NEWS RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2008 Third Quarter

Company Reports 2008 Third Quarter Net Income to Common Shareholders of $3.282 Billion, or $5.61 per Fully Diluted Common Share; Adjusted Net Income Available to Common Shareholders Is $486 Million, or $0.85 per Fully Diluted Common Share, an Increase of 47% Over 2007 Third Quarter Company Reports 2008 Third Quarter Production of 2.3 Bcfe per Day, an Increase of 15% Over 2007 Third Quarter Production Proved Reserves Reach 12.1 Tcfe and Increase 11% Year-to-Date on 1.2 Tcfe of Net Additions; Company Delivers First Three Quarters of 2008 Reserve Replacement Rate of 290% and a Drilling and Net Acquisition Cost of $1.35 per Mcfe

OKLAHOMA CITY--(BUSINESS WIRE)--Oct. 30, 2008--Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2008 third quarter. For the quarter, Chesapeake reported net income to common shareholders of $3.282 billion ($5.61 per fully diluted common share), operating cash flow of $1.400 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $5.963 billion (defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $7.491 billion and production of 214 billion cubic feet of natural gas equivalent (bcfe). The results above include the following items that are typically not included in published estimates of the company's financial results by certain securities analysts:

-- an unrealized noncash after-tax mark-to-market (MTM) gain of $2.846 billion from future period natural gas, oil and interest rate hedges primarily resulting from lower natural gas and oil prices as of September 30, 2008 compared to June 30, 2008;

-- an after-tax loss of $19.0 million on the early redemption of the company's $300 million 7.75% Senior Notes due 2015;

-- an after-tax consent fee of $6.3 million paid to amend certain provisions contained in five of the company's senior note indentures; and

-- a reduction of net income available to common shareholders of $24.5 million resulting from exchanges of the company's preferred stock for common stock that reduced future preferred stock dividend payment requirements.

Including the items noted above, Chesapeake reported adjusted net income to common shareholders during the quarter of $486 million ($0.85 per fully diluted common share) and adjusted ebitda of $1.386 billion, increases of 47% and 16%, respectively, over the 2007 third quarter. 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 14 - 17 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2008 third quarter and compares them to results during the 2008 second quarter and the 2007 third quarter.

	Three Months Ended:		
	9/30/08	6/30/08	9/30/07
Average daily production (in mmcfe)	2,321	2,328	2,026
Natural gas as % of total production	92	92	91
Natural gas production (in bcf)	196.7	195.0	170.3
Average realized natural gas price ($/mcf) (a)	8.02	8.18	7.41
Oil production (in mbbls)	2,810	2,816	2,680

Average realized oil price ($/bbl) (a)	75.74	76.96	69.25
Natural gas equivalent production (in bcfe)	213.5	211.9	186.4
Natural gas equivalent realized price ($/mcfe) (a)	8.38	8.55	7.76
Natural gas and oil marketing income ($/mcfe)	.11	.12	.10
Service operations income ($/mcfe)	.04	.04	.06
Production expenses ($/mcfe)	(1.12)	(1.03)	(.89)
Production taxes ($/mcfe)	(.41)	(.41)	(.30)
General and administrative costs ($/mcfe) (b)	(.38)	(.38)	(.23)
Stock-based compensation ($/mcfe)	(.12)	(.10)	(.10)
DD&A of natural gas and oil properties ($/mcfe)	(2.25)	(2.47)	(2.57)
D&A of other assets ($/mcfe)	(.23)	(.19)	(.24)
Interest expense ($/mcfe) (a)	(.26)	(.36)	(.52)
Operating cash flow ($ in millions) (c)	1,400	1,443	1,085
Operating cash flow ($/mcfe)	6.56	6.81	5.82
Adjusted ebitda ($ in millions) (d)	1,386	1,435	1,195
Adjusted ebitda ($/mcfe)	6.49	6.77	6.41
Net income (loss) to common shareholders ($ in millions)	3,282	(1,649)	346
Earnings (loss) per share - assuming dilution ($)	5.61	(3.17)	.72
Adjusted net income to common shareholders ($ in millions) (e)	486	479	330
Adjusted earnings per share - assuming dilution ($)	.85	.89	.69

(a) includes the effects of realized gains or (losses) from hedging, but does not include the effects of unrealized gains or (losses) from hedging

(b) excludes expenses associated with noncash stock-based compensation

(c) defined as cash flow provided by operating activities before changes in assets and liabilities

(d) 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 16

(e) defined as net income (loss) available to common shareholders, as adjusted to remove the effects of certain items detailed on page 16

2008 Third Quarter Average Daily Production Increases 15% over 2007 Third Quarter Production

Daily production for the 2008 third quarter averaged 2.321 bcfe, a decrease of 7 mmcfe, or 0.3%, over the 2.328 bcfe produced per day in the 2008 second quarter and an increase of 295 mmcfe, or 15%, over the 2.026 bcfe produced per day in the 2007 third quarter. Adjusted for the company's year-end 2007, second quarter 2008 and third quarter 2008 VPP sales of 55, 47 and 47 mmcfe per day, respectively, and the company's sale of Woodford Shale and Fayetteville Shale properties of 47 and 45 mmcfe per day, respectively, Chesapeake's sequential and year-over-year production growth rates were 3% and 23%, respectively. In addition, during the quarter hurricane-related production curtailments totaled approximately 1.6 bcfe while voluntary production cutbacks due to low wellhead natural gas prices totaled approximately 0.6 bcfe.

Chesapeake's average daily production for the 2008 third quarter consisted of 2.138 billion cubic feet of natural gas (bcf) and 30,543 barrels of oil and natural gas liquids (bbls). The company's 2008 third quarter production of 213.5 bcfe was comprised of 196.7 bcf (92% on a natural gas equivalent basis) and 2.81 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis).

