NEWS
RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2007 Fourth Quarter and Full Year

Company Reports 2007 Fourth Quarter Net Income Available to Common Shareholders of $158 Million, or $0.33 per Fully Diluted Common Share, on Revenue of $2.1 Billion; Adjusted Net Income Available to Common Shareholders Reaches $466 Million, or $0.93 per Fully Diluted Common Share Full Year 2007 Net Income Available to Common Shareholders Reaches $1.2 Billion, or $2.62 per Fully Diluted Common Share, on Revenue of $7.8 Billion; Adjusted Net Income Available to Common Shareholders Reaches $1.6 Billion, or $3.21 per Fully Diluted Common Share Fourth Quarter 2007 Production of 2.2 Bcfe per Day Increases 10% Sequentially and 34% Year-Over-Year; Full Year Production of 2.0 Bcfe per Day Increases 23% Year-Over-Year Proved Reserves Reach Record Level of 10.9 Tcfe and Increase 21% Year-Over-Year; Company Delivers Full Year Reserve Replacement Rate of 369% from 1.9 Tcfe of Additions at a Drilling and Acquisition Cost of $2.08 per Mcfe

OKLAHOMA CITY--(BUSINESS WIRE)--Feb. 21, 2008--Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operating results for the 2007 fourth quarter and full year. For the 2007 fourth quarter, Chesapeake generated net income available to common shareholders of $158 million ($0.33 per fully diluted common share), operating cash flow of $1.3 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.2 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $2.1 billion and production of 204 billion cubic feet of natural gas equivalent (bcfe).

For the 2007 full year, Chesapeake generated net income available to common shareholders of $1.2 billion ($2.62 per fully diluted common share), operating cash flow of $4.6 billion and ebitda of $4.7 billion on revenue of $7.8 billion and production of 714 bcfe.

The company's 2007 fourth quarter and full year net income available to common shareholders and ebitda 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 in the 2007 fourth quarter of $466 million ($0.93 per fully diluted common share) and adjusted ebitda of $1.4 billion. For the 2007 full year, Chesapeake generated adjusted net income to common shareholders of $1.6 billion ($3.21 per fully diluted common share) and adjusted ebitda of $5.0 billion.

The excluded items and their effects on 2007 fourth quarter and full year reported results are detailed as follows:

-- an unrealized after-tax mark-to-market loss of $180 million in the fourth quarter and $257 million for the full year resulting from the company's oil and natural gas and interest rate hedging programs;

-- an after-tax gain of $51 million in the second quarter resulting from the sale of the company's investment in Eagle Energy Partners I, L.P.; and

-- a reduction of net income available to common shareholders of $128 million for the fourth quarter and full year 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 18-21 of this release.

Key Operational and Financial Statistics Summarized Below for the 2007 Fourth Quarter, 2007 Third Quarter, 2006 Fourth Quarter and for the Full Years 2007 and 2006

The table below summarizes Chesapeake's key results during the 2007 fourth quarter and compares them to the 2007 third quarter and the 2006 fourth quarter and also compares the 2007 full year to the 2006 full year.

	Three Months Ended:			Full Year Ended:	
	12/31/07	9/30/07	12/31/06	12/31/07	12/31/06
Average daily production (in mmcfe)	2,219	2,026	1,653	1,957	1,585
Natural gas as % of total production	92	91	91	92	91
Natural gas production (in bcf)	187.8	170.3	138.8	655.0	526.5
Average realized natural gas price ($/mcf) (a)	8.11	7.41	9.03	8.14	8.76
Oil production (in mbbls)	2,735	2,680	2,217	9,882	8,654
Average realized oil price ($/bbl) (a)	72.58	69.25	59.95	67.50	59.14
Natural gas equivalent production (in bcfe)	204.2	186.4	152.1	714.3	578.4
Natural gas equivalent realized price ($/mcfe) (a)	8.43	7.76	9.11	8.40	8.86
Oil and natural gas marketing income ($/mcfe)	.09	.10	.11	.10	.09
Service operations income ($/mcfe)	.04	.06	.09	.06	.11
Production expenses ($/mcfe)	(.88)	(.89)	(.82)	(.90)	(.85)
Production taxes ($/mcfe)	(.32)	(.30)	(.31)	(.30)	(.31)
General and administrative costs ($/mcfe) (b)	(.29)	(.23)	(.22)	(.26)	(.19)
Stock-based compensation ($/mcfe)	(.08)	(.10)	(.04)	(.08)	(.05)
DD&A of oil and natural gas properties ($/mcfe)	(2.55)	(2.57)	(2.51)	(2.57)	(2.35)
D&A of other assets ($/mcfe)	(.16)	(.24)	(.20)	(.22)	(.18)
Interest expense ($/mcfe) (a)	(.49)	(.52)	(.54)	(.51)	(.52)
Operating cash flow ($ in millions) (c)	1,322	1,085	1,095	4,607	4,045
Operating cash flow ($/mcfe)	6.48	5.82	7.20	6.45	6.99
Adjusted ebitda ($ in millions) (d)	1,432	1,195	1,210	5,028	4,449
Adjusted ebitda ($/mcfe)	7.01	6.41	7.96	7.04	7.69
Net income to common shareholders ($ in millions)	158	346	446	1,229	1,904
Earnings per share - assuming dilution					

