NEWS RELEASE

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

Company Reports 2008 First Quarter Production of 2.2 Bcfe per Day; Increase of 31% Over 2007 First Quarter Production 2008 First Quarter Net Loss to Common Shareholders of $143 Million, or $0.29 per Fully Diluted Common Share Reported; Adjusted Net Income Available to Common Shareholders Increases 32% Over 2007 First Quarter to $561 Million, or $1.09 per Fully Diluted Common Share, a Company Record Proved Reserves Reach Record Level of 11.5 Tcfe and Increase 6% Year-to-Date; Company Delivers First Quarter Reserve Replacement Rate of 395% from 601 Bcfe of Net Additions at a Drilling and Net Acquisition Cost of $1.95 per Mcfe Chesapeake Agrees to Sell 94 Bcfe of Proved Reserves for Proceeds of $623 Million, or $6.63 per Mcfe, in a Volumetric Production Payment Transaction; Company Announces Plans to Sell Remaining Arkoma Basin Woodford Shale Properties for Anticipated Proceeds of Over $1.5 Billion

OKLAHOMA CITY--(BUSINESS WIRE)--May 1, 2008--In BW6354 issued May 1, 2008: Reissuing release to replace operational results table for the Fayetteville Shale play.

The corrected release reads:

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Proved Reserves Reach Record Level of 11.5 Tcfe and Increase 6% Year-to-Date; Company Delivers First Quarter Reserve Replacement Rate of 395% from 601 Bcfe of Net Additions at a Drilling and Net Acquisition Cost of $1.95 per Mcfe

Chesapeake Agrees to Sell 94 Bcfe of Proved Reserves for Proceeds of $623 Million, or $6.63 per Mcfe, in a Volumetric Production Payment Transaction; Company Announces Plans to Sell Remaining Arkoma Basin Woodford Shale Properties for Anticipated Proceeds of Over $1.5 Billion

Chesapeake Energy Corporation (NYSE:CHK) today announced financial and operating results for the 2008 first quarter. Due to an unrealized non-cash after-tax mark-to-market loss of $704 million from future period natural gas and oil and interest rate hedges primarily as a result of higher natural gas and oil prices as of March 31, 2008 compared to December 31, 2007, Chesapeake reported a net loss to common shareholders during the quarter of $143 million ($0.29 per fully diluted common share), operating cash flow of $1.512 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $438 million (defined as net income (loss) before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.611 billion and production of 204 billion cubic feet of natural gas equivalent (bcfe).

The company's $704 million loss referenced above was offset by $132 million in realized after-tax cash gains from hedging activities for actual volumes produced during the quarter. Further, this unrealized loss is an item that is typically not included in published estimates of the company's financial results by certain securities analysts. Excluding this item, Chesapeake's adjusted net income to common shareholders in the 2008 first quarter was $561 million ($1.09 per fully diluted common share) and adjusted ebitda was $1.570 billion, increases of 32% and 27%, respectively, over the 2007 first quarter. This adjusted net income to common shareholders for the quarter of $1.09 per share is the highest achieved in the company's history. The excluded item does 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 - 18 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2008 first quarter and compares them to results during the 2007 fourth quarter and the 2007 first quarter. The 2008 first quarter results reflect the sale of 55 million cubic feet of natural gas equivalent (mmcfe) per day of production in a volumetric production payment (VPP) transaction as of December 31, 2007.

	Three Months Ended:		
	3/31/08	12/31/07	3/31/07
Average daily production (in mmcfe)	2,244	2,219	1,707
Natural gas as % of total production	92	92	92
Natural gas production (in bcf)	187.8	187.8	140.8
Average realized natural gas price ($/mcf) (a)	9.05	8.11	9.26
Oil production (in mbbls)	2,746	2,735	2,143
Average realized oil price ($/bbl) (a)	74.73	72.58	61.13
Natural gas equivalent production (in bcfe)	204.2	204.2	153.7
Natural gas equivalent realized price ($/mcfe) (a)	9.33	8.43	9.33
Natural gas and oil marketing income ($/mcfe)	.11	.09	.10
Service operations income ($/mcfe)	.03	.04	.08
Production expenses ($/mcfe)	(.98)	(.88)	(.93)
Production taxes ($/mcfe)	(.37)	(.32)	(.27)
General and administrative costs ($/mcfe) (b)	(.29)	(.29)	(.27)
Stock-based compensation ($/mcfe)	(.09)	(.08)	(.07)
DD&A of natural gas and oil properties ($/mcfe)	(2.52)	(2.55)	(2.56)
D&A of other assets ($/mcfe)	(.18)	(.16)	(.23)
Interest expense ($/mcfe) (a)	(.43)	(.49)	(.50)
Operating cash flow ($ in millions) (c)	1,512	1,322	1,124
Operating cash flow ($/mcfe)	7.40	6.48	7.31
Adjusted ebitda ($ in millions) (d)	1,570	1,432	1,234
Adjusted ebitda ($/mcfe)	7.69	7.01	8.03
Net income (loss) to common shareholders ($ in millions)	(143)	158	232
Earnings (loss) per share - assuming dilution ($)	(.29)	.33	.50
Adjusted net income to common shareholders ($ in millions) (e)	561	466	425
Adjusted earnings per share - assuming dilution ($)	1.09	.93	.87

(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 non-cash 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 18

(e) defined as net income (loss) available to common shareholders, as adjusted to remove the effects of certain items detailed on page 18

Natural Gas and Oil Production Sets Record for 27th Consecutive Quarter; 2008 First Quarter Average Daily Production Increases 31% over 2007 First Quarter Production

Daily production for the 2008 first quarter averaged 2.244 bcfe, an increase of 25 mmcfe, or 1%, over the 2.219 bcfe produced per day in the 2007 fourth quarter and an increase of 537 mmcfe, or 31%, over the

1.707 bcfe produced per day in the 2007 first quarter. Adjusted for the company's year-end 2007 VPP sale, Chesapeake's sequential and year-over-year production growth rates were 4% and 35%, respectively. Chesapeake's average daily production for the 2008 first quarter consisted of 2.063 billion cubic feet of natural gas (bcf) and 30,176 barrels of oil and natural gas liquids (bbls). The company's 2008 first quarter production of 204.2 bcfe was comprised of 187.8 bcf (92% on a natural gas equivalent basis) and 2.75 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis).