Natural Gas and Oil Proved Reserves Reach 12.1 Tcfe on 1.2 Tcfe of Net Additions; During the First Three Quarters of 2008, Company Delivers a Reserve Replacement Rate of 290% and a Drilling and Net Acquisition Cost of $1.35 per Mcfe

Chesapeake began 2008 with estimated proved reserves of 10.879 trillion cubic feet of natural gas equivalent (tcfe) and ended the third quarter with 12.075 tcfe, an increase of 1.196 tcfe, or 11%. During the first three quarters of 2008, Chesapeake replaced 630 bcfe of production with an estimated 1.826 tcfe of new proved reserves for a reserve replacement rate of 290%. Reserve replacement through the drillbit was 2.286 tcfe, or 363% of production. This includes 1,128 bcfe of positive performance revisions (including 987 bcfe related to infill drilling and increased density locations) and 13 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and September 30, 2008. Acquisitions of proved reserves completed during the first three quarters of 2008 were 165 bcfe at a cost of $357 million, or $2.16 per mcfe, while sales of proved reserves during the first three quarters of 2008 totaled 638 bcfe for proceeds of $2.335 billion, or $3.66 per mcfe. Sales of undeveloped leasehold during the first three quarters of 2008 generated proceeds of $3.6 billion compared to a cost basis of approximately $750 million for the leasehold sold.

Chesapeake's total drilling and net acquisition costs for the first three quarters of 2008 were $1.35 per mcfe. This calculation excludes costs of $3.3 billion for the acquisition of unproved properties and leasehold (net of sales), $289 million for capitalized interest on unproved properties, $234 million for seismic, and $19 million relating to tax basis step-up and asset retirement obligations, as well as positive revisions of proved reserves from higher natural gas and oil prices. Excluding these items and acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during the first three quarters of 2008 were $1.94 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 12 of this release.

During the first three quarters of 2008, Chesapeake continued the industry's most active drilling program and drilled 1,435 gross operated wells (1,193 net with an average working interest of 83.1%) and participated in another 1,439 gross wells operated by other companies (195 net with an average working interest of 13.6%). The company's drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during the first three quarters of 2008, Chesapeake invested $3.852 billion in operated wells (using an average of 148 operated rigs) and $576 million in non-operated wells (using an average of 118 non-operated rigs) for total drilling, completing and equipping costs of $4.428 billion.

As of September 30, 2008, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10), were $24.4 billion using field differential adjusted prices of $6.48 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $7.12 per mcf) and $96.66 per bbl (based on a NYMEX quarter-end price of $100.66 per bbl). Chesapeake's PV-10 changes by approximately $420 million for every $0.10 per mcf change in natural gas prices and approximately $60 million for every $1.00 per bbl change in oil prices. Chesapeake's enterprise value (market equity value plus long-term debt less working capital excluding current portion of derivative assets and liabilities) as of October 29, 2008 was approximately $27 billion.

By comparison, the December 31, 2007 PV-10 of the company's proved reserves was $20.6 billion ($15.0 billion applying the SFAS 69 standardized measure) using field differential adjusted prices of $6.19 per mcf (based on a NYMEX year-end price of $6.80 per mcf) and $90.58 per bbl (based on a NYMEX year-end price of $96.00 per bbl). The September 30, 2007 PV-10 of the company's proved reserves was $19.4 billion using field differential adjusted prices of $5.85 per mcf (based on a NYMEX quarter-end price of $6.38 per mcf) and $76.76 per bbl (based on a NYMEX quarter-end price of $81.56 per bbl).

The company calculates the standardized measure of future net cash flows in accordance with SFAS 69 only at year end because applicable income tax information on properties, including recently acquired natural gas and oil interests, is not readily available at other times during the year. As a result, the company is not able to reconcile the interim period-end 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.

In addition to the PV-10 value of its proved reserves and the very significant value of its undeveloped leasehold, particularly in the Haynesville, Marcellus, Barnett and Fayetteville shale plays, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other non-current assets) was $4.9 billion as of September 30, 2008, $3.1 billion as of December 31, 2007 and $2.9 billion as of September 30, 2007.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2008 third quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.02 per mcf and $75.74 per bbl, for a realized natural gas equivalent price of $8.38 per mcfe. Realized gains and losses from natural gas and oil hedging activities during the 2008 third quarter generated a $0.71 loss per mcf and a $37.79 loss per bbl for a 2008 third quarter realized hedging loss of $246 million, or $1.15 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2008 third quarter were a negative $1.52 per mcf and a negative $4.46 per bbl.

By comparison, average prices realized during the 2007 third quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $7.41 per mcf and $69.25 per bbl, for a realized natural gas equivalent price of $7.76 per mcfe. Realized gains from natural gas and oil hedging activities during the 2007 third quarter generated a $1.70 gain per mcf and a $1.51 loss per bbl for a 2007 third quarter realized hedging gain of $286 million, or $1.53 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2007 third quarter were a negative $0.45 per mcf and a negative $4.62 per bbl.

The following tables summarize Chesapeake's open hedge position through swaps and collars as of October 30, 2008. 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 October 30, 2008

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2008 Q4	62%	9.15	43%	78.09
2009 Total	38%	9.33	48%	81.19
2010 Total	40%	9.58	37%	90.25

Open Natural Gas Collar Positions as of October 30, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q4	14%	7.75	9.32
2009 Total	30%	7.21	9.27
2010 Total	2%	7.71	11.46

Certain open natural gas swap positions include knockout swaps with knockout provisions at $6.50 per mcf covering 9 bcf in the 2008 fourth quarter, and prices ranging from $5.65 to $7.25 per mcf covering 150 bcf in 2009 and $5.45 to $7.40 per mcf covering 321 bcf in 2010. Certain open natural gas collar positions include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 per mcf covering 105 bcf in 2009 and at $6.00 per mcf covering 4 bcf in 2010. Also, certain open oil swap positions include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45 to $60 per bbl covering 1 mmbbls in the 2008 fourth quarter, from $50 to $60 per bbl covering 6 mmbbls in 2009 and $60 per bbl covering 5 mmbbls in 2010. As of October 24, 2008, Chesapeake's natural gas and oil hedging positions with a diversified group of 19 different counterparties had a positive mark-to-market (MTM) value of approximately $1.0 billion.

The company's updated forecasts for 2008 through 2010 are attached to this release in an Outlook dated October 30, 2008, labeled as Schedule "A," which begins on page 18. This Outlook has been changed from the Outlook dated October 14, 2008 (attached as Schedule "B," which begins on page 23) to reflect various updated information.