($)	.33	.72	.96	2.62	4.35
Adjusted net income to common shareholders ($ in millions) (e)	466	330	418	1,563	1,575
Adjusted earnings per share - assuming dilution ($)	.93	.69	.90	3.21	3.61

(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 before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on pages 20-21

(e) defined as net income available to common shareholders, as adjusted to remove the effects of certain items detailed on pages 20-21

Average Realized Prices, Hedging Results and Hedging Positions Detailed

Average prices realized during the 2007 fourth quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $8.11 per thousand cubic feet of natural gas (mcf) and $72.58 per barrel of oil and natural gas liquids (bbl), for a realized natural gas equivalent price of $8.43 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains and losses from oil and natural gas 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 differentials to NYMEX during the 2007 fourth quarter were a negative $0.59 per mcf and a negative $4.44 per bbl.

By comparison, average prices realized during the 2006 fourth quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $9.03 per mcf and $59.95 per bbl, for a realized natural gas equivalent price of $9.11 per mcfe. Realized gains from oil and natural gas hedging activities during the 2006 fourth quarter generated a $3.14 gain per mcf and a $4.88 gain per bbl for a 2006 fourth quarter realized hedging gain of $447 million, or $2.94 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing differentials to NYMEX during the 2006 fourth quarter were a negative $0.67 per mcf and a negative $5.14 per bbl.

For the 2007 full year, average prices realized (including realized gains or losses from oil and natural gas 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 and losses from oil and natural gas 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 differentials to NYMEX during the 2007 full year were a negative $0.57 per mcf and a negative $3.67 per bbl. During 2006 and 2007, Chesapeake's oil and natural gas hedging activities generated a total realized gain of $2.5 billion.

By comparison, for the 2006 full year, average prices realized (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $8.76 per mcf and $59.14 per bbl, for a realized natural gas equivalent price of $8.86 per mcfe. Realized gains and losses from oil and natural gas hedging activities during the 2006 full year generated a $2.41 gain per mcf and a $1.72 loss per bbl for a 2006 full year realized hedging gain of $1.3 billion, or $2.17 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing differentials to NYMEX during the 2006 full year were a negative $0.89 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 February 21, 2008 to those previously announced as of November 6, 2007. Depending on changes in oil and natural gas futures markets and management's view of underlying oil and natural gas 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 21, 2008

Quarter or Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2008 Q1	76%	8.64	68%	73.97
2008 Q2	73%	8.44	72%	75.22
2008 Q3	69%	8.60	72%	75.11
2008 Q4	61%	9.13	65%	76.79
2008 Total	70%	8.69	69%	75.24
2009 Total	33%	8.94	73%	81.60

Open Natural Gas Collar Positions as of February 21, 2008

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX
2008 Q1	10%	7.36	9.28
2008 Q2	1%	7.50	9.68
2008 Q3	1%	7.50	9.68
2008 Q4	1%	7.50	9.68
2008 Total	3%	7.41	9.40
2009 Total	5%	8.14	10.82

Gains from Lifted Natural Gas Hedges as of February 21, 2008

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2008 Q1	156	184	0.85
2008 Q2	45	194	0.23
2008 Q3	41	205	0.20
2008 Q4	45	210	0.22
2008 Total	287	793	0.36
2009 Total	13	897	0.01

Open Swap Positions as of November 6, 2007

Quarter or Year	Natural Gas % Hedged	Natural Gas $ NYMEX	Oil % Hedged	Oil $ NYMEX
2008 Q1	74%	8.78	80%	72.84
2008 Q2	69%	8.49	78%	72.59
2008 Q3	67%	8.64	75%	72.44
2008 Q4	61%	9.16	66%	73.48
2008 Total	68%	8.76	75%	72.82
2009 Total	28%	8.87	73%	78.81

Open Natural Gas Collar Positions as of November 6, 2007

Quarter or Year	% Hedged	Average Floor $ NYMEX	Average Ceiling $ NYMEX

2008 Q1	10%	7.36	9.28
2008 Q2	1%	7.50	9.68
2008 Q3	1%	7.50	9.68
2008 Q4	1%	7.50	9.68
2008 Total	3%	7.41	9.40
2009 Total	3%	7.97	11.18