The 2008 first quarter was Chesapeake's 27th consecutive quarter of sequential U.S. production growth. Over these 27 quarters, Chesapeake's U.S. production has increased 467%, for an average compound quarterly growth rate of 6.6% and an average compound annual growth rate of 29.2%.

Natural Gas and Oil Proved Reserves Reach Record Level of 11.5 Tcfe; Company Adds 601 Bcfe of Net Proved Reserves for a Reserve Replacement Rate of 395% at an Average Drilling and Net Acquisition Cost of $1.95 per Mcfe

Chesapeake began 2008 with estimated proved reserves of 10.879 trillion cubic feet of natural gas equivalent (tcfe) and ended the first quarter with 11.480 tcfe, an increase of 601 bcfe, or 6%. During the quarter, Chesapeake replaced its 204 bcfe of production with an estimated 805 bcfe of new proved reserves for a reserve replacement rate of 395%. Reserve replacement through the drillbit was 798 bcfe, or 391% of production. This includes 365 bcfe of positive performance revisions (including 342 bcfe related to infill drilling and increased density locations) and 112 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and March 31, 2008. Acquisitions of proved reserves completed during the quarter were 39 bcfe at a cost of $63 million, or $1.59 per mcfe, while sales of proved reserves during the quarter totaled 32 bcfe for proceeds of $86 million, or $2.72 per mcfe. Sales of undeveloped leasehold during the quarter generated proceeds of $159 million.

Chesapeake's total drilling and net acquisition costs for the quarter were $1.95 per mcfe. This calculation excludes costs of $694 million for the acquisition of unproved properties and leasehold (net of sales), $80 million for capitalized interest on leasehold and unproved properties, $84 million for seismic, and $16 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 of proved properties, during the quarter Chesapeake's exploration and development costs through the drillbit were $2.00 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 15 of this release.

During the 2008 first quarter, Chesapeake continued the industry's most active drilling program and drilled 478 gross (400 net) operated wells and participated in another 422 gross (48 net) wells operated by other companies. The company's drilling success rate was 100% for company-operated wells and 98% for non-operated wells. Also during the quarter, Chesapeake invested $1.182 billion in operated wells (using an average of 140 operated rigs) and $192 million in non-operated wells (using an average of 93 non-operated rigs).

As of March 31, 2008, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10), were $32.4 billion using field differential adjusted prices of $8.54 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $9.37 per mcf) and $96.37 per bbl (based on a NYMEX quarter-end price of $101.60 per bbl). By comparison, Chesapeake's enterprise value (market equity value plus long-term debt less working capital) as of March 31 was approximately $39.5 billion. Chesapeake's PV-10 changes by approximately $400 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.

By comparison, the December 31, 2007 PV-10 of the company's proved reserves was $20.6 billion ($15 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 March 31, 2007 PV-10 of the company's proved reserves was $20.2 billion using field differential adjusted prices of $7.01 per mcf (based on a NYMEX quarter-end price of $7.34 per mcf) and $60.75 per bbl (based on a NYMEX quarter-end price of $65.85 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, Chesapeake believes the market value of its undeveloped leasehold in just four shale plays - the Fort Worth Barnett, Fayetteville, Haynesville and Marcellus - is approximately $25 billion. Also, the net book value of the company's non-E&P assets (including gathering systems, compressors, land and buildings, investments, long-term derivative instruments and other non-current assets) was $3.6 billion as of March 31, 2008, $3.2 billion as of December 31, 2007 and $2.7 billion as of March 31, 2007.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2008 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $9.05 per mcf and $74.73 per bbl, for a realized natural gas equivalent price of $9.33 per mcfe. Realized gains and losses from natural gas and oil hedging activities during the 2008 first quarter generated a $1.42 gain per mcf and a $19.41 loss per bbl for a 2008 first quarter realized hedging gain of $214 million, or $1.05 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2008 first quarter were a negative $0.40 per mcf and a negative $3.76 per bbl.

By comparison, average prices realized during the 2007 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $9.26 per mcf and $61.13 per bbl, for a realized natural gas equivalent price of $9.33 per mcfe. Realized gains from natural gas and oil hedging activities during the 2007 first quarter generated a $2.95 gain per mcf and an $8.33 gain per bbl for a 2007 first quarter realized hedging gain of $433 million, or $2.82 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing basis differentials to NYMEX during the 2007 first quarter were a negative $0.46 per mcf and a negative $5.36 per bbl.

The following tables compare Chesapeake's open hedge position through swaps and collars as well as gains from lifted hedges as of May 1, 2008 to those previously announced as of March 31, 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 May 1, 2008

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2008 Q2	78%	8.58	70%	75.58
2008 Q3	79%	8.87	75%	76.92
2008 Q4	71%	9.42	67%	79.01
2008 Q2-Q4 Total	76%	8.96	71%	77.16
2009 Total	52%	9.37	70%	82.33
2010 Total	20%	9.56	37%	90.25

Open Natural Gas Collar Positions as of May 1, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q2	6%	8.27	9.92
2008 Q3	5%	8.27	9.92
2008 Q4	4%	8.20	9.91
2008 Q2-Q4 Total	5%	8.25	9.92
2009 Total	5%	8.14	10.82

Gains from Lifted Natural Gas Hedges as of May 1, 2008

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2008 Q2	40	191	0.21

2008 Q3	39	203	0.19
2008 Q4	50	214	0.23
2008 Q2-Q4 Total	129	608	0.21
2009 Total	33	928	0.04

Open Swap Positions as of March 31, 2008

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2008 Q1	76%	8.64	68%	73.97
2008 Q2	75%	8.54	71%	75.58
2008 Q3	71%	8.71	76%	76.92
2008 Q4	64%	9.23	70%	79.01
2008 Total	71%	8.77	71%	76.40
2009 Total	40%	9.13	76%	82.33

Open Natural Gas Collar Positions as of March 31, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q1	10%	7.36	9.28
2008 Q2	5%	8.27	9.91
2008 Q3	4%	8.27	9.91
2008 Q4	3%	8.19	9.88
2008 Total	6%	7.88	9.64
2009 Total	6%	8.22	10.70

Gains from Lifted Natural Gas Hedges as of March 31, 2008

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2008 Q1	156	184	0.85
2008 Q2	41	195	0.21
2008 Q3	38	208	0.18
2008 Q4	47	216	0.22
2008 Total	282	803	0.35
2009 Total	22	934	0.02

Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $5.45 to $6.50 per mcf covering 187 bcf in 2008, $5.45 to $7.25 per mcf covering 332 bcf in 2009 and $5.45 to $7.25 per mcf covering 172 bcf in 2010. Certain open natural gas collar positions include three-way collars that include written put options with strike prices ranging from $5.50 to $6.00 per mcf covering 46 bcf in 2009 and at $6.00 per mcf covering 3.7 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 $65 per bbl covering 3.4 mmbbls in 2008, from $53 to $60 per bbl covering 7.8 mmbbls in 2009 and $60 per bbl covering 4.7 mmbbls in 2010.