Company Continues to Improve Balance Sheet and Liquidity

As a result of strong earnings growth and favorable changes in the MTM value of the company's open hedging positions during the 2008 third quarter, Chesapeake's net debt to book capitalization ratio decreased from 57% at June 30, 2008 to 43% at September 30, 2008. The company's goal is to end 2008 with cash and cash equivalents on hand or bank credit availability of approximately $3.0 billion and to generate at least $1.0 billion of excess cash in each of 2009 and 2010. The company's revolving credit facility matures in November 2012 and the first maturity of its senior unsecured notes is in July 2013.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report our financial and operational results for the 2008 third quarter. During the quarter, we earned almost $3.3 billion, improved our balance sheet and liquidity and closed approximately $7.5 billion of asset monetization transactions. Those transactions included selling a VPP for approximately $600 million in cash, selling 20% of our Haynesville Shale properties for $3.3 billion in cash and drilling carries, selling 25% of our Fayetteville Shale properties for $1.9 billion in cash and drilling carries and selling 100% of our remaining Woodford Shale properties for $1.7 billion in cash. Furthermore we are progressing on additional asset monetizations for the 2008 fourth quarter and we look forward to disclosing the details of these transactions later this quarter.

"Although financial market volatility remains high, Chesapeake is very well-positioned to continue growing and creating value in the 2008 fourth quarter and in 2009 and 2010. Our commodity hedges, our Haynesville and Fayetteville Shale drilling cost carries, our progress in the Marcellus Shale and our balance sheet, which has $2.0 billion in cash on it and requires no debt payments for four years, should enable Chesapeake to prosper during these difficult economic times. I am very excited to see the company continue realizing its full potential through the ongoing execution of our successful strategy and the full development of our top-tier properties."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, October 31, 2008, at 9:00 a.m. EDT. The telephone number to access the conference call is 913-312-1437 or toll-free 888-240-9345. The passcode for the call is 7433119. 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 2:00 p.m. EDT on October 31, 2008 through midnight EST on Friday, November 14, 2008. The number to access the conference call replay is 719-457-0820 or toll-free 888-203-1112. The passcode for the replay is 7433119. 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 and selecting the "News & Events" section. The webcast of the conference call will be available on our 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 estimates of natural gas and oil reserves, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data and planned asset sales, as well as statements concerning anticipated 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 in "Risk Factors" in the Prospectus Supplement we filed with the U.S. Securities and Exchange Commission on July 10, 2008. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; our ability to compete effectively against strong independent natural gas and oil companies and majors; 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; uncertainties in evaluating natural gas and oil reserves of acquired properties and associated potential liabilities; our ability to effectively consolidate and integrate acquired properties and operations; unsuccessful exploration and development drilling; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; lower prices realized on natural gas and oil sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; production interruptions that could adversely affect our cash flow; and 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 the largest producer of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on exploratory and developmental drilling and corporate and property acquisitions in the Fort Worth Barnett Shale, Haynesville Shale, Fayetteville Shale, Anadarko Basin, Arkoma Basin, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. Further information is available at www.chk.com.

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

THREE MONTHS ENDED:	September 30, 2008 $	$/mcfe	September 30, 2007 $	$/mcfe
REVENUES:				
Natural gas and oil sales	6,408	30.01	1,492	8.00
Natural gas and oil marketing sales	1,038	4.86	501	2.69
Service operations revenue	45	0.21	34	0.18
Total Revenues	7,491	35.08	2,027	10.87
OPERATING COSTS:				
Production expenses	239	1.12	165	0.89
Production taxes	87	0.41	56	0.30
General and administrative expenses	108	0.50	62	0.33
Natural gas and oil marketing expenses	1,014	4.75	483	2.59
Service operations expense	37	0.17	23	0.12
Natural gas and oil depreciation, depletion and amortization	480	2.25	479	2.57
Depreciation and amortization of other assets	48	0.23	44	0.24
Total Operating Costs	2,013	9.43	1,312	7.04
INCOME FROM OPERATIONS	5,478	25.65	715	3.83
OTHER INCOME (EXPENSE):				
Interest and other income	(2)	(0.01)	1	0.01
Interest expense	(48)	(0.22)	(116)	(0.62)
Loss on repurchase of Chesapeake debt	(31)	(0.14)	--	--
Consent solicitation fees	(10)	(0.05)	--	--
Total Other Income (Expense)	(91)	(0.42)	(115)	(0.61)
INCOME BEFORE INCOME TAXES	5,387	25.23	600	3.22
Income Tax Expense:				
Current	193	0.90	9	0.05
Deferred	1,881	8.81	219	1.17
Total Income Tax Expense	2,074	9.71	228	1.22
NET INCOME	3,313	15.52	372	2.00
Preferred stock dividends	(6)	(0.03)	(26)	(0.14)
Loss on conversion/exchange of preferred stock	(25)	(0.12)	--	--
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	3,282	15.37	346	1.86

EARNINGS PER COMMON SHARE:

Basic	$ 5.93	$ 0.76
Assuming dilution	$ 5.61	$ 0.72

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

Basic	554	454
Assuming dilution	588	517

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

NINE MONTHS ENDED:	September 30, 2008 $	$/mcfe	September 30, 2007 $	$/mcfe
REVENUES:				
Natural gas and oil sales	5,587	8.87	4,164	8.16
Natural gas and oil marketing sales	2,934	4.66	1,446	2.84
Service operations revenue	127	0.20	101	0.20
Total Revenues	8,648	13.73	5,711	11.20
OPERATING COSTS:				
Production expenses	658	1.04	461	0.90
Production taxes	250	0.40	151	0.30
General and administrative expenses	288	0.46	168	0.33
Natural gas and oil marketing expenses	2,864	4.55	1,394	2.73
Service operations expense	104	0.16	67	0.13
Natural gas and oil depreciation, depletion and amortization	1,518	2.41	1,314	2.58
Depreciation and amortization of other assets	125	0.20	120	0.24
Total Operating Costs	5,807	9.22	3,675	7.21
INCOME FROM OPERATIONS	2,841	4.51	2,036	3.99
OTHER INCOME (EXPENSE):				
Interest and other income	(13)	(0.02)	12	0.02
Interest expense	(212)	(0.33)	(279)	(0.54)
Gain on sale of investment	--	--	83	0.16
Loss on repurchase of Chesapeake debt	(31)	(0.05)	--	--
Consent solicitation fees	(10)	(0.02)	--	--
Total Other Income				

