NEWS RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2008 Full Year and Fourth Quarter

Full Year 2008 Net Income to Common Shareholders Was $623 Million, or $1.14 per Fully Diluted Common Share, on Revenue of $11.6 Billion; Adjusted Net Income Available to Common Shareholders Was $2.0 Billion, or $3.55 per Fully Diluted Common Share, an Increase of 25% Over 2007 Full Year

OKLAHOMA CITY--(BUSINESS WIRE)--Feb. 17, 2009-- Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2008 full year and fourth quarter. For the 2008 full year, Chesapeake reported net income to common shareholders of $623 million ($1.14 per fully diluted common share), operating cash flow of $5.178 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $3.647 billion (defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $11.629 billion and production of 843 billion cubic feet of natural gas equivalent (bcfe). For the 2008 fourth quarter, Chesapeake reported a net loss to common shareholders of $866 million (a loss of $1.51 per fully diluted common share), operating cash flow of $1.015 billion and ebitda of negative $783 million on revenue of $2.981 billion and production of 213 bcfe.

The company's 2008 full year and fourth quarter results above 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, Chesapeake generated adjusted net income to common shareholders for the 2008 full year of $1.954 billion ($3.55 per fully diluted common share) and adjusted ebitda of $5.633 billion, increases of 25% and 12%, respectively, over the 2007 full year. For the 2008 fourth quarter Chesapeake generated adjusted net income to common shareholders of $427 million ($0.73 per fully diluted common share) and adjusted ebitda of $1.242 billion. The excluded items and their effects on 2008 full year and fourth quarter reported results are detailed as follows:

- an unrealized noncash after-tax mark-to-market gain of $434 million for the 2008 full year and $380 million for the 2008 fourth quarter resulting from the company's natural gas, oil and interest rate hedging programs;
- a noncash after-tax impairment charge of $1.73 billion for the 2008 full year and for the 2008 fourth quarter related to the carrying value of natural gas and oil properties and certain midstream assets;
- a noncash after-tax impairment charge of $110 million for the 2008 full year and for the 2008 fourth quarter related to certain investments;
- an after-tax net gain of $144 million for the 2008 full year on exchanges of certain of the company's contingent convertible senior notes for shares of common stock and the early redemption of the company's $300 million 7.75% Senior Notes due 2015 and an after-tax gain of $163 million in the 2008 fourth quarter on exchanges of contingent convertible senior notes;
- an after-tax consent fee of $6 million for the 2008 full year paid to amend certain debt covenants contained in five of the company's senior note indentures; and
- a reduction of net income available to common shareholders of $67 million for the full year 2008 resulting from exchanges of the company's preferred stock for common stock that reduced future preferred stock dividend payment requirements.

The excluded items do not affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 17 – 21 of this release.

Key Operational and Financial Statistics Summarized

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

	Three Months Ended:			Full Year Ended:	
	12/31/08	9/30/08	12/31/07	12/31/08	12/31/07
Average daily production (in mmcfe)	2,316	2,321	2,219	2,303	1,957
Natural gas as % of total production	92	92	92	92	92
Natural gas production (in bcf)	196.0	196.7	187.8	775.4	655.0
Average realized natural gas price ($/mcf) (a)	7.13	8.02	8.11	8.09	8.14
Oil production (in mbbls)	2,848	2,810	2,735	11,220	9,882
Average realized oil price ($/bbl) (a)	54.80	75.74	72.58	70.48	67.50
Natural gas equivalent production (in bcfe)	213.1	213.5	204.2	842.7	714.3
Natural gas equivalent realized price ($/mcfe) (a)	7.29	8.38	8.43	8.38	8.40
Natural gas and oil marketing income ($/mcfe)	.11	.11	.09	.11	.10
Service operations income ($/mcfe)	.04	.04	.04	.04	.06
Production expenses ($/mcfe)	(1.09)	(1.12)	(.88)	(1.05)	(.90)
Production taxes ($/mcfe)	(.16)	(.41)	(.32)	(.34)	(.30)
General and administrative costs ($/mcfe) (b)	(.33)	(.38)	(.29)	(.35)	(.26)

Stock-based compensation ($/mcfe)	(.09)	(.12)	(.08)	(.10)	(.08)
DD&A of natural gas and oil properties ($/mcfe)	(2.12)	(2.25)	(2.55)	(2.34)	(2.37)
D&A of other assets ($/mcfe)	(.24)	(.23)	(.16)	(.21)	(.22)
Interest expense ($/mcfe) (a)	(.04)	(.26)	(.49)	(.27)	(.51)
Operating cash flow ($ in millions) (c)	1,015	1,207	1,335	5,178	4,633
Operating cash flow ($/mcfe)	4.76	5.65	6.54	6.14	6.49
Adjusted ebitda ($ in millions) (d)	1,242	1,386	1,432	5,633	5,028
Adjusted ebitda ($/mcfe)	5.83	6.49	7.01	6.68	7.04
Net income (loss) to common shareholders ($ in millions)	(866)	3,282	158	623	1,229
Earnings (loss) per share – assuming dilution ($)	(1.51)	5.61	.33	1.14	2.62
Adjusted net income to common shareholders ($ in millions) (e)	427	486	466	1,954	1,563
Adjusted earnings per share – assuming dilution ($)	.73	.85	.93	3.55	3.21

(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 pages 19 - 21

(e) defined as net income (loss) available to common shareholders, as adjusted to remove the effects of certain items detailed on pages 19 - 20

2008 Fourth Quarter Average Daily Production Increases 4% over 2007 Fourth Quarter Production; 2008 Full Year Production Increases 18% over 2007 Full Year Production, Setting Record for 19th Consecutive Year

Daily production for the 2008 fourth quarter averaged 2.32 bcfe, flat compared to the 2.32 bcfe produced per day in the 2008 third quarter and an increase of 97 million cubic feet of natural gas equivalent (mmcfe), or 4%, over the 2.22 bcfe produced per day in the 2007 fourth quarter. Adjusted for the company’s year-end 2007, 2008 second quarter and 2008 third quarter volumetric production payment sales of 55, 47 and 47 mmcfe per day, respectively, as well as the company’s sale of Woodford Shale and Fayetteville Shale properties producing 47 and 45 mmcfe per day, respectively, Chesapeake’s sequential and year-over-year production growth rates were 2% and 14%, respectively. In addition, voluntary production curtailments due to low wellhead natural gas prices totaled approximately 65 mmcfe per day during the 2008 fourth quarter.

Chesapeake’s average daily production for the 2008 fourth quarter consisted of 2.13 billion cubic feet of natural gas (bcf) and 30,956 barrels of oil and natural gas liquids (bbls). The company’s 2008 fourth quarter production of 213 bcfe was comprised of 196 bcf (92% on a natural gas equivalent basis) and 2.8 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis).