The company's updated forecasts for 2008 through 2010 are attached to this release in an Outlook dated May 1, 2008, labeled as Schedule "A," which begins on page 19. This Outlook has been changed from the

Outlook dated March 31, 2008 (attached as Schedule "B," which begins on page 23) to reflect various updated information and include our first forecast for 2010.

Chesapeake's Leasehold and 3-D Seismic Inventories Increase to 13.9 Million Net Acres and 20 Million Acres; Risked Unproved Reserves in the Company's Inventory Reach 37 Tcfe While Unrisked Unproved Reserves Reach 115 Tcfe

Since 2000, Chesapeake has invested $10.3 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (13.9 million net acres) and 3-D seismic (20.0 million acres) in the U.S. On this leasehold, Chesapeake has an estimated 4.0 tcfe of proved undeveloped reserves and approximately 37.2 tcfe of risked unproved reserves (115.5 tcfe of unrisked unproved reserves). The company is currently using 145 operated drilling rigs to further develop its inventory of approximately 33,700 net drillsites, representing more than a 10-year inventory of drilling projects.

Chesapeake categorizes its drilling inventory into two play types: conventional gas resource and unconventional gas resource. In these plays, Chesapeake uses a probability-weighted statistical approach to estimate the potential number of drillsites and unproved reserves associated with such drillsites. The following table summarizes Chesapeake's ownership and activity in each gas resource play type and the following narrative highlights notable projects in the company's drilling inventory.

Play Area	CHK Net Acreage	Est. Drilling Density (Acres)	Est. Risked Net Undrilled Wells	Avg. Reserves Per Well (bcfe)	Total Proved Reserves (bcfe)
Conventional Gas Resource					
Southern Oklahoma	330,000	120	600	2.20	772
South Texas	150,000	80	425	2.00	408
Mountain Front	140,000	320	100	5.00	218
Other Conventional	3,580,000	Various	3,975	Various	2,498
Conventional Sub-total	4,200,000		5,100		3,896
Unconventional Gas Resource					
Fayetteville Shale (Core Area)	585,000	80	5,400	2.20	429
Fort Worth Barnett Shale	260,000	50	3,500	2.50	2,335
Sahara	885,000	70	7,700	0.55	1,100
Colony, Granite & Atoka Washes	310,000	120	1,000	3.25	1,007
Marcellus Shale	1,200,000	160	1,350	2.00	ND
Deep Haley	560,000	320	335	6.00	283
Haynesville Shale	300,000	ND	ND	ND	ND
Other Unconventional	5,600,000	Various	9,315	Various	2,430
Unconventional Sub-total	9,700,000		28,600		7,584
Total	13,900,000		33,700		11,480

	Risked Unproved	Total Proved and Risked Unproved	Unrisked Unproved	Current Daily	Current Operated

Play Area	Reserves (bcfe)	Reserves (bcfe)	Reserves (bcfe)	Production (mmcfe)	Rig Count
Conventional Gas Resource					
Southern Oklahoma	800	1,572	3,100	205	7
South Texas	500	908	2,000	115	6
Mountain Front	300	518	1,100	85	2
Other Conventional	3,200	5,698	17,300	555	15
Conventional Sub-total	4,800	8,696	23,500	960	30
Unconventional Gas Resource					
Fayetteville Shale (Core Area)	9,600	10,029	13,000	130	14
Fort Worth Barnett Shale	5,900	8,235	7,200	430	41
Sahara	3,000	4,100	4,100	190	11
Colony, Granite & Atoka Washes	2,100	3,107	4,000	175	12
Marcellus Shale	1,900	ND	12,800	ND	3
Deep Haley	1,400	1,683	7,400	100	5
Haynesville Shale	ND	ND	ND	ND	4
Other Unconventional	8,500	10,930	43,500	275	25
Unconventional Sub-total	32,400	39,984	92,000	1,300	115
Total	37,200	48,680	115,500	2,260	145

ND = Not disclosed

Fort Worth Barnett Shale (North Texas): The Fort Worth Barnett Shale is 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 first quarter, Chesapeake's average daily net production of 410 mmcfe in the play increased approximately 125% over the 2007 first quarter and 12% over the 2007 fourth quarter. Chesapeake is currently producing approximately 430 mmcfe net per day from the play and anticipates reaching 650 mmcfe net per day by year-end 2008.

The company's proved reserves of 2.3 tcfe in the Fort Worth Barnett Shale play at the end of the 2008 first quarter increased 78% over the 2007 first quarter and 13% over year-end 2007. Chesapeake is currently using 41 operated rigs to further develop its 260,000 net acres of leasehold, of which 225,000 net acres are located in the prime Core and Tier 1 areas. Assuming an additional 3,500 net wells are drilled in the years ahead, the company's estimated risked unproved reserves in the play are 5.9 tcfe (7.2 tcfe of unrisked unproved reserves). The table below highlights operational results over the past five quarters from Chesapeake's operated wells in the Fort Worth Barnett Shale play.

Quarter	Number of Wells Placed on Production	Average Peak Rate (1) (mcfe/d)	Average Lateral Length (feet)
2007 Q1	55	2,594	2,373
2007 Q2	80	3,023	2,594
2007 Q3	106	3,464	2,576
2007 Q4	148	3,462	2,834
2008 Q1	107	3,371	2,897
Total / Weighted Average	496	3,183	2,655

(1) Peak rate defined as the highest production rate of a well over a 24-hour period

Fayetteville Shale (Arkansas): In the Fayetteville Shale, Chesapeake is the second-largest leasehold owner in the Core area of the play. During the 2008 first quarter, Chesapeake's average daily net production of 114 mmcfe in the play increased approximately 700% over the 2007 first quarter and 50% over the 2007 fourth quarter. Chesapeake is currently producing approximately 130 mmcfe net per day from the play and anticipates reaching 200 mmcfe net per day by year-end 2008.