(Expense)	(266)	(0.42)	(184)	(0.36)
INCOME BEFORE INCOME TAXES	2,575	4.09	1,852	3.63
Income Tax Expense:				
Current	196	0.31	19	0.04
Deferred	795	1.26	685	1.34
Total Income Tax Expense	991	1.57	704	1.38
NET INCOME	1,584	2.52	1,148	2.25
Preferred stock dividends	(27)	(0.04)	(77)	(0.15)
Loss on conversion/exchange of preferred stock	(67)	(0.11)	--	--
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	1,490	2.37	1,071	2.10

EARNINGS PER COMMON SHARE:

Basic	$ 2.85	$ 2.37
Assuming dilution	$ 2.73	$ 2.23

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

Basic	523	452
Assuming dilution	557	516

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

	September 30, 2008	December 31, 2007
Cash	$ 1,964	$ 1
Other current assets	2,147	1,395
Total Current Assets	4,111	1,396
Property and equipment (net)	34,845	28,337
Other assets	1,062	1,001
Total Assets	$ 40,018	$ 30,734
Current liabilities	$ 3,601	$ 2,760
Long-term debt, net	14,345	10,950
Asset retirement obligation	260	236
Other long-term liabilities	715	692
Deferred tax liability	4,690	3,966

Total Liabilities	23,611	18,604
Stockholders' Equity	16,407	12,130
Total Liabilities & Stockholders' Equity	$ 40,018	$ 30,734
Common Shares Outstanding (in millions)	581	511

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

	September 30, 2008	% of Total Book Capitalization	June 30, 2008	% of Total Book Capitalization
Total debt, net cash	$ 12,381	43%	$ 13,703	57%
Stockholders' equity	16,407	57%	10,276	43%
Total	$ 28,788	100%	$ 23,979	100%

	December 31, 2007	% of Total Book Capitalization
Total debt, net cash	$ 10,949	47%
Stockholders' equity	12,130	53%
Total	$ 23,079	100%

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2008 ADDITIONS TO NATURAL GAS AND OIL PROPERTIES
($ in millions, except per-unit data)
(unaudited)

	Cost	Reserves (in bcfe)	$/mcfe
Exploration and development costs	$ 4,428	2,286(a)	1.94
Acquisition of proved properties	357	165	2.16
Sale of proved properties	(2,335)	(638)	3.66
Drilling and net acquisition cost	2,450	1,813	1.35
Revisions - price	--	13	--
Acquisition of unproved properties and leasehold	6,931	--	--
Sale of unproved properties and leasehold	(3,587)	--	--
Net leasehold and unproved property acquisition	3,344	--	--

Capitalized interest on leasehold and unproved property	289	--	--
Geological and geophysical costs	234	--	--
Geological, geophysical and capitalized interest	523	--	--
Subtotal	6,317	1,826	3.46
Tax basis step-up	13	--	--
Asset retirement obligation and other	6	--	--
Total	$ 6,336	1,826	3.47

(a) Includes 1,128 bcfe of positive performance revisions (987 bcfe relating to infill drilling and increased density locations and 141 bcfe of other performance related revisions) and excludes positive revisions of 13 bcfe resulting from natural gas and oil price increases between December 31, 2007 and September 30, 2008.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
NINE MONTHS ENDED SEPTEMBER 30, 2008
(unaudited)

	Bcfe
Beginning balance, 01/01/08	10,879
Production	(630)
Acquisitions	165
Divestitures	(638)
Revisions - performance	1,128
Revisions - price	13
Extensions and discoveries	1,158
Ending balance, 09/30/08	12,075
Reserve replacement	1,826
Reserve replacement ratio (a)	290%

(a) The company uses the reserve replacement ratio as an indicator of the company's ability to replenish annual production volumes and grow its reserves. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. The ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not embed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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

	THREE MONTHS ENDED September 30,		NINE MONTHS ENDED September 30,	
	2008	2007	2008	2007
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 1,717	$ 971	$ 5,046	$ 2,918
Natural gas derivatives - realized gains (losses)	(140)	290	(174)	890
Natural gas derivatives - unrealized gains (losses)	3,854	73	325	(58)

Total Natural Gas Sales	5,431	1,334	5,197	3,750
Oil sales	319	190	915	443
Oil derivatives - realized gains (losses)	(106)	(4)	(280)	26
Oil derivatives - unrealized gains (losses)	764	(28)	(245)	(55)
Total Oil Sales	977	158	390	414
Total Natural Gas and Oil Sales	$ 6,408	$ 1,492	$ 5,587	$ 4,164
Average Sales Price - excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 8.73	$ 5.71	$ 8.71	$ 6.25
Oil ($ per bbl)	$113.53	$ 70.76	$109.28	$ 61.91
Natural gas equivalent ($ per mcfe)	$ 9.54	$ 6.23	$ 9.47	$ 6.59
Average Sales Price - excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 8.02	$ 7.41	$ 8.41	$ 8.15
Oil ($ per bbl)	$ 75.74	$ 69.25	$ 75.82	$ 65.55
Natural gas equivalent ($ per mcfe)	$ 8.38	$ 7.76	$ 8.75	$ 8.39
Interest Expense ($ in millions):				
Interest	$ 51	$ 98	$ 220	$ 266
Derivatives - realized (gains) losses	5	(1)	1	--
Derivatives - unrealized (gains) losses	(8)	19	(9)	13
Total Interest Expense	$ 48	$ 116	$ 212	279

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

THREE MONTHS ENDED:	September 30, 2008	September 30, 2007
Beginning cash	$ 1	$ 4
Cash provided by operating activities	1,550	1,267
Cash (used in) investing activities	(1,872)	(2,485)
Cash provided by financing activities	2,285	1,216
Ending cash	1,964	2

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
Beginning cash	$ 1	$ 3
Cash provided by operating activities	4,305	3,389
Cash (used in) investing activities	(8,201)	(6,488)
Cash provided by financing activities	5,859	3,098
Ending cash	1,964	2

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

THREE MONTHS ENDED:	September 30, 2008	June 30, 2008	September 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,550	$ 1,256	$ 1,267
Adjustments:			
Changes in assets and liabilities	(150)	187	(182)
OPERATING CASH FLOW(1)	$ 1,400	$ 1,443	$ 1,085

(1) 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.