Chesapeake’s 2008 full year production of 843 bcfe was comprised of 775 bcf (92% on a natural gas equivalent basis) and 11.2 mmbbls (8% on a natural gas equivalent basis). Chesapeake’s average daily production for the full year 2008 of 2.30 bcfe consisted of 2.12 bcf and 30,656 bbls. The company’s growth rate for its full year 2008 natural gas production was 18% and its growth rate for full year 2008 oil production was 14%. The 2008 full year was Chesapeake’s 19th consecutive year of sequential production growth.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2008 fourth quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $7.13 per thousand cubic feet (mcf) and $54.80 per bbl, for a realized natural gas equivalent price of $7.29 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas and oil hedging activities during the 2008 fourth quarter generated a $2.25 gain per mcf and a $1.61 gain per bbl for a 2008 fourth quarter realized hedging gain of $445 million, or $2.09 per mcfe. Excluding hedging activity, Chesapeake’s average realized pricing basis differentials to NYMEX during the 2008 fourth quarter were a negative $2.07 per mcf and a negative $5.55 per bbl.

By comparison, average prices realized during the 2007 fourth quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.11 per mcf and $72.58 per bbl, for a realized natural gas equivalent price of $8.43 per mcfe. Realized gains from natural gas and oil hedging activities during the 2007 fourth quarter generated a $1.73 gain per mcf and a $13.66 loss per bbl for a 2007 fourth quarter realized hedging gain of $287 million, or $1.40 per mcfe. Excluding hedging activity, Chesapeake’s average realized pricing basis differentials to NYMEX during the 2007 fourth quarter were a negative $0.59 per mcf and a negative $4.44 per bbl.

For the 2008 full year, average prices realized (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.09 per mcf and $70.48 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 full year generated a $0.34 gain per mcf and a $24.56 loss per bbl for a 2008 full year realized hedging loss of $9 million, or $.01 per mcfe. Excluding hedging activity, Chesapeake’s average realized pricing basis differentials to NYMEX during the 2008 full year were a negative $1.30 per mcf and a negative $4.61 per bbl.

By comparison, average prices realized during the 2007 full year (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $8.14 per mcf and $67.50 per bbl, for a realized natural gas equivalent price of $8.40 per mcfe. Realized gains from natural gas and oil hedging activities during the 2007 full year generated a $1.85 gain per mcf and a $1.14 loss per bbl for a 2007 full year realized hedging gain of $1.2 billion, or $1.68 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2007 full year were a negative $0.57 per mcf and a negative $3.67 per bbl. During 2006, 2007 and 2008, Chesapeake's natural gas and oil hedging activities generated a total realized gain of $2.4 billion, or $1.15 per mcfe.

The following tables summarize Chesapeake's open hedge position through swaps and collars as of February 17, 2009. 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 February 17, 2009

	Natural Gas			**Oil**		
Year	**% Hedged**		**$ NYMEX**	**% Hedged**		**$ NYMEX**
2009 Total(1)	42	%	7.79	26	%	83.50
2010 Total(1)	35	%	9.43	40	%	90.25

Open Natural Gas Collar Positions as of February 17, 2009

Year	**% Hedged**		**Average Floor $ NYMEX**	**Average Ceiling $ NYMEX**
2009 Total(1)	40	%	7.30	9.00
2010 Total(1)	13	%	6.48	8.77

(1) Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $6.00 to $6.50 per mcf covering 5 bcf in 2009 and $5.45 to $6.75 per mcf covering 226 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 111 bcf in 2009 and ranging from $5.50 to $6.00 per mcf covering 18 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 $50 to $60 per bbl covering 3 mmbbls in 2009 and $60 per bbl covering 5 mmbbls in 2010.

As of February 13, 2009, Chesapeake's natural gas and oil hedging positions with a diversified group of 15 different counterparties had a positive mark-to-market value of approximately $1.6 billion.

The company's updated forecasts for 2009 and 2010 are attached to this release in an Outlook dated February 17, 2009, labeled as Schedule "A," which begins on page 23. This Outlook has been changed from the Outlook dated December 7, 2008 (attached as Schedule "B," which begins on page 28) to reflect various updated information.

Natural Gas and Oil Proved Reserves Reach 12.1 Tcfe on 1.2 Tcfe of Net Additions; Company Delivers 2008 Full Year Reserve Replacement Rate of 239% and a Drilling and Net Acquisition Cost of $1.61 per Mcfe

Chesapeake began 2008 with estimated proved reserves of 10.879 trillion cubic feet of natural gas equivalent (tcfe) and ended the year with 12.051 tcfe, an increase of 1.172 tcfe, or 11%. During 2008, Chesapeake replaced 843 bcfe of production with an estimated 2.015 tcfe of new proved reserves for a reserve replacement rate of 239%. Reserve replacement through the drillbit was 2.545 tcfe, or 302% of production. This includes 1.248 tcfe of positive performance revisions and 298 bcfe of negative revisions resulting from natural gas and oil price decreases between December 31, 2007 and December 31, 2008. Acquisitions of proved reserves completed during 2008 were 172 bcfe at a cost of $355 million, or $2.06 per mcfe, while sales of proved reserves during 2008 totaled 702 bcfe for proceeds of $2.433 billion, or $3.47 per mcfe. Sales of undeveloped leasehold during 2008 generated cash proceeds of $5.3 billion versus a cost basis of the leasehold sold of approximately $1.1 billion. Under full cost accounting rules, the difference of $4.2 billion was not reported as income but rather was credited to the full cost pool and will consequently lower the company's future DD&A rate.

Chesapeake's total drilling and net acquisition costs for 2008 were $1.61 per mcfe. This calculation excludes costs of $2.387 billion for the acquisition of unproved properties and leasehold (net of sales), $440 million for capitalized interest on unproved properties, $314 million for seismic, and $23 million relating to tax basis step-up and asset retirement obligations, and also excludes negative revisions of proved reserves from lower natural gas and oil prices. Excluding these items and acquisition and divestiture activity, Chesapeake's exploration and development costs through the drillbit during 2008 were $2.04 per mcfe (net of $271 million in drilling carries associated with the Haynesville and Fayetteville joint ventures). A complete reconciliation of proved reserves and finding and acquisition costs is presented on page 15 of this release.

During 2008, Chesapeake continued the industry's most active drilling program and drilled 1,819 gross operated wells (1,491 net wells with an average working interest of 82%) and participated in another 1,857 gross wells operated by other companies (242 net wells with an average working interest of 13%). The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during 2008, Chesapeake invested $5.043 billion in operated wells (using an average of 145 operated rigs) and $754 million in non-operated wells (using an average of 110 non-operated rigs) for total drilling, completing and equipping costs of $5.797 billion.

As of December 31, 2008, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10) and after income taxes (standardized measure) were $15.601 billion and $11.833 billion, respectively, using field differential adjusted prices based on NYMEX year-end prices of $5.71 per mcf and $44.61 per bbl. Chesapeake's PV-10 changes by approximately $400 million for every $0.10 per mcf change in natural gas prices and approximately $55 million for every $1.00 per bbl change in oil prices.