Gains from Lifted Natural Gas Hedges as of November 6, 2007

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2008 Q1	133	188	0.71
2008 Q2	39	194	0.20
2008 Q3	36	202	0.18
2008 Q4	37	209	0.18
2008 Total	245	793	0.31
2009 Total	13	897	0.01

Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $5.45 to $6.50 covering 191 billion cubic feet of natural gas (bcf) in 2008 and $5.45 to $6.50 covering 214 bcf in 2009. 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 covering 11 bcf in 2008 and $5.50 to $6.00 covering 46 bcf in 2009. Also, certain open oil swap positions include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $65.00 covering four million barrels of oil and natural gas liquids (mmbbls) in 2008 and from $52.50 to $60.00 covering seven mmbbls in 2009.

The company's updated forecasts for 2008 through 2009 are attached to this release in an Outlook dated February 21, 2008 labeled as Schedule "A", which begins on page 23. This Outlook has been changed from the Outlook dated November 6, 2007 (attached as Schedule "B", which begins on page 27) to reflect various updated information.

Company Provides Update on 2008-2009 Financial Plan

In September 2007, Chesapeake announced an enhanced financial plan designed to monetize latent balance sheet value and to fully fund its planned capital expenditures through at least 2009 without accessing public capital markets. Since then, the company has successfully implemented multiple aspects of the plan and anticipates further progress during 2008 and 2009. Chesapeake believes its planned future transactions in the asset and financial markets will allow it to monetize additional assets for approximately $3 billion by the end of 2009 that, in management's opinion, have not been adequately reflected in the company's market valuation historically.

Producing Property Monetizations and Asset Sales - On December 31, 2007, the company monetized certain Chesapeake-operated long-lived producing assets in Kentucky and West Virginia and retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores. Chesapeake received $1.1 billion for the sale of a volumetric production payment on the Appalachian assets covering proved reserves of approximately 208 bcfe and current production of approximately 55 million cubic feet of natural gas equivalent (mmcfe) per day. For accounting purposes, the transaction was treated as a sale and the company's proved reserves were reduced accordingly. The company also plans to pursue additional monetizations of similarly mature properties in 2008 and 2009 and anticipates further proceeds of approximately $2.0 billion.

In the 2008 first quarter, the company sold non-core oil and natural gas assets in the Rocky Mountains and in the southeastern Oklahoma Woodford Shale play for proceeds of approximately $250 million. The sales involved approximately six mmcfe of daily production and 32 bcfe of proved reserves.

Midstream Partnership - Chesapeake is currently in the process of forming a private partnership to own a non-operating interest in its midstream natural gas assets outside of Appalachia, which consist primarily of gas gathering systems and processing assets. These assets currently generate annualized cash flow from operating activities in excess of $150 million and are expected to grow substantially over at least the next three years as the company expands its gathering systems in multiple operating areas, particularly in the Fort Worth Barnett and Arkansas Fayetteville Shale plays. The company anticipates raising $1 billion in the first half of 2008 by selling a minority interest in the partnership.

Oil and Natural Gas Production Sets Record for 26th Consecutive Quarter and 18th Consecutive Year; 2007 Fourth Quarter Average Daily Production Increases 34% over the 2006 Fourth Quarter and Full Year 2007 Production Increases 23% over Full Year 2006

Daily production for the 2007 fourth quarter averaged 2.219 bcfe, an increase of 193 mmcfe, or 10%, over the 2.026 bcfe produced per day in the 2007 third quarter and an increase of 566 mmcfe, or 34%, over the 1.653 bcfe of daily production in the 2006 fourth quarter.

Chesapeake's 2007 fourth quarter production of 204.2 bcfe was comprised of 187.8 bcf (92% on a natural gas equivalent basis) and 2.74 mmbbls (8% on a natural gas equivalent basis). Chesapeake's average daily production for the quarter of 2.219 bcfe consisted of 2.041 bcf and 29,728 bbls.

The company's sequential and year-over-year growth rates for its 2007 fourth quarter natural gas production were 10% and 35%, respectively, while the company's sequential and year-over-year growth rates for its oil production were 2% and 23%, respectively. The 2007 fourth quarter was Chesapeake's 26th consecutive quarter of sequential U.S. production growth. Over these 26 quarters, Chesapeake's U.S. production has increased 467%, for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%. Chesapeake's daily production for the 2007 full year averaged 1.957 bcfe, an increase of 372 mmcfe, or 23%, over the 1.585 bcfe of daily production for the 2006 full year.