THREE MONTHS ENDED:	September 30, 2008	June 30, 2008	September 30, 2007
NET INCOME (LOSS)	$ 3,313	$ (1,597)	$ 372
Income tax expense (benefit)	2,074	(1,000)	228
Interest expense	48	63	116
Depreciation and amortization of other assets	48	40	44
Natural gas and oil depreciation, depletion and amortization	480	523	479
EBITDA(2)	$ 5,963	$ (1,971)	$ 1,239

(2) 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 agreement and is used in the financial covenants in our bank credit agreement 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. Ebitda is reconciled to cash provided by operating activities as follows:

THREE MONTHS ENDED:	September 30, 2008	June 30, 2008	September 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,550	$ 1,256	$ 1,267
Changes in assets and liabilities	(150)	187	(182)
Interest expense	48	63	116
Unrealized gains (losses) on natural gas and oil derivatives	4,618	(3,404)	45
Other non-cash items	(103)	(73)	(7)
EBITDA	$ 5,963	$ (1,971)	$ 1,239

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

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 4,305	$ 3,389
Adjustments:		
Changes in assets and liabilities	49	(104)
OPERATING CASH FLOW(1)	$ 4,354	$ 3,285

(1) 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.

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
NET INCOME	$ 1,584	$ 1,148
Income tax expense (benefit)	991	704
Interest expense	212	279

Depreciation and amortization of other assets	125	120
Natural gas and oil depreciation, depletion and amortization	1,518	1,314
EBITDA(2)	$ 4,430	$ 3,565

(2) 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 agreement and is used in the financial covenants in our bank credit agreement 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. Ebitda is reconciled to cash provided by operating activities as follows:

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 4,305	$ 3,389
Changes in assets and liabilities	49	(104)
Interest expense	212	279
Unrealized gains (losses) on natural gas and oil derivatives	80	(113)
Other noncash items	(216)	114
EBITDA	$ 4,430	$ 3,565

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

THREE MONTHS ENDED:	September 30, 2008	June 30, 2008	September 30, 2007
Net income (loss) available to common shareholders	$ 3,282	$ (1,649)	$ 346
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	(2,846)	2,085	(16)
Loss on repurchase of Chesapeake debt, net of tax	19	--	--
Consent fees on senior notes, net of tax	6	--	--
Loss on conversion/exchange of preferred stock	25	43	--
Adjusted net income available to common shareholders(1)	486	479	330

Preferred stock dividends	6	9	26
Interest on 2.75% contingent convertible notes, net of tax	3	3	--
Interest on 2.50% contingent convertible notes, net of tax	7	--	--
Total adjusted net income	$ 502	$ 491	$ 356
Weighted average fully diluted shares outstanding(2)	589	553	517
Adjusted earnings per share assuming dilution(1)	$ 0.85	$ 0.89	$ 0.69

(1) Adjusted net income available to common 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:

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

(b) Adjusted net income available to common is more comparable to earnings estimates provided by securities analysts.

(c) 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.

(2) 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 EBITDA
($ in millions)
(unaudited)

THREE MONTHS ENDED:	September 30, 2008	June 30, 2008	September 30, 2007
EBITDA	$ 5,963	$ (1,971)	$ 1,239
Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	(4,618)	3,406	(45)
Loss on repurchase of Chesapeake debt	31	--	--
Consent fees on senior notes	10	--	--
Adjusted ebitda(1)	$ 1,386	$ 1,435	$ 1,194

(1) 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:

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

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

(c) 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 SHAREHOLDERS
($ in millions, except per-share data)
(unaudited)

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
Net income available to common shareholders	$ 1,490	$ 1,071
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	(55)	78
Gain on sale of investment, net of cash	--	(51)
Loss on repurchase of Chesapeake debt, net of tax	19	--
Consent fees on senior notes, net of tax	6	--
Loss on conversion/exchange of preferred stock	67	--
Adjusted net income available to common shareholders(1)	1,527	1,098
Preferred stock dividends	27	77
Interest on 2.75% contingent convertible notes, net of tax	5	--
Interest on 2.50% contingent convertible notes, net of tax	7	--
Total adjusted net income	$ 1,566	$ 1,175
Weighted average fully diluted shares outstanding(2)	564	516
Adjusted earnings per share assuming dilution(1)	$ 2.78	$ 2.28

(1) Adjusted net income available to common 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:

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

(b) Adjusted net income available to common is more comparable to earnings estimates provided by securities analysts.

(c) 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.

(2) 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 EBITDA
($ in millions)

(unaudited)

NINE MONTHS ENDED:	September 30, 2008	September 30, 2007
EBITDA	$ 4,430	$ 3,565
Adjustments, before tax:		
Unrealized (gains) losses on natural gas and oil derivatives	(80)	113
Gain on sale of investment	--	(83)
Loss on repurchase of Chesapeake debt	31	--
Consent fees on senior notes	10	--
Adjusted ebitda(1)	$ 4,391	$ 3,595

(1) 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:

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

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

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

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF OCTOBER 30, 2008

Quarter Ending December 31, 2008 and Years Ending December 31, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of October 30, 2008, we are using the following key assumptions in our projections for the fourth quarter of 2008 and the full years 2009 and 2010.

The primary changes from our October 14, 2008 Outlook are in italicized bold and are explained as follows:

1) Natural gas production assumption for the quarter ending 12/31/08 has been reduced to reflect anticipated voluntary curtailments due to low wellhead price realizations;

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

3) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been reduced for the quarter ending 12/31/08; and

4) Certain cost and cash income tax assumptions have been updated.