By comparison, the December 31, 2007 PV-10 and standardized measure of the company's proved reserves were $20.573 billion and $14.962 billion, respectively, using field differential adjusted prices based on NYMEX year-end prices of $6.80 per mcf and $96.00 per bbl.

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 $5.836 billion as of December 31, 2008 and $3.153 billion as of December 31, 2007.

Chesapeake's Leasehold and 3-D Seismic Inventories Increase to 15 Million Net Acres and 22 Million Acres; Risked Unproved Reserves in the Company's Inventory Reach 57 Tcfe While Unrisked Unproved Reserves Reach 165 Tcfe

Since 2000, Chesapeake has invested $12.6 billion in new leasehold and 3-D seismic acquisitions and owns the largest combined inventories of onshore leasehold (15.2 million net acres) and 3-D seismic (21.6 million acres) in the U.S. On this leasehold, Chesapeake has an estimated 4.0 tcfe of proved undeveloped reserves and approximately 57 tcfe of risked unproved reserves (165 tcfe of unrisked unproved reserves). The company is currently using 112 operated drilling rigs to further develop its inventory of approximately 36,000 net drillsites, which represents more than a 10-year inventory of drilling projects.

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

Play Type/Area	CHK Net Acreage	Est. Drilling Density (Acres)	Risk Factor	Risked Net Undrilled Wells	Est. Avg. Reserves Per Well (bcfe)	Total Proved Reserves (bcfe)	Risked Unproved Reserves (bcfe)	Total Proved and Risked Unproved Reserves (bcfe)	Unrisked Unproved Reserves (bcfe)	Current Daily Production (mmcfe)	Current Operate Rig Count
Conventional Subtotal	**4,600,000**	Various	Various	5,000	Various	**3,420**	**4,400**	**7,820**	23,200	**705**	**13**
Unconventional											
Haynesville Shale	460,000	80	40%	3,400	6.50	595	16,400	16,995	27,500	70	22
Marcellus Shale	1,250,000	80	75%	3,900	3.75	45	12,400	12,445	49,700	10	6
Barnett Shale	310,000	60	15%	2,800	2.65	2,935	4,900	7,835	6,600	610	25
Fayetteville Shale	420,000	80	20%	4,000	2.20	660	7,100	7,760	8,900	180	20
Other Unconventional	8,160,000	Various	Various	17,100	Various	4,395	12,100	16,495	49,000	780	26
Unconventional Subtotal	**10,600,000**			**31,200**		**8,630**	**52,900**	**61,530**	141,700	**1,650**	**99**
Total	**15,200,000**			**36,200**		**12,050**	**57,300**	**69,350**	**164,900**	**2,355**	**112**

During 2009 and 2010, Chesapeake anticipates generating attractive returns and delivering drillbit exploration and development costs up to 30%-40% lower than 2008 costs from a combination of lower service costs and the benefit of using approximately $2.2 billion of its more than $4 billion of joint venture drilling carries in three of its Big 4 shale plays. Accordingly, Chesapeake is targeting drilling exploration and development costs of approximately $1.25 and $1.50 per mcfe in 2009 and 2010, respectively, and believes its maintenance capital expenditure requirement in 2009 and 2010 will only be approximately 15% and 20%, respectively, of projected operating cash flow. Chesapeake anticipates directing approximately 75% of its gross drilling capital expenditures during 2009 and 2010 to its Big-4 shale plays highlighted below:

Haynesville Shale (Northwest Louisiana, East Texas): Chesapeake is the largest leasehold owner and most active driller of new wells in the Haynesville Shale play in Northwest Louisiana and East Texas. During the 2008 third quarter, Chesapeake entered into a joint venture and sold a 20% interest in its Haynesville Shale assets, including approximately 110,000 net acres of leasehold, to Plains Exploration & Production Company (NYSE:PXP) for $3.3 billion of cash and future drilling carries. Chesapeake and its partners continue to experience outstanding drilling results in the Haynesville Shale play. Chesapeake is currently producing approximately 70 mmcfe net per day (100 mmcfe gross operated) from the play and anticipates reaching approximately 300 mmcfe net per day (575 mmcfe gross operated) by year-end 2009. Chesapeake anticipates operating an average of approximately 26 rigs in 2009 to further develop its 460,000 net acres of Haynesville Shale leasehold. During 2009 and 2010, 50% of Chesapeake's drilling costs, or approximately $975 million, will be paid for by its joint venture partner PXP.

In January 2009, Chesapeake entered into an agreement with Energy Transfer Partners, L.P. (NYSE:ETP) for firm transportation capacity of approximately 1.0 bcf per day on the new Tiger Pipeline that will extend from Carthage, Texas, through the heart of the Haynesville Shale play, to an end near Delhi, Louisiana, with interconnects to at least seven interstate pipelines at various points in Louisiana. Subject to necessary regulatory approvals, the Tiger Pipeline is expected to be in service by mid-2011.

Marcellus Shale (West Virginia, Pennsylvania and New York): Chesapeake is the largest leasehold owner in the Marcellus Shale play that spans from West Virginia to southern New York and the company expects to end 2009 as the most active driller and the largest producer of natural gas from the play. During the 2008 fourth quarter, Chesapeake entered into a joint venture and sold a 32.5% interest in its Marcellus Shale assets, including approximately 600,000 net acres of leasehold, to StatoilHydro (NYSE:STO, OSE:STL) for $3.375 billion of cash and future drilling carries. The company has achieved attractive drilling results in the play to date and is planning to significantly increase its Marcellus Shale drilling activity during 2009 and 2010. Chesapeake anticipates operating an average of approximately 14 rigs in 2009 to further develop its 1.25 million net acres of Marcellus Shale leasehold. During 2009 and 2010, 75% of Chesapeake’s drilling costs, or approximately $650 million, will be paid for by its joint venture partner STO.

Barnett Shale (North Texas): The Barnett Shale is currently the largest and most prolific unconventional gas resource play in the U.S. In this play, Chesapeake is the second-largest producer of natural gas, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spots of Tarrant, Johnson and western Dallas counties. During the 2008 fourth quarter, Chesapeake’s average daily net production of 570 mmcfe in the play increased approximately 55% over the 2007 fourth quarter and approximately 10% over the 2008 third quarter. Chesapeake is currently producing approximately 610 mmcfe net per day (925 mmcfe gross operated) from the play and anticipates reaching approximately 725 mmcfe net per day (1.1 bcfe gross operated) by year-end 2009. Chesapeake anticipates operating an average of approximately 25 rigs in 2009 to further develop its 310,000 net acres of leasehold, of which 275,000 net acres are located in the prime Core and Tier 1 areas. Chesapeake is currently in discussions with several large international energy companies about a possible Barnett Shale joint venture transaction.