Chesapeake's 2007 full year production of 714.3 bcfe was comprised of 655.0 bcf (92% on a natural gas equivalent basis) and 9.882 mmbbls (8% on a natural gas equivalent basis). Chesapeake's average daily production for the 2007 full year of 1.957 bcfe consisted of 1.794 bcf and 27,074 bbls. The company's growth rate for its 2007 full year natural gas production was 24% and its growth rate for 2007 full year oil production was 14%. The 2007 full year was Chesapeake's 18th consecutive year of sequential production growth.

Oil and Natural Gas Proved Reserves Reach Record Level of 10.9 Tcfe; 2007 Full Year Drilling and Acquisition Costs Average $2.08 per Mcfe; Company Adds 1.9 Tcfe for a Reserve Replacement Rate of 369%

Chesapeake began 2007 with estimated proved reserves of 8.956 trillion cubic feet of natural gas equivalent (tcfe) and ended the year with 10.879 tcfe, an increase of 1.923 tcfe, or 21%. During the year, Chesapeake replaced its 714 bcfe of production with an estimated 2.637 tcfe of new proved reserves for a reserve replacement rate of 369%. Reserve replacement through the drillbit was 2.468 tcfe, or 346% of production and 94% of the total increase (including 1.248 tcfe of positive performance revisions, of which 1.207 tcfe relate to infill drilling and increased density locations, and 97 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and December 31, 2007). Reserve replacement through the acquisition of proved reserves completed during the year was 377 bcfe, or 53% of production and 14% of the total increase. Divestments of proved reserves during the year totaled 208 bcfe for proceeds of $1.1 billion at a sales price of $5.49 per mcfe.

Chesapeake's total drilling and acquisition costs for the year were $2.08 per mcfe (excluding costs of $343 million for seismic, $1.1 billion for acquisition of unproved properties, $1.1 billion to acquire new leasehold, $254 million for capitalized interest on leasehold and unproved property and $159 million relating to tax basis step-up and asset retirement obligations, as well as positive revisions of proved reserves from higher oil and natural gas prices). Excluding these same items, Chesapeake's exploration and development costs through the drillbit were $2.13 per mcfe during the year while reserve replacement costs through acquisitions of proved reserves were $1.78 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 16 of this release.

During 2007, Chesapeake continued the industry's most active drilling program and drilled 1,992 gross (1,695 net) operated wells and participated in another 1,679 gross (224 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during the year, Chesapeake invested $4.3 billion in operated wells (using an average of 140 operated rigs) and $0.7 billion in non-operated wells (using an average of 105 non-operated rigs).

As of December 31, 2007, 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 $20.6 billion and $15.0 billion, respectively, using field differential adjusted prices of $6.19 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). Chesapeake's current PV-10 changes by approximately $390 million for every $0.10 per mcf change in natural gas prices and approximately $56 million for every $1.00 per bbl change in oil prices.

By comparison, the December 31, 2006 PV-10 and standardized measure of the company's proved reserves were $13.6 billion and $10.0 billion, respectively, using field differential adjusted prices of $5.41 per mcf (based on a NYMEX year-end price of $5.64 per mcf) and $56.25 per bbl (based on a NYMEX year-end price of $61.15 per bbl). A reconciliation of PV-10 and standardized measure is presented on page 22 of this release.

In addition to the PV-10 value of its proved reserves, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments, long-term derivative instruments and other non-current assets) was $3.2 billion as of December 31, 2007 and $2.8 billion as of December 31, 2006.

Chesapeake's Leasehold and 3-D Seismic Inventories Increase to 13 Million Net Acres and 19 Million Acres; Risked Unproved Reserves in the Company's Inventory Reach 33 Tcfe While Unrisked Unproved Reserves Reach 100 Tcfe

Since 2000, Chesapeake has invested $9.4 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (13.2 million net acres) and 3-D seismic (19.2 million acres) in the U.S. On this leasehold, Chesapeake has an estimated 3.9 tcfe of proved undeveloped reserves and approximately 33 tcfe of risked unproved reserves (100 tcfe of unrisked unproved reserves). The company is currently using 145 operated drilling rigs to further develop its inventory of approximately 36,300 net drillsites, representing more than a 10-year inventory of drilling projects.

Chesapeake characterizes its drilling inventory by one of four play types: conventional gas resource, unconventional gas resource, emerging unconventional gas resource or Appalachian Basin 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 highlights notable projects in each play.