	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production(a)			
Natural gas - bcf	188 - 192	893 - 913	1,032 - 1,072
Oil - mbbls	2,825	12,000	13,000
Natural gas equivalent - bcfe	205 - 209	965 - 985	1,110 -1,150
Daily natural gas equivalent midpoint - mmcfe	2,250	2,670	3,095
Year-over-year production increase	1.4%	16.8%	15.9%

NYMEX Prices (b) (for calculation of realized hedging effects only):			
Natural gas - $/mcf	$7.00	$8.00	$8.00
Oil - $/bbl	$60.00	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	$1.96	$0.70	$0.82
Oil - $/bbl	$5.48	$1.32	$4.79
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	10 - 14%	10 - 14%	10 - 14%
Oil - $/bbl	5 - 7%	5 - 7%	5 - 7%
Operating Costs per Mcfe of Projected Production:			
Production expense	$1.00 - 1.15	$1.10 - 1.20	$1.15 - 1.25
Production taxes (about 5% of O&G revenues) (c)	$0.30 - 0.35	$0.35 - 0.40	$0.35 - 0.40
General and administrative(d)	$0.33 - 0.37	$0.33 - 0.37	$0.33 - 0.37
Stock-based compensation (non-cash)	$0.10 - 0.13	$0.10 - 0.12	$0.10 - 0.12
DD&A of natural gas and oil assets	$2.25 - 2.30	$2.20 - 2.30	$2.15 - 2.25
Depreciation of other assets	$0.20 - 0.25	$0.20 - 0.24	$0.20 - 0.24
Interest expense(e)	$0.30 - 0.35	$0.40 - 0.45	$0.35 - 0.40
Other Income per Mcfe:			
Natural gas and oil marketing income	$0.09 - 0.11	$0.09 - 0.11	$0.09 - 0.11
Service operations income	$0.04 - 0.06	$0.04 - 0.06	$0.04 - 0.06
Book Tax Rate	38.5%	38.5%	38.5%
Cash Income Taxes - in millions	$550 - 650	$200 - 300	$200 - 300
Equivalent Shares Outstanding - in millions:			
Basic	560 - 565	565 - 570	575 - 580
Diluted	580 - 585	585 - 590	595 - 600

Cash Flow Projections - in millions	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Net inflows:			
Operating cash flow before changes in assets and liabilities (f)(g)	$1,250 - 1,375	$5,800 - 6,000	$6,250 - 6,750
Leasehold and producing property transactions:			
Sale of leasehold and producing properties (a)	$2,100 - 2,500	$1,250 - 2,000	$1,250 - 2,000
Sale of producing properties via VPP's(a)	$400 - 500	$1,000 - 1,250	$1,000 - 1,250
Acquisition of leasehold			

and producing properties	($750 - $1,000)	($1,250 - $1,750)	($1,000 - $1,500)
Net leasehold and producing property transactions	$1,750 - 2,000	$1,000 - 1,500	$1,250 - 1,750
Debt and equity offerings	-	-	-
Midstream financings	$1,050 - 1,275	$500 - 700	$500 - 700
Proceeds from investments and other	-	$500- 750	$150 - 250
Total Cash Inflows	$4,050 - 4,650	$7,800 - 8,950	$8,150 - 9,450
Net outflows:			
Drilling	$1,200 - 1,300	$4,250 - 4,750	$4,750 - 5,250
Geophysical costs	$75	$225 - 275	$225 - 275
Midstream infrastructure and compression	$300 - 325	$1,000 - 1,200	$900 - 1,000
Other PP&E	$50 - 75	$250 - 300	$250 - 300
Dividends, senior notes redemption, capitalized interest, etc.	$150 - 200	$575 - 600	$575 - 600
Cash income taxes	$550 - 650	$200 - 300	$200 - 300
Total Cash Outflows	$2,325 - 2,625	$6,500 - 7,425	$6,900 - 7,725
Net Cash Change	$1,725 - 2,025	$1,300 -1,525	$1,250 - 1,725

(a) The 2008 fourth quarter production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $450 million in a volumetric production payment (VPP); and 2) producing properties in South Texas and undeveloped leasehold in the Marcellus Shale and other areas for approximately $2.3 billion. The 2009 and 2010 production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $1.1 billion in each year in VPP transactions; and 2) undeveloped leasehold or other producing properties for approximately $1.6 billion in each year.

(b) NYMEX natural gas prices have been updated for actual contract prices through October 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $60.00 per bbl of oil and $6.50 to $7.50 per mcf of natural gas during the 2008 fourth quarter; $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2009; and $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2010.

(d) Excludes expenses associated with noncash stock compensation.

(e) Does not include gains or losses on interest rate derivatives (SFAS 133).

(f) 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.

(g) Assumes NYMEX natural gas prices of $6.50 to $7.50 per mcf and NYMEX oil prices of $60.00 per bbl in the 2008 fourth quarter and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl in 2009 and 2010.

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:

(i) For swap instruments, Chesapeake receives a fixed price and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

(ii) Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which 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 basis protection swaps, which 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.

(iii) For 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 predetermined knockout prices.

(iv) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty

(v) For written call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

(vi) Collars 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 call and the put strike price, no payments are due from either party.

(vii) A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires Chesapeake to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

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. Pursuant to SFAS 133, 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.

Following provisions of SFAS 133, 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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, the company currently has the following open natural gas swaps in place and also has the following gains (losses) from lifted natural gas swaps:

Total

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production	Total Gains (Losses) from Lifted Swaps ($ millions)	Lifted Gain (Loss) per Mcf of Estimated Total Natural Gas Production
Q4 2008	108.2	$9.27	190	57%	$85.2	$0.45
Total 2009(1)	327.7	$9.43	903	36%	($36.7)	($0.04)
Total 2010(1)	422.6	$9.58	1,052	40%	$33.9	$0.03

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below $6.50 covering 9 bcf in 2008 and prices ranging from $5.65 to $7.25 covering 150 bcf in 2009 and $5.45 to $7.40 covering 321 bcf in 2010.

The company currently has the following open natural gas collars in place:

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
Q4 2008	26.6	$7.75	$9.32	190	14%
Total 2009(1)	267.5	$7.21	$9.27	903	30%
Total 2010(1)	25.6	$7.71	$11.46	1,052	2%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 105 bcf in 2009 and at $6.00 covering 4 bcf in 2010.