Fayetteville Shale (Arkansas): In the Fayetteville Shale, Chesapeake is the second-largest leasehold owner in the Core and Tier 1 areas of the play. During the 2008 third quarter, Chesapeake entered into a joint venture and sold a 25% interest in its Fayetteville Shale assets, including approximately 135,000 net acres of leasehold, and production of 45 mmcfe per day, to BP America (NYSE:BP) for $1.9 billion of cash and future drilling carries. During the 2008 fourth quarter, Chesapeake’s average daily net production of 165 mmcfe in the play increased approximately 120% over the 2007 fourth quarter. Chesapeake is currently producing approximately 180 mmcfe net per day (285 mmcfe gross operated) from the play and anticipates reaching approximately 235 mmcfe net per day (400 mmcfe gross operated) by year-end 2009. Chesapeake anticipates operating an average of approximately 20 rigs in 2009 to further develop its 420,000 net acres of Core and Tier 1 Fayetteville leasehold. During 2009, nearly all of Chesapeake’s drilling costs, or approximately $535 million, will be paid for by its joint venture partner BP.

Company Maintains Balance Sheet Flexibility and Increases Liquidity; Seeks Investment Grade Credit Metrics by Year-End 2010

During 2008, Chesapeake strengthened its balance sheet though the issuance of common stock for $2.6 billion of cash, the exchange of $455 million of preferred stock for common stock, the exchange of $765 million of contingent convertible senior notes for common stock, the sale of proved and unproved properties in multiple innovative transactions and the addition of $623 million of net income to common for the 2008 full year. As a result, the company’s net debt to book capitalization ratio decreased from 47% at December 31, 2007 to 43% at December 31, 2008.

Chesapeake ended 2008 with cash and cash equivalents on hand of approximately $1.75 billion. In the past month, Chesapeake has issued $1.425 billion in new senior notes and used the proceeds from the note offerings and cash on hand to reduce borrowings under its $3.5 billion revolving credit facility. Additionally, the company is working to generate at least $1.0 billion of excess cash in each of 2009 and 2010 through various asset monetization initiatives.

Over the next two years, Chesapeake plans to reduce its financial leverage through asset monetizations and through the growth of its proved reserve base. As a result of absolute and relative deleveraging, the company anticipates it will have investment grade credit metrics by at least year end 2010, including a key rating agency metric of long-term debt to proved reserves of less than $0.75 per mcfe.

Management Comments

Aubrey K. McClendon, Chesapeake’s Chief Executive Officer, commented, “We are pleased to report our financial and operational results for the 2008 full year and fourth quarter. Although we were required to record a non-cash after-tax impairment of our asset values of approximately $1.8 billion during the 2008 fourth quarter, we still were able to report net income available to common shareholders for the year of more than $600 million. Excluding that impairment and other non-cash items detailed in the accompanying tables, our adjusted net income for 2008 reached almost $2 billion, a record for our company.

“Looking ahead, we believe that investors will increasingly recognize Chesapeake’s competitive advantages, including our industry-leading asset position in the Big 4 shale plays, our strong hedge position and our $4 billion in drilling carries, which will enable Chesapeake to deliver operational and financial results that we believe will be among the best in the industry for years to come.”

Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday morning, February 18, 2009, at 9:00

a.m. EST. The telephone number to access the conference call is **913-312-4374** or toll-free **888-211-9951**. The passcode for the call is **4017602**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EST. For those unable to participate in the conference call, a replay will be available for audio playback from 2:00 p.m. EST on February 17, 2009 through midnight EST on March 4, 2009. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **4017602**. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of our website. 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 and anticipated asset acquisitions and 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 February 12, 2009. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; impacts the current financial crisis may have on our business and financial condition; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; our ability to compete effectively against strong independent natural gas and oil companies and majors; 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; exploration and development drilling that does not result in commercially productive reserves; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities uncertainties in evaluating natural gas and oil reserves of acquired properties and potential liabilities; the negative impact lower natural gas and oil prices could have on our ability to borrow; drilling and operating risks, including potential environmental liabilities; transportation capacity constraints and 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.

The SEC has generally permitted natural gas and oil companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms "risked and unrisked unproved reserves" to describe volumes of natural gas and oil reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines may prohibit us from including in filings with the SEC. These estimates 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. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third-party engineers or appraisers.

Chesapeake Energy Corporation is the largest independent 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 Barnett Shale, Haynesville Shale, Fayetteville Shale, Marcellus Shale, Anadarko Basin, Arkoma Basin, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and East Texas 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:	**December 31, 2008**		**December 31, 2007**	
	$	**$/mcfe**	**$**	**$/mcfe**
REVENUES:				
Natural gas and oil sales	2,271	10.66	1,460	7.15
Natural gas and oil marketing sales	664	3.12	594	2.91

Service operations revenue	46	0.21	35	0.17
Total Revenues	2,981	13.99	2,089	10.23
OPERATING COSTS:				
Production expenses	231	1.09	180	0.88
Production taxes	35	0.16	64	0.32
General and administrative expenses	89	0.42	75	0.37
Natural gas and oil marketing expenses	641	3.01	575	2.81
Service operations expense	38	0.18	27	0.13
Natural gas and oil depreciation, depletion and amortization	452	2.12	521	2.55
Depreciation and amortization of other assets	52	0.24	33	0.16
Impairment of natural gas and oil properties and other fixed assets	2,830	13.28	—	—
Total Operating Costs	4,368	20.50	1,475	7.22
INCOME (LOSS) FROM OPERATIONS	(1,387)	(6.51)	614	3.01
OTHER INCOME (EXPENSE):				
Interest and other income	12	0.06	3	0.01
Interest expense	(102)	(0.48)	(128)	(0.63)
Impairment of investments	(180)	(0.85)	—	—
Gain on exchanges or repurchases of Chesapeake debt	268	1.26	—	—
Total Other Income (Expense)	(2)	(0.01)	(125)	(0.62)
INCOME (LOSS) BEFORE INCOME TAXES	(1,389)	(6.52)	489	2.39
Income Tax Expense (Benefit):				
Current	227	1.07	9	0.04
Deferred	(756)	(3.55)	177	0.87
Total Income Tax Expense (Benefit)	(529)	(2.48)	186	0.91
NET INCOME (LOSS)	(860)	(4.04)	303	1.48
Preferred stock dividends	(6)	(0.03)	(17)	(0.08)
Loss on conversion/exchange of preferred stock	—	—	(128)	(0.63)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	(866)	(4.07)	158	0.77
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$(1.51)		$0.34	
Assuming dilution	$(1.51)		$0.33	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	575		468	
Assuming dilution	575		476	

CHESAPEAKE ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

($ in millions, except per-share and unit data)

(unaudited)