Play Area	CHK Net Acreage	Est. Drilling Density (Acres)	Risked Net Undrilled Wells	Est. Avg. Average Well Cost ($000)	Est. Reserves Per Well (bcfe)
Conventional					
Southern Oklahoma	345,000	120	600	$ 3,500	2.20
South Texas	145,000	80	400	$ 3,300	2.00
Mountain Front	140,000	320	100	$ 9,000	5.00
Other Conventional	2,970,000	Various	3,900	Various	Various
Conventional Sub-total	3,600,000		5,000		
Unconventional					
Fort Worth Barnett Shale	260,000	50	3,550	$ 2,600	2.50
Fayetteville Shale (Core)	585,000	80	5,725	$ 3,000	2.00
Sahara	850,000	70	9,000	$ 880	0.55
Deep Haley	550,000	320	325	$12,000	6.00
Ark-La-Tex	220,000	55	950	$ 1,700	0.90
Granite, Atoka and Colony Washes	200,000	80	1,225	$ 4,000	2.30
Other Unconventional	935,000	Various	625	Various	Various
Unconventional Sub-					

total	3,600,000		21,400		
Emerging Unconventional					
Delaware Basin Shales	815,000	160	500	$ 6,500	3.00
Deep Bossier	390,000	320	125	$10,000	5.00
Ardmore Basin Woodford Shale	170,000	160	200	$ 3,400	1.70
Alabama Shales	315,000	ND	100	ND	ND
Other Emerging Unconventional	310,000	Various	125	Various	Various
Emerging Unconventional Sub-total	2,000,000		1,050		
Appalachia					
Marcellus Shale	1,030,000	160	1,400	$ 1,600	1.25
Lower Huron and Other	2,970,000	Various	7,450	Various	Various
Appalachia Sub-total	4,000,000		8,850		
Total	13,200,000		36,300		

Play Area	Total Proved Reserves (bcfe)	Risked Unproved Reserves (bcfe)	Unrisked Unproved Reserves (bcfe)	Current Daily Production (mmcfe)	Current Operated Rig Count
Conventional					
Southern Oklahoma	849	800	3,200	200	7
South Texas	428	500	1,900	130	5
Mountain Front	217	300	1,100	95	2
Other Conventional	2,449	3,000	16,500	560	16
Conventional Sub-total	3,943	4,600	22,700	985	30
Unconventional					
Fort Worth Barnett Shale	2,062	5,900	7,300	410	39
Fayetteville Shale (Core)	335	9,300	21,500	100	11
Sahara	1,050	3,500	4,000	180	12
Deep Haley	291	1,300	7,300	100	9
Ark-La-Tex	615	400	1,900	120	6
Granite, Atoka and Colony Washes	881	1,800	2,500	160	11
Other Unconventional	196	600	700	30	8
Unconventional Sub-total	5,430	22,800	45,200	1,100	96
Emerging Unconventional					
Delaware Basin Shales	15	1,200	11,700	ND	4
Deep Bossier	22	400	4,500	ND	3
Ardmore Basin Woodford Shale	32	300	1,300	ND	2
Alabama Shales	0	100	2,000	ND	1

Other Emerging Unconventional	3	300	2,500	ND	1
Emerging Unconventional Sub-total	72	2,300	22,000	25	11
Appalachia					
Marcellus Shale	ND	1,400	5,700	ND	2
Lower Huron and Other	ND	2,100	3,900	ND	6
Appalachia Sub-total	1,402	3,500	9,600	85	8
Total	10,847	33,200	99,500	2,195	145

Note: Data above is pro forma for divestitures of approximately 32 bcfe of proved reserves and 37,000 net acres of leasehold post year-end 2007. The table also reflects the effects of the company's VPP transaction that reduced Appalachian production and proved reserves by 55 mmcfe per day and 208 bcfe as of December 31, 2007.

ND = Not disclosed

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report outstanding financial and operational results for the 2007 fourth quarter and full year. We are particularly proud of our success through the drillbit that enabled the company to deliver reserve and production growth well above our expectations at very attractive finding costs. In addition, our unrivalled inventory of leasehold, 3-D seismic and undrilled locations combined with our talented, motivated, hard-working and growing employee workforce should provide many more years of increases in reserves, production and net asset value per share. Finally, we are also pleased with our progress in implementing the various elements of our enhanced financial plan that should enable Chesapeake to deliver superior growth and financial returns without accessing the public capital markets for the foreseeable future."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, February 22, 2008, at 9:00 a.m. EST. The telephone number to access the conference call is 913-312-0822 or toll-free 888-230-5503. The passcode for the call is 4323736. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 a.m. EST. For those unable to participate in the conference call, a replay will be available for audio playback from noon EST on February 22, 2008, and will run through midnight EST on Friday, March 7, 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 4323736. 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 oil and natural gas reserves, expected oil and natural gas production and future expenses, projections of future oil and natural gas prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and 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 "Risks Related to our Business" under "Risk Factors" in the Offer to Exchange attached as an exhibit to each of the two Schedules TO we filed with the Securities and Exchange Commission on October 23, 2007. These risk factors include the volatility of oil and natural gas prices; the limitations our level of indebtedness may have on our financial flexibility; our ability to compete effectively against strong independent oil and natural gas 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 oil and natural gas reserves and projecting future rates of production and the amount and timing of development expenditures; uncertainties in evaluating oil and natural gas 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 oil and natural gas properties resulting in ceiling test write-downs; lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower oil and natural gas 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 oil and natural gas 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 largest independent and third-largest overall 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 Mid-Continent, Fort Worth Barnett Shale, Fayetteville Shale, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast, Ark-La-Tex and Appalachian Basin regions of the United States. The company'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:	December 31, 2007 $	$/mcfe	December 31, 2006 $	$/mcfe
REVENUES:				
Oil and natural gas sales	1,460	7.15	1,429	9.39
Oil and natural gas marketing sales	594	2.91	406	2.67
Service operations revenue	35	0.17	33	0.22
Total Revenues	2,089	10.23	1,868	12.28
OPERATING COSTS:				
Production expenses	180	0.88	125	0.82
Production taxes	64	0.32	47	0.31
General and administrative expenses	75	0.37	40	0.26
Oil and natural gas marketing expenses	575	2.81	390	2.57
Service operations expense	27	0.13	19	0.12
Oil and natural gas depreciation, depletion and amortization	521	2.55	382	2.51
Depreciation and amortization of other assets	33	0.16	30	0.20