The company's proved reserves of 429 bcfe in the Fayetteville Shale play at the end of the 2008 first quarter increased 380% over the 2007 first quarter and 28% over year-end 2007. Chesapeake is currently using 14 operated rigs to further develop its 585,000 net acres of Core Fayetteville leasehold and anticipates operating up to 23 rigs by year-end 2008. Assuming an additional 5,400 net wells are drilled in the years ahead, the company's estimated risked unproved reserves in the play are 9.6 tcfe (13.0 tcfe of unrisked unproved reserves). The table below highlights operational results over the past five quarters from Chesapeake's operated wells in the Fayetteville Shale play.

Quarter	Number of Wells Placed on Production	Average Peak Rate (1) (mcfe/d)	Average Lateral Length (feet)
2007 Q1	9	1,750	3,105
2007 Q2	13	2,045	2,856
2007 Q3	29	1,863	2,825
2007 Q4	37	1,933	3,011
2008 Q1	36	2,410	3,363
Total / Weighted Average	124	2,053	3,060

(1) Peak rate defined as the highest production rate of a well over a 24-hour period

Haynesville Shale (Ark-La-Tex Region): Chesapeake recently announced a significant discovery in the Haynesville Shale in the Ark-La-Tex region. Based on its geoscientific, petrophysical and engineering research during the past two years, including analysis of over 50 wells drilled through the formation by others in the industry, as well as the results of four horizontal and four vertical wells it has drilled to date, Chesapeake believes the Haynesville Shale play could potentially have a larger impact on the company than any other play in which it has participated. Chesapeake is currently using four operated rigs to further develop its 300,000 net acres of Haynesville Shale leasehold and anticipates operating up to 12 rigs by year-end 2008 and up to 20 rigs by year-end 2009. The company has an aggressive leasehold acquisition effort underway that has added 100,000 net acres during the past five weeks and plans to add an additional 200,000 net acres over time.

Marcellus Shale (West Virginia, Pennsylvania and New York): Chesapeake is the largest leasehold owner in the Marcellus play that spans from West Virginia to southern New York. The company is currently using three operated rigs to further develop its 1.2 million net acres of Marcellus Shale leasehold. Chesapeake is in the beginning phases of significantly ramping up its Marcellus Shale drilling activity and plans to lease at least another 200,000 net acres over time. Assuming 1,350 net wells are drilled in the years ahead, Chesapeake's estimated risked unproved reserves are approximately 1.9 tcfe (12.8 tcfe of unrisked unproved reserves).

Company Agrees to Sell 94 Bcfe of Proved Reserves for Proceeds of $623 Million, or $6.63 per Mcfe, in its Second Volumetric Production Payment Transaction

The company has recently agreed to sell certain Chesapeake-operated long-lived producing assets in Texas, Oklahoma and Kansas in its second volumetric production payment transaction. Chesapeake will sell assets with proved reserves of approximately 94 bcfe and current net production of approximately 47 mmcfe per day for proceeds of $623 million, or $6.63 per mcfe. Chesapeake will retain drilling rights on the properties below currently producing intervals. For accounting purposes, the transaction will be treated as a sale and the company's proved reserves will be reduced accordingly. The transaction is expected to close today. Chesapeake also plans to pursue occasional undeveloped leasehold sales to high-grade its inventory and further monetizations of mature producing properties as needs and opportunities arise.

Company Announces Plans to Sell Remaining Arkoma Basin Woodford Shale Properties for Anticipated Proceeds of Over $1.5 Billion

As part of high-grading its leasehold inventory and in order to redeploy capital to higher priority areas in the company's operations, Chesapeake has announced its intention to sell all of its remaining Arkoma Basin Woodford Shale properties in Hughes, Pittsburg, Coal and Atoka counties in Oklahoma. The properties consist of approximately 85,000 net acres, 40 mmcfe per day of current production and over

2.0 tcfe of potential net reserves. The company expects to receive proceeds of over $1.5 billion from the sale of the properties and anticipates completing a transaction in mid-2008. Chesapeake has retained Meagher Oil & Gas Properties, Inc. to assist in the sale of the properties.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report our financial and operational results for the 2008 first quarter. We are especially proud of our 31% increase in average daily production in the 2008 first quarter compared to the 2007 first quarter and by our adjusted net income per share increasing by 25% to an all-time record level. This is strong evidence that our rapid production growth is translating into proportional gains in per-share net income despite inflationary pressure on the industry's cost structure. By investing early in new plays and through our strong technical skills and aggressive cost control measures, we have been able to deliver substantial per-share value to shareholders.

"We are also pleased with our growth in proved reserves and believe that we are on track to reach 13 tcfe of proved reserves by year-end 2008 and 15 tcfe by year-end 2009. In addition, our new Haynesville Shale play continues to look very promising and our acreage acquisition efforts there remain successful. We now own or have commitments for over 300,000 net acres and maintain our goal of reaching 500,000 net acres in the play over time. During the past month, we brought on-line our fourth horizontal Haynesville Shale well and it provides further support for our assessment of the play.

"Finally, our Barnett Shale, Fayetteville Shale and Marcellus Shale plays continue to look very attractive and increasingly more valuable. We now own approximately 260,000 net acres in the Barnett Shale play, 585,000 net acres in the Core area of the Fayetteville Shale play and 1.2 million net acres in the Marcellus Shale play. Based on recent industry transactions and peer company valuations, we believe the undeveloped acreage of these three plays, together with our 300,000 net acres in the Haynesville Shale play, is worth more than $25 billion. When added to the $32 billion of PV-10 of the company's proved reserves, Chesapeake's assets now appear to be worth at least $57 billion, without even considering the substantial value of the company's non-shale leasehold and other non E&P assets. We are excited about our progress and momentum to date, but are even more enthusiastic about our company's ability in the future to produce growing amounts of clean, affordable, abundant and American natural gas to our customers and to deliver substantial value from our continuing growth to our shareholders."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, May 2, 2008, at 11:00 a.m. EDT. The telephone number to access the conference call is 913-312-1419 or toll-free 800-776-0420. The passcode for the call is 2125846. We encourage those who would like to participate in the call to dial the access number between 10:50 and 11:00 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from 2 p.m. EDT on May 2, 2008, and will run through midnight EDT on Friday, May 16, 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 2125846. 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, projections of 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 Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the U.S. Securities and Exchange Commission on February 29, 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.

