural gas and oil assets	$1.15 – 1.30	$1.15 – 1.30
Depreciation of other assets	$0.20 – 0.25	$0.20 – 0.25
Interest expense[d]	$0.05 – 0.10	$0.05 – 0.10
Other Income per Mcfe:		
Marketing, gathering and compression net margin	$0.09 – 0.11	$0.09 – 0.11
Service operations net margin	***$0.06 – 0.08***	***$0.08 – 0.10***
Other income (including equity investments)	$0.06 – 0.08	$0.06 – 0.08
Book Tax Rate	39%	39%
Equivalent Shares Outstanding (in millions):		
Basic	640 – 645	647 – 652
Diluted	750 – 755	760 – 765
Operating cash flow before changes in assets and liabilities[e][f]	$5,000 – 5,100	***$5,500 – 6,200***
Drilling and completion costs, net of joint venture carries	***($5,500 – 6,000)***	***($5,500 – 6,000)***

Note: please refer to footnotes on following page

a) NYMEX natural gas prices have been updated for actual contract prices through April 2011 and NYMEX oil prices have been updated for actual contract prices through March 2011.
b) Differentials include effects of natural gas liquids.
c) Excludes expenses associated with noncash stock compensation.
d) Does not include gains or losses on interest rate derivatives.
e) 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.
f) Assumes NYMEX prices of $4.00 to $5.00 per mcf and $100.00 per bbl in 2011 and $5.00 to $6.00 per mcf and $100.00 per bbl in 2012.

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) Call options: Chesapeake sells call options in exchange for a premium from the counterparty. 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.
3) Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market prices falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.
4) 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.
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. Since the latter half of 2009 through May 2, 2011, the company has taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to its counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with strike prices above the then current market price. This effectively allowed the company to sell out-year volatility through call options at terms acceptable to Chesapeake in exchange for straight natural gas swaps with strike prices in excess of the market price for natural gas at that time.

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, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Realized gains (losses) are comprised of settled trades related to the production periods being reported. Unrealized gains (losses) are comprised of both temporary fluctuations in the mark-to-market values of nonqualifying trades and settled values of nonqualifying derivatives related to future production periods.

At May 2, 2011, the company has the following open natural gas swaps in place for 2011 and 2012, excluding contracts that will be novated with VPP #9. In addition, the company currently has $593 million of net hedging gains related to closed natural gas contracts and premiums collected on call options for future production periods.

	Open Swaps (Bcf)	Avg. NYMEX Price of Open Swaps	Forecasted Natural Gas Production (Bcf)	Open Swap Positions as a % of Forecasted Natural Gas Production	Total Gains (Losses) from Closed Trades and Collected Call Premiums ($millions)	Total Gains (Losses) from Closed Trades and Collected Call Premiums per mcf of Forecasted Natural Gas Production
Q2 2011	***203***	***$ 5.20***			***$ 276***	
Q3 2011	***195***	***$ 4.92***			***$ 226***	
Q4 2011	***198***	***$ 4.97***			***$ 185***	
Total 2011	***596***	***$ 5.03***	***675***	***88%***	***$ 687***	***$ 1.02***
Total 2012	***188***	***$ 6.17***	980	***19%***	$ (9)	$ (0.01)
Total 2013					$ 11	
Total 2014					$ (38)	
Total 2015					$ (43)	
Total 2016 – 2020					$ (15)	

The company currently has the following natural gas written call options in place for 2011 through 2020:

	Call Options (Bcf)	Avg. NYMEX Strike Price	Forecasted Natural Gas Production (Bcf)	Call Options as a % of Forecasted Natural Gas Production
Total 2011	—	—	***675***	0%
Total 2012	161	$ 6.54	980	16%
Total 2013	436	$ 6.44		
Total 2014	330	$ 6.43		
Total 2015	226	$ 6.31		
Total 2016 – 2020	324	$ 8.13		

The company has the following natural gas basis protection swaps in place for 2011 through 2022:

	Non-Appalachia		Appalachia	
	Volume (Bcf)	Avg. NYMEX less	Volume (Bcf)	Avg. NYMEX plus
2011	45	$ 0.82	49	$ 0.14
2012	51	$ 0.78	—	$ —
2013 - 2022	29	$ 0.69	—	$ —
Totals	125	$ 0.77	49	$ 0.14

At May 2, 2011, the company has the following open crude oil swaps in place for 2011 and 2012, excluding contracts that will be novated with VPP #9. In addition, the company has $4 million of net hedging losses related to closed crude oil contracts and premiums collected on call options for future production periods.

	Open Swaps (mbbls)	Avg. NYMEX Price of Open Swaps	Forecasted Oil Production (mbbls)	Open Swap Positions as a % of Forecasted Oil Production	Total Gains (Losses) from Closed Trades and Collected Call Premiums ($millions)	Total Gains from Closed Trades and Collected Call Premiums per bbl of Forecasted Oil Production
Q2 2011	***1638***	***$ 102.96***	—	—	$ 13	
Q3 2011	***1656***	***$ 102.96***	—	—	$ 13	
Q4 2011	***1656***	***$ 102.96***	—	—	$ 13	
Total 2011[(a)]	***4,950***	***$ 102.96***	***28,000***	***18%***	***$ 39***	***$ 1.37***
Total 2012[(a)]	***5,490***	***$ 104.78***	54,000	***10%***	$ 51	***$ 0.94***
Total 2013					$ 6	
Total 2014					$ (198)	
Total 2015					$ 94	
Total 2016 – 2020					$ 4	

(a) Certain hedging contracts include knockout swaps with provisions limiting the counterparty's exposure below prices of $60.00 covering 1 mmbbls in each of 2011 and 2012.

The company currently has the following crude oil written call options in place for 2011 through 2017:

	Call Options (mbbls)	Avg. NYMEX Strike Price	Forecasted Oil Production (mbbls)	Call Options as a % of Forecasted Oil Production
Q2 2011	1,820	$ ***85.44***		
Q3 2011	1,840	$ ***87.50***		
Q4 2011	1,840	$ ***87.50***		
Total 2011	***5,500***	$ ***86.82***	***28,000***	***20%***
Total 2012	22,139	$ 87.93	54,000	41%
Total 2013	14,564	$ 87.20		
Total 2014	8,707	$ 87.72		
Total 2015	***8,233***	***$ 87.27***		
Total 2016 – 2017	***11,423***	***$ 85.75***		