Total Operating Costs	1,475	7.22	1,033	6.79
INCOME FROM OPERATIONS	614	3.01	835	5.49
OTHER INCOME (EXPENSE):				
Interest and other income	3	0.01	6	0.04
Interest expense	(128)	(0.63)	(81)	(0.53)
Total Other Income (Expense)	(125)	(0.62)	(75)	(0.49)
INCOME BEFORE INCOME TAXES	489	2.39	760	5.00
Income Tax Expense:				
Current	9	0.04	5	0.03
Deferred	177	0.87	284	1.87
Total Income Tax Expense	186	0.91	289	1.90
NET INCOME	303	1.48	471	3.10
Preferred stock dividends	(17)	(0.08)	(25)	(0.17)
Loss on exchange/conversion of preferred stock	(128)	(0.63)	--	--
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	158	0.77	446	2.93
EARNINGS PER COMMON SHARE:				
Basic	$ 0.34		$ 1.05	
Assuming dilution	$ 0.33		$ 0.96	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	468		426	
Assuming dilution	476		491	

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

	December 31,		December 31,	
TWELVE MONTHS ENDED:	2007		2006	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	5,624	7.88	5,619	9.71
Oil and natural gas marketing sales	2,040	2.86	1,577	2.73

Service operations revenue	136	0.19	130	0.23
Total Revenues	7,800	10.93	7,326	12.67
OPERATING COSTS:				
Production expenses	640	0.90	490	0.85
Production taxes	216	0.30	176	0.31
General and administrative expenses	243	0.34	139	0.24
Oil and natural gas marketing expenses	1,969	2.76	1,522	2.63
Service operations expense	94	0.13	68	0.12
Oil and natural gas depreciation, depletion and amortization	1,835	2.57	1,359	2.35
Depreciation and amortization of other assets	154	0.22	104	0.18
Employee retirement expense	--	--	55	0.09
Total Operating Costs	5,151	7.22	3,913	6.77
INCOME FROM OPERATIONS	2,649	3.71	3,413	5.90
OTHER INCOME (EXPENSE):				
Interest and other income	15	0.02	26	0.05
Interest expense	(406)	(0.57)	(301)	(0.52)
Gain on sale of investment	83	0.12	117	0.20
Total Other Income (Expense)	(308)	(0.43)	(158)	(0.27)
INCOME BEFORE INCOME TAXES	2,341	3.28	3,255	5.63
Income Tax Expense:				
Current	29	0.04	5	0.01
Deferred	861	1.21	1,247	2.16
Total Income Tax Expense	890	1.25	1,252	2.17
NET INCOME	1,451	2.03	2,003	3.46
Preferred stock dividends	(94)	(0.13)	(89)	(0.15)
Loss on exchange/conversion of preferred stock	(128)	(0.18)	(10)	(0.02)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	1,229	1.72	1,904	3.29
EARNINGS PER COMMON SHARE:				
Basic	$ 2.69		$ 4.78	
Assuming dilution	$ 2.62		$ 4.35	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions)				
Basic	456		398	

Assuming dilution	487	459

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

	December 31, 2007	December 31, 2006
Cash	$ 1	$ 3
Other current assets	1,395	1,151
Total Current Assets	1,396	1,154
Property and equipment (net)	28,337	21,904
Other assets	1,001	1,359
Total Assets	$ 30,734	$ 24,417
Current liabilities	$ 2,760	$ 1,890
Long-term debt, net	10,950	7,376
Asset retirement obligation	236	193
Other long-term liabilities	692	390
Deferred tax liability	3,966	3,317
Total Liabilities	18,604	13,166
Stockholders' Equity	12,130	11,251
Total Liabilities & Stockholders' Equity	$ 30,734	$ 24,417
Common Shares Outstanding	511	457