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 term "unproved" to describe volumes of 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 third-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, Fayetteville Shale, Haynesville Shale, Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. Chesapeake's Internet address is www.chk.com.

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

THREE MONTHS ENDED:	March 31, 2008 $	March 31, 2008 $/mcfe	March 31, 2007 $	March 31, 2007 $/mcfe
REVENUES:				
Natural gas and oil sales	773	3.78	1,125	7.31
Natural gas and oil marketing sales	796	3.90	422	2.75
Service operations revenue	42	0.21	33	0.22
Total Revenues	1,611	7.89	1,580	10.28
OPERATING COSTS:				
Production expenses	201	0.98	142	0.93
Production taxes	75	0.37	42	0.27
General and administrative expenses	79	0.39	52	0.34
Natural gas and oil marketing expenses	774	3.79	407	2.65
Service operations expense	35	0.17	22	0.14
Natural gas and oil depreciation, depletion and amortization	515	2.52	393	2.56
Depreciation and amortization of other				

assets	36	0.18	36	0.23
Total Operating Costs	1,715	8.40	1,094	7.12
INCOME (LOSS) FROM OPERATIONS	(104)	(0.51)	486	3.16
OTHER INCOME (EXPENSE):				
Interest and other income	(9)	(0.04)	9	0.06
Interest expense	(101)	(0.50)	(79)	(0.51)
Total Other Income (Expense)	(110)	(0.54)	(70)	(0.45)
INCOME (LOSS) BEFORE INCOME TAXES	(214)	(1.05)	416	2.71
Income Tax Expense (Benefit):				
Current	--	--	--	--
Deferred	(82)	(0.40)	158	1.03
Total Income Tax Expense (Benefit)	(82)	(0.40)	158	1.03
NET INCOME (LOSS)	(132)	(0.65)	258	1.68
Preferred stock dividends	(11)	(0.05)	(26)	(0.17)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	(143)	(0.70)	232	1.51
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ (0.29)		$ 0.51	
Assuming dilution	$ (0.29)		$ 0.50	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	493		451	
Assuming dilution	493		516	

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

	March 31, 2008	December 31, 2007
Cash	$ 1	$ 1

Other current assets	1,945	1,395
Total Current Assets	1,946	1,396
Property and equipment (net)	30,519	28,337
Other assets	997	1,001
Total Assets	$ 33,462	$ 30,734
Current liabilities	$ 4,220	$ 2,761
Long-term debt, net	12,250	10,950
Asset retirement obligation	243	236
Other long-term liabilities	1,203	691
Deferred tax liability	4,076	3,966
Total Liabilities	21,992	18,604
Stockholders' Equity	11,470	12,130
Total Liabilities & Stockholders' Equity	$ 33,462	$ 30,734
Common Shares Outstanding (in millions)	514	511

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

	March 31, 2008	% of Total Book Capitalization	December 31, 2007	% of Total Book Capitalization
Long-term debt, net	$ 12,250	52%	$ 10,950	47%
Stockholders' equity	11,470	48%	12,130	53%
Total	$ 23,720	100%	$ 23,080	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	$ 1,374	686(a)	2.00
Acquisition of proved properties	63	39	1.59
Sale of proved properties	(86)	(32)	(2.72)
Drilling and net acquisition cost	1,351	693	1.95
Revisions - price	--	112	--

Acquisition of unproved properties and leasehold	853	--	--
Sale of unproved properties and leasehold	(159)	--	--
Net leasehold and unproved property acquisition	694	--	--
Capitalized interest on leasehold and unproved property	80	--	--
Geological and geophysical costs	84	--	--
Geologic, geophysical and capitalized interest	164	--	--
Subtotal	2,209	805	2.74
Tax basis step-up	13	--	--
Asset retirement obligation and other	3	--	--
Total	$ 2,225	805	2.76

(a) Includes 365 bcfe of positive performance revisions (342 bcfe relating to infill drilling and increased density locations and 23 bcfe of other performance related revisions) and excludes positive revisions of 112 bcfe resulting from natural gas and oil price increases between December 31, 2007, and March 31, 2008.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
THREE MONTHS ENDED MARCH 31, 2008
(unaudited)

	Bcfe
Beginning balance, 01/01/08	10,879
Extensions and discoveries	321
Acquisitions	39
Divestitures	(32)
Revisions - performance	365
Revisions - price	112
Production	(204)
Ending balance, 3/31/08	11,480
Reserve replacement	805
Reserve replacement ratio (a)	395%

(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
March 31,

	2008	2007
Natural Gas and Oil Sales ($ in millions):		
Natural gas sales	$ 1,432	$ 888
Natural gas derivatives - realized gains (losses)	268	415
Natural gas derivatives - unrealized gains (losses)	(1,002)	(297)
Total Natural Gas Sales	698	1,006
Oil sales	258	113
Oil derivatives - realized gains (losses)	(53)	18
Oil derivatives - unrealized gains (losses)	(130)	(12)
Total Oil Sales	75	119
Total Natural Gas and Oil Sales	$ 773	$ 1,125
Average Sales Price - excluding gains (losses) on derivatives:		
Natural gas ($ per mcf)	$ 7.63	$ 6.31
Oil ($ per bbl)	$ 94.14	$ 52.80
Natural gas equivalent ($ per mcfe)	$ 8.28	$ 6.52
Average Sales Price - excluding unrealized gains (losses) on derivatives):		
Natural gas ($ per mcf)	$ 9.05	$ 9.26
Oil ($ per bbl)	$ 74.73	$ 61.13
Natural gas equivalent ($ per mcfe)	$ 9.33	$ 9.33
Interest Expense ($ in millions):		
Interest	$ 88	$ 76
Derivatives - realized (gains) losses	--	2
Derivatives - unrealized (gains) losses	13	1
Total Interest Expense	$ 101	$ 79

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

THREE MONTHS ENDED:	March 31, 2008	March 31, 2007
Beginning cash	$ 1	$ 3
Cash provided by operating activities	1,498	977
Cash (used in) investing activities	(2,675)	(1,869)
Cash provided by financing activities	1,177	893
Ending cash	1	4

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

THREE MONTHS ENDED:	March 31, 2008	December 31, 2007	March 31, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,498	$ 1,544	$ 977
Adjustments:			
Changes in assets and liabilities	14	(222)	147
OPERATING CASH FLOW(a)	$ 1,512	$ 1,322	$ 1,124

(a) Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of a natural gas and oil company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies within the natural gas and oil exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing, or financing activities as an indicator of cash flows, or as a measure of liquidity.