TWELVE MONTHS ENDED:	December 31, 2008		December 31, 2007	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Natural gas and oil sales	7,858	9.32	5,624	7.88
Natural gas and oil marketing sales	3,598	4.27	2,040	2.86
Service operations revenue	173	0.21	136	0.19
Total Revenues	11,629	13.80	7,800	10.93
OPERATING COSTS:				
Production expenses	889	1.05	640	0.90
Production taxes	284	0.34	216	0.30
General and administrative expenses	377	0.45	243	0.34
Natural gas and oil marketing expenses	3,505	4.16	1,969	2.76
Service operations expense	143	0.17	94	0.13
Natural gas and oil depreciation, depletion and amortization	1,970	2.34	1,835	2.57
Depreciation and amortization of other assets	177	0.21	154	0.22
Impairment of natural gas and oil properties and other fixed assets	2,830	3.35	—	—
Total Operating Costs	10,175	12.07	5,151	7.22

INCOME FROM OPERATIONS	1,454	1.73	2,649	3.71
OTHER INCOME (EXPENSE):				
Interest and other income	(11)	(0.01)	15	0.02
Interest expense	(314)	(0.38)	(406)	(0.57)
Gain on exchanges or repurchases of Chesapeake debt	237	0.28	—	—
Impairment of investments	(180)	(0.21)	—	—
Gain on sale of investments	—	—	83	0.12
Total Other Income (Expense)	(268)	(0.32)	(308)	(0.43)
INCOME BEFORE INCOME TAXES	1,186	1.41	2,341	3.28
Income Tax Expense:				
Current	423	0.50	29	0.04
Deferred	40	0.05	861	1.21
Total Income Tax Expense	463	0.55	890	1.25
NET INCOME	723	0.86	1,451	2.03
Preferred stock dividends	(33)	(0.04)	(94)	(0.13)
Loss on conversion/exchange of preferred stock	(67)	(0.08)	(128)	(0.18)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	623	0.74	1,229	1.72
EARNINGS PER COMMON SHARE:				
Basic	$1.16		$2.69	
Assuming dilution	$1.14		$2.62	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	536		456	
Assuming dilution	545		487	

CHESAPEAKE ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

($ in millions)

(unaudited)

	December 31, 2008	December 31, 2007
Cash and cash equivalents	$ 1,749	$ 1
Other current assets	2,543	1,395
Total Current Assets	4,292	1,396
Property and equipment (net)	33,145	28,337
Other assets	1,007	1,001
Total Assets	$ 38,444	$ 30,734
Current liabilities	$ 3,621	$ 2,761
Long-term debt, net	14,184	10,950
Asset retirement obligation	269	236
Other long-term liabilities	310	691
Deferred tax liability	3,763	3,966
Total Liabilities	22,147	18,604
Stockholders' Equity	16,297	12,130
Total Liabilities & Stockholders' Equity	$ 38,444	$ 30,734
Common Shares Outstanding (in millions)	607	511

CHESAPEAKE ENERGY CORPORATION

CAPITALIZATION

($ in millions)

(unaudited)

	December 31, 2008	% of Total Book Capitalization	December 31, 2007	% of Total Book Capitalization
Total debt, net cash	$ 12,435	43 %	$ 10,949	47 %

Stockholders' equity	16,297	57 %	12,130	53 %
Total	$ 28,732	100 %	$ 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	$ 5,797	2,843 (a)	2.04
Acquisition of proved properties	355	172	2.06
Sale of proved properties	(2,433)	(702)	3.47
Drilling and net acquisition cost	3,719	2,313	1.61
Revisions – price	—	(298)	—
Acquisition of unproved properties and leasehold	7,689	—	—
Sale of unproved properties and leasehold	(5,302)	—	—
Net leasehold and unproved property acquisition	2,387	—	—
Capitalized interest on leasehold and unproved property			
Capitalized interest on leasehold and unproved property	440	—	—
Geological and geophysical costs	314	—	—
Geological, geophysical and capitalized interest	754	—	—
Subtotal	6,860	2,015	3.40
Tax basis step-up	13	—	—
Asset retirement obligation and other	10	—	—
Total	$ 6,883	2,015	3.42

(a) Includes 1.248 tcfe of performance revisions (1.367 tcfe relating to infill drilling and increased density locations and (119) bcfe of other performance related revisions) and excludes downward revisions of 298 bcfe resulting from natural gas and oil price declines between December 31, 2007 and 2008.

CHESAPEAKE ENERGY CORPORATION

ROLL-FORWARD OF PROVED RESERVES

TWELVE MONTHS ENDED DECEMBER 31, 2008

(unaudited)

	Bcfe
Beginning balance, 01/01/08	10,879
Production	(843)
Acquisitions	172
Divestitures	(702)
Revisions – performance	1,248
Revisions – price	(298)
Extensions and discoveries	1,595
Ending balance, 12/31/08	12,051
Reserve replacement	2,015
Reserve replacement ratio [a]	239 %

(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 December 31, 2008	2007	TWELVE MONTHS ENDED December 31, 2008	2007
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 957	$ 1,199	$ 6,003	$ 4,117
Natural gas derivatives – realized gains (losses)	441	324	267	1,214
Natural gas derivatives – unrealized gains (losses)	195	(81)	521	(139)
Total Natural Gas Sales	1,593	1,442	6,791	5,192
Oil sales	151	236	1,066	678
Oil derivatives – realized gains (losses)	5	(38)	(275)	(11)
Oil derivatives – unrealized gains (losses)	522	(180)	276	(235)
Total Oil Sales	678	18	1,067	432
Total Natural Gas and Oil Sales	$ 2,271	$ 1,460	$ 7,858	$ 5,624
Average Sales Price – excluding gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 4.88	$ 6.38	$ 7.74	$ 6.29
Oil ($ per bbl)	$ 53.19	$ 86.24	$ 95.04	$ 68.64
Natural gas equivalent ($ per mcfe)	$ 5.20	$ 7.03	$ 8.39	$ 6.71
Average Sales Price – excluding unrealized gains (losses) on derivatives:				
Natural gas ($ per mcf)	$ 7.13	$ 8.11	$ 8.09	$ 8.14
Oil ($ per bbl)	$ 54.80	$ 72.58	$ 70.48	$ 67.50
Natural gas equivalent ($ per mcfe)	$ 7.29	$ 8.43	$ 8.38	$ 8.40
Interest Expense ($ in millions):				
Interest	$ 15	$ 99	$ 235	$ 365
Derivatives – realized (gains) losses	(7)	1	(6)	1
Derivatives – unrealized (gains) losses	94	28	85	40
Total Interest Expense	$ 102	$ 128	$ 314	406

CHESAPEAKE ENERGY CORPORATION

CONDENSED CONSOLIDATED CASH FLOW DATA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	December 31, 2008	December 31, 2007
Beginning cash	$ 1,964	$ 2
Cash provided by operating activities	931	1,544
Cash (used in) investing activities	(1,643)	(1,434)
Cash provided by (used in) financing activities	497	(111)
Ending cash	1,749	1

TWELVE MONTHS ENDED:	December 31, 2008	December 31, 2007
Beginning cash	$ 1	$ 3
Cash provided by operating activities	5,236	4,932
Cash (used in) investing activities	(9,844)	(7,922)
Cash provided by financing activities	6,356	2,988
Ending cash	1,749	1

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	December 31, 2008	September 30, 2008	December 31, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 931	$ 1,550	$ 1,544
Adjustments:			
Changes in assets and liabilities	84	(343)	(209)

OPERATING CASH FLOW*	$ 1,015	$ 1,207	$ 1,335

*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.