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
(in millions)
(unaudited)

	December 31, 2007	% of Total Book Capitalization	December 31, 2006	% of Total Book Capitalization
Long-term debt, net	$ 10,950	47	$ 7,376	40
Stockholders' equity	12,130	53	11,251	60
Total	$ 23,080	100	$ 18,627	100

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2007 ADDITIONS TO OIL AND NATURAL GAS PROPERTIES
($ in millions, except per unit data)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe

Exploration and development costs	$ 5,055	2,371,063(a)	2.13
Acquisition of proved properties	671	377,230	1.78
Subtotal	5,726	2,748,293	2.08
Divestitures	(1,142)	(208,141)	(5.49)
Geological and geophysical costs	343	--	
Adjusted subtotal	4,927	2,540,152	1.94
Revisions - price	--	97,118	
Leasehold acquisition costs	886	--	
Lease brokerage costs and recording fees	224	--	
Acquisition of unproved properties and other	1,101	--	
Capitalized interest on leasehold and unproved property	254	--	
Adjusted subtotal	7,392	2,637,270	2.80
Tax basis step-up	131	--	
Asset retirement obligation and other	29	--	
Total	$ 7,552	2,637,270	2.86

(a) Includes 1,248 bcfe of positive performance revisions (1,207 bcfe relating to infill drilling and increased density locations and 41 bcfe of other performance related revisions) and excludes positive revisions of 97 bcfe resulting from oil and natural gas price increases between December 31, 2006 and 2007.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
TWELVE MONTHS ENDED DECEMBER 31, 2007
(unaudited)

	Mmcfe
Beginning balance, 01/01/07	8,955,614
Extensions and discoveries	1,122,986
Acquisitions	377,230
Divestitures	(208,141)
Revisions - performance	1,248,077
Revisions - price	97,118
Production	(714,261)
Ending balance, 12/31/07	10,878,623
Reserve replacement	2,637,270
Reserve replacement ratio (a)	369%

(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, thereby providing some information on the sources of future production. 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 - OIL AND NATURAL GAS SALES AND INTEREST EXPENSE

(unaudited)

	THREE MONTHS ENDED December 31, 2007	THREE MONTHS ENDED December 31, 2006	TWELVE MONTHS ENDED December 31, 2007	TWELVE MONTHS ENDED December 31, 2006
Oil and Natural Gas Sales ($ in millions):				
Oil sales	$ 236	$ 122	$ 678	$ 527
Oil derivatives - realized gains (losses)	(38)	11	(11)	(15)
Oil derivatives - unrealized gains (losses)	(180)	4	(235)	28
Total Oil Sales	18	137	432	540
Natural gas sales	1,199	817	4,117	3,343
Natural gas derivatives - realized gains (losses)	324	436	1,214	1,269
Natural gas derivatives - unrealized gains (losses)	(81)	39	(139)	467
Total Natural Gas Sales	1,442	1,292	5,192	5,079
Total Oil and Natural Gas Sales	$1,460	$1,429	$5,624	$5,619
Average Sales Price - excluding gains (losses) on derivatives:				
Oil ($ per bbl)	$86.24	$55.07	$68.64	$60.86
Natural gas ($ per mcf)	$ 6.38	$ 5.89	$ 6.29	$ 6.35
Natural gas equivalent ($ per mcfe)	$ 7.03	$ 6.17	$ 6.71	$ 6.69
Average Sales Price - excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$72.58	$59.95	$67.50	$59.14
Natural gas ($ per mcf)	$ 8.11	$ 9.03	$ 8.14	$ 8.76
Natural gas equivalent ($ per mcfe)	$ 8.43	$ 9.11	$ 8.40	$ 8.86
Interest Expense ($ in millions):				
Interest	$ 99	$ 79	$ 365	$ 301
Derivatives - realized (gains) losses	1	3	1	2
Derivatives - unrealized (gains) losses	28	(1)	40	(2)
Total Interest Expense	$ 128	$ 81	$ 406	$ 301

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

	December 31, 2007	December 31, 2006
THREE MONTHS ENDED:		

Beginning cash	$ 2	$ 1
Cash provided by operating activities	1,544	1,861
Cash (used in) investing activities	(1,434)	(2,274)
Cash provided by financing activities	(111)	415
Ending cash	1	3

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TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006
Beginning cash	$ 3	$ 60
Cash provided by operating activities	4,932	4,843
Cash (used in) investing activities	(7,922)	(8,942)
Cash provided by financing activities	2,988	4,042
Ending cash	1	3