THREE MONTHS ENDED:	March 31, 2008	December 31, 2007	March 31, 2007
NET INCOME (LOSS)	$ (132)	$ 303	$ 258
Income tax expense (benefit)	(82)	186	158
Interest expense	101	128	79
Depreciation and amortization of other assets	36	33	36
Natural gas and oil depreciation, depletion and amortization	515	521	393
EBITDA(b)	$ 438	$ 1,171	$ 924

(b) Ebitda represents net income (loss) before income tax expense, interest expense, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit 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:	March 31, 2008	December 31, 2007	March 31, 2007
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,498	$ 1,544	$ 977
Changes in assets and liabilities	14	(222)	147
Interest expense	101	128	79
Unrealized gains (losses) on natural gas and oil derivatives	(1,132)	(261)	(310)
Other non-cash items	(43)	(18)	31

EBITDA	$ 438	$ 1,171	$ 924

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

THREE MONTHS ENDED:	March 31, 2008	December 31, 2007	March 31, 2007
Net income (loss) available to common shareholders	$ (143)	$ 158	$ 232
Adjustments:			
Unrealized (gains) losses on derivatives, net of tax	704	180	193
Loss on conversion/exchange of preferred stock	--	128	--
Adjusted net income available to common shareholders(1)	561	466	425
Preferred stock dividends	11	17	26
Total adjusted net income	$ 572	$ 483	$ 451
Weighted average fully diluted shares outstanding(2)	524	520	516
Adjusted earnings per share assuming dilution	$ 1.09	$ 0.93	$ 0.87

(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:	March 31, 2008	December 31, 2007	March 31, 2007
EBITDA	$ 438	$ 1,171	$ 924

Adjustments, before tax:			
Unrealized (gains) losses on natural gas and oil derivatives	1,132	261	310
Adjusted ebitda(1)	$ 1,570	$ 1,432	$ 1,234

(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 MAY 1, 2008

Quarter Ending June 30, 2008 and Years Ending December 31, 2008, 2009 and 2010.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of May 1, 2008, we are using the following key assumptions in our projections for the second quarter of 2008 and the full years 2008, 2009 and 2010.

The primary changes from our March 31, 2008 Outlook are in italicized bold and are explained as follows:

1) Our first guidance for the 2008 second quarter and the full year 2010 has been provided;

2) Production guidance has been updated for full years 2008 and 2009;

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

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

5) Shares outstanding have been updated to reflect the exercise of the over-allotment option in our recent common stock offering and to incorporate the effects of our contingently convertible notes.

	Quarter Ending 6/30/2008	Year Ending 12/31/2008
Estimated Production(a)		
Natural gas - bcf	190 - 192	791 - 801
Oil - mbbls	2,700	11,000
Natural gas equivalent - bcfe	206 - 208	857 - 867
Daily natural gas equivalent midpoint - mmcfe	2,275	2,360
Year-over-year production increase	22%	21%
NYMEX Prices (b) (for calculation of realized hedging effects only):		
Natural gas - $/mcf	$8.53	$8.14
Oil - $/bbl	$80.00	$84.48
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	$0.50	$1.17
Oil - $/bbl	$(4.66)	$(7.47)
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	10 - 14%	10 - 14%
Oil - $/bbl	7 - 9%	7 - 9%
Operating Costs per Mcfe of Projected Production:		

Production expense	$0.95 - 1.05	$0.95 - 1.05
Production taxes (about 5% of O&G revenues) (c)	$0.35 - 0.40	$0.35 - 0.40
General and administrative(d)	$0.33 - 0.37	$0.33 - 0.37
Stock-based compensation (non-cash)	$0.08 - 0.10	$0.10 - 0.12
DD&A of natural gas and oil assets	$2.50 - 2.70	$2.50 - 2.70
Depreciation of other assets	$0.20 - 0.24	$0.20 - 0.24
Interest expense(e)	$0.50 - 0.55	$0.50 - 0.55
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	38.5%	38.5%
Equivalent Shares Outstanding - in millions:		
Basic	519	514
Diluted	556	550
Budgeted E&P Capital Expenditures, net - in millions:		
Drilling	$1,300 - 1,500	$5,500 - 6,000
Acquisition of leasehold and producing properties	$600 - 800	$2,100 - 2,600
Sale of leasehold and producing properties(a)	$(625)	$(2,975 - 3,225)
Geological and geophysical costs	$75	$300
Total budgeted E&P capital expenditures, net	$1,350 - 1,750	$4,925 - $5,675

	Year Ending 12/31/2009	Year Ending 12/31/2010
Estimated Production(a)		
Natural gas - bcf	918 - 938	1,052 - 1,092
Oil - mbbls	12,000	13,000
Natural gas equivalent - bcfe	990 - 1,010	1,130 -1,170
Daily natural gas equivalent midpoint - mmcfe	2,740	3,150
Year-over-year production increase	16%	15%
NYMEX Prices (b) (for calculation of realized hedging effects only):		
Natural gas - $/mcf	$8.00	$8.00
Oil - $/bbl	$80.00	$80.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Natural gas - $/mcf	$0.93	$0.40
Oil - $/bbl	$1.78	$4.34
Estimated Differentials to NYMEX Prices:		
Natural gas - $/mcf	10 - 14%	10 - 14%
Oil - $/bbl	7 - 9%	7 - 9%
Operating Costs per Mcfe of Projected Production:		
Production expense	$1.00 - 1.10	$1.05 - 1.15
Production taxes (about 5% of O&G revenues) (c)	$0.35 - 0.40	$0.35 - 0.40
General and administrative(d)	$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	$2.50 - 2.70	$2.50 - 2.70
Depreciation of other assets	$0.20 - 0.24	$0.20 - 0.24