The company currently has the following natural gas written call options in place:

	Call Options in Bcf's	Avg. NYMEX Call Price	Avg. Premium per mcf	Assuming Natural Gas Production in Bcf's of:	Call Options as a % of Estimated Total Natural Gas Production
Q4 2008	32.2	$10.37	$0.74	190	17%
Total 2009	216.2	$11.40	$0.63	903	24%
Total 2010	231.8	$10.77	$0.72	1,052	22%

The company has the following natural gas basis protection swaps in place:

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(1):	Volume in Bcf's	NYMEX plus(1):
Q4 2008	32.1	$ 0.45	5.8	$ 0.33
2009	77.1	0.35	16.9	0.28
2010	--	--	10.2	0.26
2011	45.1	0.64	12.1	0.25
2012	43.2	0.48	--	--
Totals	197.5	$ 0.46	45.0	$ 0.27

(1) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($76 million as of September 30, 2008). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities," the assumed CNR derivative instruments are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

The following details the CNR derivatives (natural gas swaps) we have assumed:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Open Swap Positions Assuming Natural Gas Production in Bcf's of:	as a % of Estimated Total Natural Gas Production
Q4 2008	9.7	$4.66	$7.84	($3.17)	190	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	903	2%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00.

The company also has the following crude oil swaps in place:

Open	Avg.	Open Swap Positions Assuming Oil	as a % of	Total Gains (Losses) from Lifted	Total Lifted Gain (Loss) per bbl of

	Swaps in mbbls	NYMEX Strike Price	Production in mbbls of:	Estimated Total Oil Production	Swaps ($ millions)	Estimated Total Oil Production
Q4 2008(1)	1,214	$78.09	2,825	43%	($2.3)	($0.81)
Total 2009(1)	5,728	$81.19	12,000	48%	$38.5	$3.21
Total 2010(1)	4,745	$90.25	13,000	37%	--	--

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 982 mbbls in 2008, from $50.00 to $60.00 covering 6,038 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 768 mbbls of production in 2008 at a weighted average price of $85.86 for a weighted average premium of $4.05, 5,110 mbbls of production in 2009 at a weighed average price of $133.93 for a weighted average premium of $3.90 and 5,110 mbbls of production in 2010 at a weighed average price of $140.00 for a weighted average premium of $4.46.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF OCTOBER 14, 2008

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF OCTOBER 30, 2008

Quarter Ending December 31, 2008 and Years Ending December 31, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of October 14, 2008, we are using the following key assumptions in our projections for the fourth quarter of 2008 and the full years 2009 and 2010.

The primary changes from our September 22, 2008 Outlook are in italicized bold and are explained as follows:

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

2) Certain cost assumptions and budgeted capital expenditure assumptions have been updated;

3) Our NYMEX oil price assumption for realized hedging effects and estimating future operating cash flow has been reduced; and

4) Shares outstanding have been updated to remove the effects of certain contingent convertible senior notes that are not presently convertible at the current stock price level.

	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production(a)			
Natural gas - bcf	197 - 201	893 - 913	1,032 - 1,072
Oil - mbbls	2,825	12,000	13,000
Natural gas equivalent - bcfe	214 - 218	965 - 985	1,110 -1,150
Daily natural gas equivalent midpoint - mmcfe	2,350	2,670	3,095
Year-over-year production increase	5.9%	15.6%	15.9%

NYMEX Prices (b) (for calculation of realized hedging effects only):

Natural gas - $/mcf	$7.82	$8.00	$8.00
Oil - $/bbl	$80.00	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	$1.48	$1.04	$0.82
Oil - $/bbl	($2.82)	$2.42	$4.79
Estimated Differentials to NYMEX Prices:			
Natural gas - $/mcf	10 - 14%	10 - 14%	10 - 14%
Oil - $/bbl	5 - 7%	5 - 7%	5 - 7%
Operating Costs per Mcfe of Projected Production:			
Production expense	$1.00 - 1.10	$1.10 - 1.20	$1.15 - 1.25
Production taxes (about 5% of O&G revenues) (c)	$0.35 - 0.40	$0.35 - 0.40	$0.35 - 0.40
General and administrative(d)	$0.33 - 0.37	$0.33 - 0.37	$0.33 - 0.37
Stock-based compensation (non-cash)	$0.10 - 0.12	$0.10 - 0.12	$0.10 - 0.12
DD&A of natural gas and oil assets	$2.30 - 2.35	$2.20 - 2.30	$2.15 - 2.25
Depreciation of other assets	$0.20 - 0.24	$0.20 - 0.24	$0.20 - 0.24
Interest expense(e)	$0.30 - 0.35	$0.40 - 0.45	$0.35 - 0.40
Other Income per Mcfe:			
Natural gas and oil marketing income	$0.09 - 0.11	$0.09 - 0.11	$0.09 - 0.11
Service operations income	$0.04 - 0.06	$0.04 - 0.06	$0.04 - 0.06
Book Tax Rate	38.5%	38.5%	38.5%
Cash Income Taxes - in millions	$350 - 450	$200 - 300	$200 - 300
Equivalent Shares Outstanding - in millions:			
Basic	560 - 565	565 - 570	575 - 580
Diluted	580 - 585	585 - 590	595 - 600

Cash Flow Projections - in millions	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Net inflows:			
Operating cash flow before changes in assets and liabilities (f)(g)	$1,375 - 1,425	$5,800 - 6,000	$6,250 - 6,750
Leasehold and producing property transactions:			
Sale of leasehold and producing properties (a)	$2,100 - 2,500	$1,250 - 2,000	$1,250 - 2,000
Sale of producing properties via VPP's(a)	$400 - 500	$1,000 - 1,250	$1,000 - 1,250
Acquisition of leasehold and producing			

properties	($750 - $1,000)	($1,250 - $1,750)	($1,000 - $1,500)
Net leasehold and producing property transactions	$1,750 - 2,000	$1,000 - 1,500	$1,250 - 1,750
Debt and equity offerings	-	-	-
Midstream financings	$1,050 - 1,275	$500 - 700	$500 - 700
Proceeds from investments and other	-	$500 - 750	$150 - 250
Total Cash Inflows	$4,175 - 4,700	$7,800 - 8,950	$8,150 - 9,450
Net outflows:			
Drilling	$1,200 - 1,300	$4,250 - 4,750	$4,750 - 5,250
Geophysical costs	$75	$225 - 275	$225 - 275
Midstream infrastructure and compression	$300 - 325	$1,000 - 1,200	$900 - 1,000
Other PP&E	$50 - 75	$250 - 300	$250 - 300
Dividends, senior notes redemption, capitalized interest, etc.	$150 - 200	$575 - 600	$575 - 600
Cash income taxes	$350 - 450	$200 - 300	$200 - 300
Total Cash Outflows	$2,125 - 2,425	$6,500 - 7,425	$6,900 - 7,725
Net Cash Change	$2,050 - 2,275	$1,300 -1,525	$1,250 - 1,725