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

THREE MONTHS ENDED:	**December 31, 2008**	**September 30, 2008**	**December 31, 2007**
NET INCOME (LOSS)	$ (860)	$ 3,313	$ 303
Income tax expense (benefit)	(529)	2,074	186
Interest expense	102	48	128
Depreciation and amortization of other assets	52	48	33
Natural gas and oil depreciation, depletion and amortization	452	480	521
EBITDA**	$ (783)	$ 5,963	$ 1,171

**Ebitda represents net income (loss) before income tax expense, interest expense and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP. Ebitda is reconciled to cash provided by operating activities as follows:

THREE MONTHS ENDED:	**December 31, 2008**	**September 30, 2008**	**December 31, 2007**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 931	$ 1,550	$ 1,544
Changes in assets and liabilities	84	(343)	(209)
Interest expense	102	48	128
Unrealized gains (losses) on natural gas and oil derivatives	717	4,618	(261)
Impairment of natural gas and oil properties and other assets	(2,830)	—	—
Impairment of investments	(180)	—	—
Other non-cash items	393	90	(31)
EBITDA	$ (783)	$ 5,963	$ 1,171

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF OPERATING CASH FLOW AND EBITDA

($ in millions)

(unaudited)

TWELVE MONTHS ENDED:	**December 31, 2008**	**December 31, 2007**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 5,236	$ 4,932
Adjustments:		
Changes in assets and liabilities	(58)	(299)
OPERATING CASH FLOW*	$ 5,178	$ 4,633

*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.

TWELVE MONTHS ENDED:	**December 31, 2008**	**December 31, 2007**
NET INCOME	$ 723	$ 1,451
Income tax expense (benefit)	463	890
Interest expense	314	406
Depreciation and amortization of other assets	177	154
Natural gas and oil depreciation, depletion and amortization	1,970	1,835
EBITDA**	$ 3,647	$ 4,736

**Ebitda represents net income (loss) before income tax expense, interest expense and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreements and is used in the financial covenants in our bank credit agreements and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP. Ebitda is reconciled to cash provided by operating activities as follows:

TWELVE MONTHS ENDED:	**December 31, 2008**	**December 31, 2007**
CASH PROVIDED BY OPERATING ACTIVITIES	$ 5,236	$ 4,932
Changes in assets and liabilities	(58)	(299)
Interest expense	314	406
Unrealized gains (losses) on natural gas and oil derivatives	797	(375)
Impairment of natural gas and oil properties and other assets	(2,830)	—
Impairment of investments	(180)	—
Other noncash items	368	72
EBITDA	$ 3,647	$ 4,736

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON SHAREHOLDERS

($ in millions, except per-share data)

(unaudited)

THREE MONTHS ENDED:	**December 31, 2008**	**September 30, 2008**	**December 31, 2007**
Net income (loss) available to common shareholders	$ (866)	$ 3,282	$ 158
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	(380)	(2,846)	180
Impairment of natural gas and oil properties and other fixed assets, net of tax	1,726	—	—
Impairment of investments, net of tax	110	—	—
(Gain) loss on exchanges or repurchases of Chesapeake debt, net of tax	(163)	19	—
Consent fees on senior notes, net of tax	—	6	—
Loss on conversion/exchange of preferred stock	—	25	128
Adjusted net income available to common shareholders*	427	486	466
Preferred stock dividends	6	6	17
Interest on 2.75% contingent convertible notes, net of tax	—	3	—
Interest on 2.50% contingent convertible notes, net of tax	—	7	—
Total adjusted net income	$ 433	$ 502	$ 483
Weighted average fully diluted shares outstanding**	590	589	520

Adjusted earnings per share assuming dilution*	$ 0.73	$ 0.85	$ 0.93

*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.

**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:	**December 31, 2008**	**September 30, 2008**	**December 31, 2007**
EBITDA	$ (783)	$ 5,963	$ 1,171
Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	(717)	(4,618)	261
(Gain) loss on exchanges or repurchases of Chesapeake debt	(268)	31	—
Impairment of natural gas and oil properties and other fixed assets	2,830	—	—
Impairment of investments	180	—	—
Consent fees on senior notes	—	10	—
Adjusted ebitda*	$ 1,242	$ 1,386	$ 1,432

*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)

TWELVE MONTHS ENDED:	**December 31, 2008**	**December 31, 2007**
Net income available to common shareholders	$ 623	$ 1,229
Adjustments:		
Unrealized (gains) losses on derivatives, net of tax	(434)	257
Impairment of natural gas and oil properties and other fixed assets, net of tax	1,726	—
Impairment of investments, net of tax	110	—
(Gain) loss on exchanges or repurchases of Chesapeake debt, net of tax	(144)	—
Gain on sale of investment, net of cash	—	(51)
Loss on conversion/exchange of preferred stock	67	128
Consent fees on senior notes, net of tax	6	—
Adjusted net income available to common shareholders*	1,954	1,563

Preferred stock dividends	23	94
Interest on 2.75% contingent convertible notes, net of tax	6	—
Interest on 2.50% contingent convertible notes, net of tax	6	—
Total adjusted net income	$ 1,999	$ 1,657
Weighted average fully diluted shares outstanding**	562	517
Adjusted earnings per share assuming dilution*	$ 3.55	$ 3.21

*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.

**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)

TWELVE MONTHS ENDED:	**December 31, 2008**	**December 31, 2007**
EBITDA	$ 3,647	$ 4,736
Adjustments, before tax:		
Unrealized (gains) losses on natural gas and oil derivatives	(797)	375
(Gain) loss on exchanges or repurchases of Chesapeake debt	(237)	—
Impairment of natural gas and oil properties and other fixed assets	2,830	—
Impairment of investments	180	—
Consent fees on senior notes	10	—
Gain on sale of investment	—	(83)
Adjusted ebitda*	$ 5,633	$ 5,028

*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 PV-10

($ in millions)

(unaudited)

	December 31, 2008	**December 31, 2007**
Standardized measure of discounted future net cash flows	$ 11,833	$ 14,962
Discounted future cash flows for income taxes	3,768	5,611
Discounted future net cash flows before income taxes (PV-10)	$ 15,601	$ 20,573

PV-10 is discounted (at 10%) future net cash flows before income taxes. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and is calculated in accordance with SFAS 69. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependent on the unique tax situation of each individual company.

The company’s December 31, 2008 PV-10 and standardized measure were calculated using field differential adjusted prices based on NYMEX year-end prices of $5.71 per mcf and $44.61 per bbl. The company’s December 31, 2007 PV-10 and standardized measure were calculated using field differential adjusted prices based on NYMEX year-end prices of $6.80 per mcf and $96.00 per bbl.