Interest expense(e)	$0.50 - 0.55	$0.50 - 0.55
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	38.5%	38.5%
Equivalent Shares Outstanding - in millions:		
Basic	529	541
Diluted	564	572
Budgeted E&P Capital Expenditures, net - in millions:		
Drilling	$5,750 - 6,250	$6,000 - 6,500
Acquisition of leasehold and producing properties	$1,500 - 2,000	$1,500 -2,000
Sale of leasehold and producing properties(a)	$(1,000 - 1,500)	$(1,000 - 1,500)
Geological and geophysical costs	$300	$300
Total budgeted E&P capital expenditures, net	$6,550 - $7,050	$6,800 - $7,300

(a) The 2008 and 2009 forecasts assume that the company sells: 1) producing properties for $625 million in the 2008 second quarter in a volumetric production payment (VPP) transaction; 2) Arkoma Basin properties for $1.50 - 1.75 billion in the 2008 third quarter; 3) undeveloped leasehold or producing properties for $600 million in the 2008 second half; and 4) undeveloped leasehold or producing properties for $1.0-1.5 billion in each of 2009 and 2010.

(b) NYMEX oil prices have been updated for actual contract prices through March 2008 and NYMEX natural gas prices have been updated for actual contract prices through April 2008.

(c) Severance tax per mcfe is based on NYMEX prices of: $80.00 per bbl of oil and $7.40 to $8.70 per mcf of natural gas during Q2 2008; $84.48 per bbl of oil and $7.60 to $8.90 per mcf of natural gas during calendar 2008; and $80.00 per bbl of oil and $7.80 to $9.10 per mcf of natural gas during calendar 2009 and 2010.

(d) Excludes expenses associated with non-cash stock compensation.

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

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 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 from Lifted Swaps ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q2 2008	139.4	$8.66	191	73%	$40.2	$0.21
Q3 2008	150.0	$8.97	203	74%	$39.3	$0.19
Q4 2008	142.6	$9.53	214	67%	$50.2	$0.23
Q2-Q4 2008(1)	432.0	$9.05	608	71%	$129.7	$0.21
Total 2009(1)	467.6	$9.44	928	50%	$32.6	$0.04
Total 2010(1)	214.5	$9.56	1,072	20%	$(4.2)	$0.00

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.45 to $6.50 covering 187 bcf in 2008, 5.45 to $7.25

covering 332 bcf in 2009 and $5.45 to $7.25 covering 172 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
Q2 2008	10.9	$8.27	$9.92	191	6%
Q3 2008	11.0	$8.27	$9.92	203	5%
Q4 2008	9.2	$8.20	$9.91	214	4%
Q2-Q4 2008	31.1	$8.25	$9.92	608	5%
Total 2009(1)	45.7	$8.14	$10.82	928	5%
Total 2010(1)	3.7	$7.30	$12.00	1,072	0%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.50 to $6.00 covering 46 bcf in 2009 and at $6.00 covering 4 bcf in 2010.

Note: Not shown above are written call options covering 128 bcf of production in 2008 at a weighed average price of $10.16 for a weighted average premium of $0.68, 178 bcf of production in 2009 at a weighed average price of $11.29 for a weighted average premium of $0.50 and 161 bcf of production in 2010 at a weighed average price of $10.71 for a weighted average premium of $0.60.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(a):	Volume in Bcf's	NYMEX plus(a):
2008	132.4	0.36	23.0	0.33
2009	91.1	0.33	16.9	0.28
2010	--	--	10.2	0.26
2011	--	--	12.1	0.25
2012	10.7	0.34	--	--
Totals	234.2	$ 0.35	62.2	$ 0.29

(a) 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 ($128 million as of March 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)	Open Swap Positions Assuming Natural Gas Production in Bcf's of:	as a % of Estimated Total Natural Gas Production
Q2 2008	9.6	$4.68	$7.41	($2.73)	191	5%
Q3 2008	9.7	$4.68	$7.41	($2.74)	203	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	214	5%
Q2-Q4 2008	29.0	$4.67	$7.55	($2.88)	608	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	928	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	Open Swap Positions Assuming Oil Production in mbbls of:	Total Positions as a % of Estimated Total Oil Production	Total Losses from Lifted Swaps ($ millions)	Lifted Losses per bbl of Estimated Total Oil Production
Q2 2008	1,896	75.58	2,700	70%	$(4.7)	$(1.75)
Q3 2008	2,039	76.92	2,730	75%	$(4.6)	$(1.69)
Q4 2008	1,886	79.01	2,825	67%	$(4.7)	$(1.68)
Q2-Q4 2008(1)	5,821	$77.16	8,255	71%	$(14.0)	$(1.70)
Total 2009(1)	8,395	$82.33	12,000	70%	--	--
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 $65.00 covering 3,423 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 2,109 mbbls of production in 2008 at a weighted average price of $82.82 for a weighted average premium of $3.17, 2,555 mbbls of production in 2009 at a weighed average price of $82.14 for a weighted average premium of $4.98 and 2,555 mbbls of production in 2010 at a weighed average price of $96.43 for a weighted average premium of $3.79.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF MARCH 31, 2008

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF MAY 1, 2008

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

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of March 31, 2008, we are using the following key assumptions in our projections for the first quarter of 2008 and the full-years 2008 and 2009.

The primary changes from our February 21, 2008 Outlook are in italicized bold and are explained as follows:

1) We are increasing our prior production guidance for the full-years 2008 and 2009 (note: guidance in this Outlook excludes production expected to be sold in conjunction with various anticipated monetizations transactions in 2008 and 2009);

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

3) Budgeted capital expenditure assumptions have been updated; and

4) Share assumptions have been updated to reflect our recent 20 million share common stock offering.