(a) The 2008 fourth quarter production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $450 million in a volumetric production payment (VPP); and 2) producing properties in South Texas and undeveloped leasehold in the Marcellus Shale and other areas for approximately $2.3 billion. The 2009 and 2010 production and cash flow forecasts reflect anticipated sales by the company of: 1) producing properties for approximately $1.1 billion in each year in VPP transactions; and 2) undeveloped leasehold or other producing properties for approximately $1.6 billion in each year.

(b) NYMEX natural gas prices have been updated for actual contract prices through October 2008.

(c) Severance tax per mcfe is based on NYMEX prices of $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during Q4 2008; $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2009; and $80.00 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during 2010.

(d) Excludes expenses associated with noncash stock compensation.

(e) Does not include gains or losses on interest rate derivatives (SFAS 133).

(f) 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.

(g) Assumes NYMEX natural gas of $7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl.

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:

(i) For swap instruments, Chesapeake receives a fixed price and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

(ii) Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which 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 basis protection swaps, which 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.

(iii) For 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 predetermined knockout prices.

(iv) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty

(v) For written call options, Chesapeake receives a premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

(vi) Collars 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 call and the put strike price, no payments are due from either party.

(vii) A three-way collar contract consists of a standard collar contract plus a written put option with a strike price below the floor price of the collar. In addition to the settlement of the collar, the put option requires Chesapeake to make a payment to the counterparty equal to the difference between the put option price and the settlement price if the settlement price for any settlement period is below the put option strike price.

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. Pursuant to SFAS 133, 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.

Following provisions of SFAS 133, 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.

Excluding the swaps assumed in connection with the acquisition of CNR which are described below, the company currently has the following open natural gas swaps in place and also has the following gains (losses) from lifted natural gas swaps:

	Open Swap Positions as a	Total Gains	Total Lifted Gain

	Open Swaps in Bcf's	Avg. NYMEX Strike Price of Open Swaps	Assuming Natural Gas Production in Bcf's of:	% of Estimated Total Natural Gas Production	(Losses) from Lifted Swaps ($ millions)	(Loss) per Mcf of Estimated Total Natural Gas Production
Q4 2008	110.6	$9.30	199	56%	$79.70	$0.40
Total 2009(1)	533.0	$9.46	903	59%	($36.70)	($0.04)
Total 2010(1)	422.6	$9.58	1,052	40%	$33.90	$0.03

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.45 to $6.50 covering 35 bcf in 2008, $5.45 to $7.25 covering 356 bcf in 2009 and $5.45 to $7.40 covering 318 bcf in 2010.

The company currently has the following open natural gas collars in place:

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Assuming Natural Gas Production in Bcf's of:	Open Collars as a % of Estimated Total Natural Gas Production
Q4 2008	26.6	$7.75	$9.32	199	13%
Total 2009(1)	63.9	$8.05	$11.18	903	7%
Total 2010(1)	25.6	$7.71	$11.46	1,052	2%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.50 to $6.00 covering 38 bcf in 2009 and at $6.00 covering 4 bcf in 2010.

The company currently has the following natural gas written call options in place:

	Call Options in Bcf's	Avg. NYMEX Call Price	Avg. Premium per mcf	Assuming Natural Gas Production in Bcf's of:	Call Options as a % of Estimated Total Natural Gas Production
Q4 2008	34.0	$10.39	$0.70	199	17%
Total 2009	225.5	$11.37	$0.61	903	25%
Total 2010	231.8	$10.77	$0.72	1,052	22%

The company has the following natural gas basis protection swaps in place:

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(1):	Volume in Bcf's	NYMEX plus(1):
Q4 2008	32.1	$ 0.45	5.8	$ 0.33
2009	77.1	0.35	16.9	0.28
2010	--	--	10.2	0.26
2011	45.1	0.64	12.1	0.25
2012	43.2	0.48	--	--
Totals	197.5	$ 0.46	45.0	$ 0.27

(1) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($102 million as of June 30, 2008). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our natural gas and oil revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to natural gas and oil revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in natural gas and oil revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities," the assumed CNR derivative instruments are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows.

The following details the CNR derivatives (natural gas swaps) we have assumed:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps (per Mcf)	Avg. Fair Value Upon Acquisition of Open Swaps (per Mcf)	Initial Liability Acquired (per Mcf)	Assuming Natural Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Natural Gas Production
Q4 2008	9.7	$4.66	$7.84	($3.17)	199	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	903	2%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00.

The company also has the following crude oil swaps in place:

	Open Swaps in mbbls	Avg. NYMEX Strike Price	Assuming Oil Production in mbbls of:	Open Swap Positions as a % of Estimated Total Oil Production	Total Losses from Lifted Swaps ($ millions)	Total Lifted Losses per bbl of Estimated Total Oil Production

Q4 2008(1)	1,702	$77.57	2,825	60%	($4.7)	($1.68)
Total 2009(1)	8,364	$82.38	12,000	70%	($0.6)	($0.05)
Total 2010(1)	4,745	$90.25	13,000	37%	--	--

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 1,104 mbbls in 2008, from $52.50 to $60.00 covering 7,848 mbbls in 2009 and $60.00 covering 4,745 mbbls in 2010.

Note: Not shown above are written call options covering 890 mbbls of production in 2008 at a weighted average price of $86.43 for a weighted average premium of $3.63, 3,285 mbbls of production in 2009 at a weighed average price of $122.22 for a weighted average premium of $6.07 and 3,285 mbbls of production in 2010 at a weighed average price of $131.67 for a weighted average premium of $6.94.

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