SCHEDULE “A”

CHESAPEAKE’S OUTLOOK AS OF FEBRUARY 17, 2009

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 February 17, 2009, we are using the following key assumptions in our projections for 2009 and 2010.

The primary changes from our December 7, 2009 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 natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been reduced; and

3) Certain cost, cash income tax and book income tax rate assumptions have been updated; and

4) The company has discontinued its practice of providing quarterly estimates.

	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production		
Natural gas – bcf	803 – 813	***904 – 944***
Oil – mbbls	12,000	***12,000***
Natural gas equivalent – bcfe	875 – 885	976 – 1,016
Daily natural gas equivalent midpoint – mmcfe	2,410	2,730
Year-over-year estimated production increase	4.8 %	13.3 %
NYMEX Prices [(a)] (for calculation of realized hedging effects only):		
Natural gas - $/mcf	***$5.80***	***$7.00***
Oil - $/bbl	***$47.66***	***$70.00***
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	***$1.67***	***$1.15***
Oil - $/bbl	***$0.49***	***$5.71***
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	***15 – 20 %***	***15 – 20 %***
Oil - $/bbl	***5 – 7 %***	***5 – 7 %***
Operating Costs per Mcfe of Projected Production:		
Production expense	$ 1.10 – 1.20	$ 1.15 – 1.25
Production taxes (~ 5% of O&G revenues) [(b)]	***$0.25 – 0.35***	***$0.30 – 0.35***
General and administrative[(c)]	$ 0.33 – 0.37	$ 0.33 – 0.37
Stock-based compensation (non-cash)	$ 0.10 – 0.12	$ 0.10 – 0.12
DD&A of natural gas and oil assets	***$1.90 – 2.00***	***$1.90 – 2.00***
Depreciation of other assets	***$0.24 – 0.28***	***$0.24 – 0.28***
Interest expense[(d)]	***$0.30 – 0.35***	$ 0.35 – 0.40
Other Income per Mcfe:		
Natural gas and oil marketing income	$ 0.09 – 0.11	$ 0.09 – 0.11
Service operations income	$ 0.04 – 0.06	$ 0.04 – 0.06
Book Tax Rate	***39 %***	***39 %***
Cash Income Taxes – in millions	***–***	***$100 – 200***
Equivalent Shares Outstanding – in millions:		
Basic	***600 – 605***	***610 – 615***
Diluted	***610 – 615***	***620 – 625***

Cash Flow Projections – in millions	Year Ending 12/31/2009	Year Ending 12/31/2010
Net inflows:		
Operating cash flow before changes in assets and liabilities[(e)(f)]	***$3,900 – 4,000***	***$5,000 – 5,400***

Leasehold and producing property transactions:		
Sale of leasehold and producing properties	***$1,500 – 2,000***	***$1,000 – 1,500***
Acquisition of leasehold and producing properties	***($350 - $500)***	***($350 - $500)***
Net leasehold and producing property transactions	***$1,050 – 1,500***	***$600 – 1,000***
Midstream financings	***$500 – 600***	***$500 – 600***
Proceeds from investments and other	***$300***	***–***
Total Cash Inflows	***$5,850 – 6,400***	***$6,150 – 7,000***
Net outflows:		
Drilling	***$2,800 – 3,000***	$ 3,500 – 3,800
Geophysical costs	$ 100 – 125	$ 100 – 125
Midstream infrastructure and compression	***$600 – 700***	***$400 – 500***
Other PP&E	***$300 – 350***	$ 200 – 250
Dividends, senior notes redemption, capitalized interest, etc.	***$600 – 800***	$ 500 – 600
Cash income taxes	***$175 – 200***	$ 100 – 200
Total Cash Outflows	***$4,575 – 5,175***	***$4,800 – 5,475***
Net Cash Change	***$1,225 –1,275***	***$1,350 – 1,525***

(a) NYMEX natural gas prices have been updated for actual contract prices through February 2009.

(b) Severance tax per mcfe is based on NYMEX prices of $47.66 per bbl of oil and $6.00 to $7.50 per mcf of natural gas during 2009 and $70.00 per bbl of oil and $7.00 to $8.50 per mcf of natural gas during 2010.

(c) Excludes expenses associated with noncash stock compensation.

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

(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 natural gas prices of $6.00 to $7.00 per mcf and NYMEX oil prices of $50.00 per bbl in 2009 and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $70.00 per bbl in 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:

	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 Trades ($ millions)	Total Lifted Gain (Loss) per Mcf of Estimated Total Natural Gas Production
Q1 2009	***94.2***	***$ 8.02***			***$ 59.4***	
Q2 2009	***57.5***	***$ 7.81***			***$ 30.8***	
Q3 2009	***59.1***	***$ 7.97***			***$ 25.8***	
Q4 2009	***111.6***	***$ 7.55***			***$ 26.4***	
Total 2009(1)	**322.4**	**$ 7.81**	808	**40 %**	***$ 142.4***	***$ 0.18***
Total 2010(1)	***324.7***	***$ 9.43***	***924***	***35 %***	***$ (44.3)***	***$ (0.05)***

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure at prices ranging from $6.00 to $6.50 covering 5.5 bcf in 2009 and $5.45 to $6.75 covering 226 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
Q1 2009	***50.1***	***$ 7.92***	***$ 9.57***		
Q2 2009	***101.2***	***$ 7.08***	***$ 8.90***		
Q3 2009	***108.3***	***$ 7.11***	***$ 8.85***		
Q4 2009	***62.1***	***$ 7.48***	***$ 8.96***		
Total 2009(1)	***321.7***	***$ 7.30***	***$ 9.00***	808	***40 %***
Total 2010(1)	***120.3***	***$ 6.48***	***$ 8.77***	***924***	***13 %***

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 111 bcf in 2009 and ranging from $5.50 to $6.00 covering 18 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
Q1 2009	***31.1***	***$ 9.54***	***$ 1.00***		
Q2 2009	***27.8***	***$ 8.89***	***$ 1.08***		
Q3 2009	***27.2***	***$ 8.81***	***$ 1.12***		
Q4 2009	***29.0***	***$ 9.03***	***$ 1.03***		
Total 2009	***115.1***	***$ 9.08***	***$ 1.05***	808	***14 %***
Total 2010	231.8	$ 10.77	$ 0.96	***924***	25 %

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

	Mid-Continent Volume in Bcf's	NYMEX less*:	Appalachia Volume in Bcf's	NYMEX plus*:
2009	77.1	***1.27***	16.9	0.28
2010	—	—	10.2	0.26
2011	45.1	***0.82***	12.1	0.25
2012	43.2	***0.85***	—	—
Totals	165.4	$ 1.04	39.2	$ 0.27

* 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 $592 million ($[45] million as of December 31, 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
Q1 2009	4.5	$ 5.18	$ 8.63	($3.45)		
Q2 2009	4.6	$ 5.18	$ 6.87	($1.69)		
Q3 2009	4.6	$ 5.18	$ 6.89	($1.71)		
Q4 2009	4.6	$ 5.18	$ 7.32	($2.14)		
Total 2009	18.3	$ 5.18	$ 7.28	($2.10)	808	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 Gains from Lifted Trades ($ millions)	Total Lifted Gains per bbl of Estimated Total Oil Production
Q1 2009	***363***	***$ 73.53***			***$ 17.5***	
Q2 2009	***637***	***$ 77.38***			***$ 18.6***	
Q3 2009	***1,058***	***$ 87.05***			***$ 3.4***	
Q4 2009	***1,058***	***$ 87.04***			***$ 3.3***	
Total 2009(1)	***3,116***	***$ 83.50***	12,000	***26 %***	***$ 42.9***	***$ 3.19***
Total 2010(1)	4,745	$ 90.25	***12,000***	***40 %***	—	—

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $50.00 to $60.00 covering 3 mmbbls in 2009 and $60.00 covering 5 mmbbls in 2010.