	Quarter Ending 3/31/2008	Year Ending 12/31/2008	Year Ending 12/31/2009
Estimated Production(a)			
Oil - mbbls	2,675	10,700	11,000
Natural gas - bcf	182 - 186	798 - 808	924 - 944
Natural gas equivalent - bcfe	198 - 202	862.5 - 872.5	990 - 1,010
Daily natural gas equivalent midpoint - mmcfe	2,200	2,370	2,740
NYMEX Prices (b) (for calculation of realized hedging effects only):			
Oil - $/bbl	$80.98	$82.36	$80.00
Natural gas - $/mcf	$7.55	$8.01	$8.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	$(6.98)	$(5.94)	$1.94
Natural gas - $/mcf	$1.84	$1.11	$0.69
Estimated Differentials to NYMEX Prices:			
Oil - $/bbl	7 - 9%	7 - 9%	7 - 9%
Natural gas - $/mcf	10 - 14%	10 - 14%	10 - 14%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.90 - 1.00	$0.90 - 1.00	$0.90 - 1.00
Production taxes (generally 5% of O&G revenues) (c)	$0.32 - 0.37	$0.32 - 0.37	$0.32 - 0.37
General and administrative(d)	$0.33 - 0.37	$0.33 - 0.37	$0.33 - 0.37
Stock-based compensation (non-cash)	$0.08 - 0.10	$0.10 - 0.12	$0.10 - 0.12
DD&A of oil and natural gas assets	$2.50 - 2.70	$2.50 - 2.70	$2.50 - 2.70
Depreciation of			

other assets	$0.20 - 0.24	$0.20 - 0.24	$0.20 - 0.24
Interest expense(e)	$0.50 - 0.55	$0.50 - 0.55	$0.50 - 0.55
Other Income per Mcfe:			
Oil and natural gas 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 (About Equals 97% deferred)	38.5%	38.5%	38.5%
Equivalent Shares Outstanding - in millions:			
Basic	493	509	523
Diluted	525	540	553
Budgeted Capital Expenditures, net - in millions:			
Drilling	$1,100 - 1,200	$4,600 - 5,000	$5,000 - 5,400
Leasehold and property acquisition costs	$400 - 450	$1,300 - 1,500	$1,300 - 1,500
Monetization of oil and gas properties(a)	--	$(1,000)	$(1,000)
Geological and geophysical costs	$75	$250	$250
Total budgeted capital expenditures, net	$1,575 - 1,725	$5,150 - $5,750	$5,550 - $6,150

(a) The 2008 and 2009 forecasts assume that the company monetizes $2 billion of producing properties in multiple transactions in the second and fourth quarters of 2008 and 2009.

(b) NYMEX oil prices have been updated for actual contract prices through February 2008 and NYMEX natural gas prices have been updated for actual contract prices through March 2008.

(c) Severance tax per mcfe is based on NYMEX prices of: $80.98 per bbl of oil and $7.00 to $8.00 per mcf of natural gas during Q1 2008; $82.36 per bbl of oil and $7.20 to $8.20 per mcf of natural gas during calendar 2008; and $80.00 per bbl of oil and $7.30 to $8.30 per mcf of natural gas during calendar 2009.

(d) Excludes expenses associated with non-cash stock compensation.

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

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future oil and natural gas 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) 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.

(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 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.

(v) 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.

(vi) 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.

(vii) 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.

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 oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to oil and natural gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 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 from Lifted Swaps ($ millions)	Total Lifted Gain per Mcf of Estimated Total Natural Gas Production
Q1 2008	131.0	$8.59	184	71%	$156.4	$0.85
Q2 2008	137.5	$8.62	195	71%	$40.6	$0.21
Q3 2008	138.0	$8.80	208	66%	$38.1	$0.18
Q4 2008	127.6	$9.34	216	59%	$47.1	$0.22
Total 2008(1)	534.1	$8.83	803	67%	$282.2	$0.35
Total 2009(1)	356.1	$9.22	934	38%	$22.1	$0.02

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.45 to $6.50 covering 190 bcf in 2008 and $5.45 to

$6.50 covering 280 bcf in 2009.

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 2008	18.5	$7.36	$9.28	184	10%
Q2 2008	9.1	$8.27	$9.91	195	5%
Q3 2008	9.2	$8.27	$9.91	208	4%
Q4 2008	7.4	$8.19	$9.88	216	3%
Total 2008(1)	44.2	$7.88	$9.64	803	6%
Total 2009(1)	56.7	$8.22	$10.70	934	6%

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 11 bcf in 2008 and $5.50 to $6.00 covering 46 bcf in 2009.

Note: Not shown above are written call options covering 111 bcf of production in 2008 at a weighed average price of $10.26 for a weighted average premium of $0.66 and 191 bcf of production in 2009 at a weighed average price of $11.24 for a weighted average premium of $0.52.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(a):	Volume in Bcf's	NYMEX plus(a):
2008	132.4	0.36	23.0	0.33
2009	91.1	0.33	16.9	0.28
2010	--	--	10.2	0.26
2011	--	--	12.1	0.25
2012	10.7	0.34	--	--
Totals	234.2	$ 0.35	62.2	$ 0.29

(a) 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 ($173 million as of December 31, 2007). 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 oil and natural gas 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 oil and natural gas 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 oil and natural gas 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 2008	9.5	$4.68	$9.42	($4.74)	184	5%
Q2 2008	9.5	$4.68	$7.41	($2.73)	195	5%
Q3 2008	9.7	$4.68	$7.41	($2.74)	208	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	216	4%
Total 2008	38.4	$4.68	$8.02	($3.34)	803	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	934	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
Q1 2008	1,823	73.97	2,675	68%	$(3.2)	$(1.21)
Q2 2008	1,896	75.58	2,665	71%	$(4.7)	$(1.77)
Q3 2008	2,039	76.92	2,680	76%	$(4.6)	$(1.72)
Q4 2008	1,886.	79.01	2,680	70%	$(4.7)	$(1.77)
Total 2008(1)	7,644	$76.40	10,700	71%	$(17.2)	$(1.62)
Total 2009(1)	8,395	$82.33	11,000	76%	--	--

(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 4,304 mbbls in 2008 and from $52.50 to $60.00 covering 7,848 mbbls in 2009.

Note: Not shown above are written call options covering 2,564 mbbls of production in 2008 at a weighted average price of $82.50 for a weighted average premium of $3.17 and 2,555 mbbls of production in 2009 at a weighed average price of $82.14 for a weighted average premium of $4.98.

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http://investors.chk.com/2008-05-01-chesapeake-energy-corporation-reports-financial-and-operational-results-for-the-2008-first-quarter