SCHEDULE “B”

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF DECEMBER 7, 2008

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 17, 2009

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 December 7, 2008, we are using the following key assumptions in our projections for the 2008 fourth quarter and the full years 2009 and 2010.

The primary changes from our November 3, 2008 Outlook are in ***italicized bold*** and are explained as follows:

1) Our assumptions for asset sale, financing and other cash inflows as well as capital expenditures and other cash outflows have been updated for the 2008 fourth quarter and full years 2009 and 2010;

2) Our natural gas production assumptions for the full years 2009 and 2010 have been reduced to reflect reduced drilling capital expenditures;

3) The projected effects of changes in our hedging positions have been updated;

4) Our NYMEX natural gas and oil price assumptions for realized hedging effects and estimating future operating cash flow have been reduced for the 2008 fourth quarter and full year 2009;

5) Certain cost and cash income tax assumptions have been updated; and

6) We have updated our average shares outstanding assumptions for the contingent convertible note exchanges completed during the 2008 fourth quarter.

	Quarter Ending 12/31/2008	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production[a]			
Natural gas – bcf	188 – 192	***803 – 813***	***898 – 938***
Oil – mbbls	2,825	12,000	13,000
Natural gas equivalent – bcfe	205 – 209	***875 – 885***	***976 – 1,016***
Daily natural gas equivalent midpoint – mmcfe	2,250	***2,410***	***2,730***
NYMEX Prices[b] (for calculation of realized hedging effects only):			
Natural gas - $/mcf	***$6.95***	***$7.00***	$8.00
Oil - $/bbl	***$63.91***	***$70.00***	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Natural gas - $/mcf	***$2.06***	***$1.16***	***$0.95***
Oil - $/bbl	***$2.40***	***$7.08***	$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[c]	$0.30 – 0.35	***$0.30 – 0.35***	$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 %
Equivalent Shares Outstanding – in millions:			
Basic	***573 – 578***	***588 – 593***	***598 – 603***
Diluted	***589 – 594***	***603 – 608***	***611 – 616***

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 – 1,300***	***$4,800 – 5,100***	***$5,700 - 6,100***
Leasehold and producing property transactions:			
Sale of leasehold and producing properties[a]	***$1,400 – 1,450***	***$500 – 1,000***	***$500 – 1,000***
Sale of producing properties via VPP's[a]	***$425 – 475***	***$900 – 1,000***	***$450 – 500***
Acquisition of leasehold and producing properties			

Acquisition of leasehold and producing properties	***($900 – 1,000)***	***($300 – 350)***	***($250 – 300)***
Net leasehold and producing property transactions	***$925 – 925***	***$1,100 – 1,650***	***$700 – 1,200***
Debt and equity offerings	–	–	–
Midstream financing and system sale or equity partner investment	***$460***	***$500 – 600***	***$500 – 600***
Proceeds from investments and other	–	–	–
Total Cash Inflows	***$2,635 – 2,685***	***$6,400 – 7,350***	***$6,900 – 7,900***
Net outflows:			
Drilling	***$1,400 – 1,500***	***$2,800 – 3,100***	***$3,500 – 3,800***
Geophysical costs	$ 75	***$100 – 125***	***$100 – 125***
Midstream infrastructure and compression	$ 300 – 325	***$500 – 600***	***$500 – 600***
Other PP&E	***$100 – 150***	***$200 – 250***	***$200 – 250***
Dividends, senior notes redemption, capitalized interest, etc.	$ 150 – 200	***$500 – 600***	***$500 – 600***
Cash income taxes	***$300 – 325***	***$250 – 275***	***$100 – 200***
Total Cash Outflows	***$2,325 – 2,575***	***$4,350 – 4,950***	***$4,900 – 5,575***
Net Cash Change	***$110 – 310***	***$2,050 – 2,400***	***$2,000 – 2,325***

(a) The 2008 fourth quarter production and cash flow forecasts reflect the completed Marcellus Shale joint venture with StatoilHydro, including $1.25 billion of cash received upon closing, the completed sale of undeveloped leasehold for approximately $200 million and the anticipated sale of producing properties for approximately $450 million in a volumetric production payment (VPP) transaction. The production and cash flow forecasts reflect anticipated sales by the company of producing properties in VPP transactions and/or leasehold for approximately $1.7 billion in 2009 and approximately $1.2 billion in 2010.

(b) NYMEX natural gas and oil prices have been updated for actual contract prices through December 2008 and October 2008, respectively.

(c) Severance tax per mcfe is based on approximately 5% of natural gas and oil revenues.

(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 $6.95 per mcf and NYMEX oil prices of $63.91 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 $70.00 per bbl in 2009 and NYMEX natural gas prices of $7.00 to $8.00 per mcf and NYMEX oil prices of $80.00 per bbl in 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:

	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)	Total Lifted Gain (Loss) per Mcf of Estimated Total Natural Gas Production
Q4 2008	***103.7***	***$ 9.21***	190	***55***	***%***	$ 85.2	$ 0.45
Total 2009(1)	***284.2***	***$ 9.21***	***808***	***35***	***%***	($36.3)	($0.04)
Total 2010(1)	422.6	$ 9.58	***918***	***46***	***%***	$ 33.9	$ 0.04

(1) Certain hedging arrangements include knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.75 to $6.75 covering 93 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)	***309.8***	***$ 7.36***	***$ 9.06***	***808***	***38***	***%***
Total 2010(1)	25.6	$ 7.71	$ 11.46	***918***	***3***	***%***

(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	***808***	***27***	***%***
Total 2010	231.8	$ 10.77	$ 0.72	***918***	***25***	***%***

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less*:	Volume in Bcf's	NYMEX plus*:

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

* 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)	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)	190	5 %
Total 2009	18.3	$ 5.18	$ 7.28	($2.10)	***808***	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 Gains (Losses) from Lifted Swaps ($ millions)	Total Lifted Gain (Loss) per bbl of 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.

Source: Chesapeake Energy Corporation

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