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

THREE MONTHS ENDED:	December 31, 2007	September 30, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$1,544	$1,267	$1,861
Adjustments:			
Changes in assets and liabilities	(222)	(182)	(766)
OPERATING CASH FLOW(a)	$1,322	$1,085	$1,095

(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 an oil and natural gas 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 oil and natural gas 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:	December 31, 2007	September 30, 2007	December 31, 2006
NET INCOME	$ 303	$ 372	$ 471
Income tax expense	186	228	289
Interest expense	128	116	81
Depreciation and amortization of other assets	33	45	30
Oil and natural gas depreciation, depletion and amortization	521	479	382
EBITDA(b)	$1,171	$1,240	$1,253

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(b) Ebitda represents net income before income tax expense, interest expense, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit 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:	December 31, 2007	September 30, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 1,544	$ 1,267	$ 1,861
Changes in assets and liabilities	(222)	(182)	(766)
Interest expense	128	116	81
Unrealized gains (losses) on oil and natural gas derivatives	(261)	45	43
Other non-cash items	(18)	(6)	34
EBITDA	$ 1,171	$ 1,240	$ 1,253

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

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006	December 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$ 4,932	$ 4,843	$ 2,407
Adjustments:			
Changes in assets and liabilities	(325)	(798)	19
OPERATING CASH FLOW(a)	$ 4,607	$ 4,045	$ 2,426

(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 an oil and natural gas 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 oil and natural gas 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, 2007	December 31, 2006	December 31, 2005

NET INCOME	$ 1,451	$ 2,003	$ 948
Income tax expense	890	1,252	545
Interest expense	406	301	220
Depreciation and amortization of other assets	154	104	51
Oil and natural gas depreciation, depletion and amortization	1,835	1,359	894
EBITDA(b)	$ 4,736	$ 5,019	$ 2,658

(b) Ebitda represents net income before income tax expense, interest expense, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit 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:

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006	December 31, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$4,932	$4,843	$2,407
Changes in assets and liabilities	(325)	(798)	19
Interest expense	406	301	220
Unrealized gains (losses) on oil and natural gas derivatives	(375)	496	41
Other noncash items	98	177	(29)
EBITDA	$4,736	$5,019	$2,658

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

THREE MONTHS ENDED:	December 31, 2007	September 30, 2007	December 31, 2006
Net income available to common shareholders	$ 158	$ 346	$ 446
Adjustments:			
Loss on conversion/exchange of preferred stock	128	--	--
Unrealized (gains) losses on derivatives, net of tax	180	(16)	(27)
Adjusted net income available to common			

shareholders(1)	466	330	419
Preferred dividends	17	26	25
Total adjusted net income	$ 483	$ 356	$ 444
Weighted average fully diluted shares outstanding(2)	520	517	491
Adjusted earnings per share assuming dilution	$ 0.93	$ 0.69	$ 0.90

(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 oil and natural gas 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:	December 31, 2007	September 30, 2007	December 31, 2006
EBITDA	$ 1,171	$ 1,240	$ 1,253
Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas derivatives	261	(45)	(43)
Adjusted ebitda(1)	$ 1,432	$ 1,195	$ 1,210

(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 oil and natural gas 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, 2007	December 31, 2006	December 31, 2005
Net income available to common shareholders	$1,229	$1,904	$ 880
Adjustments:			
Loss on conversion/exchange of preferred stock	128	10	26
Unrealized (gains) losses on derivatives, net of tax	257	(308)	(27)
Gain on sale of investment, net of tax	(51)	(73)	--
Employee retirement expense, net of tax	--	34	--
Cumulative impact of income tax rate change	--	15	--
Loss on repurchases or exchanges of senior notes, net of tax	--	--	45
Reversal of severance tax accrual, net of tax	--	(7)	--
Adjusted net income available to common shareholders(1)	1,563	1,575	924
Preferred dividends	94	89	42
Total adjusted net income	$1,657	$1,664	$ 966
Weighted average fully diluted shares outstanding(2)	517	461	375
Adjusted earnings per share assuming dilution	$ 3.21	$ 3.61	$2.57

(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 oil and natural gas 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)

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006	December 31, 2005
EBITDA	$4,736	$5,019	$2,658

Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas derivatives	375	(496)	(41)
Reversal of severance tax accrual	--	(12)	--
Gain on sale of investment	(83)	(117)	--
Employee retirement expense	--	55	--
Loss on repurchase or exchange of senior notes	--	--	70
Adjusted EBITDA(1)	$5,028	$4,449	$2,687

(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 oil and natural gas producing companies.

b. Adjusted EBITDA 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.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF PV-10
($ in millions)
(unaudited)

	December 31, 2007	December 31, 2006
Standardized measure of discounted future net cash flows	$14,962	$10,007
Discounted future cash flows for income taxes	5,611	3,640
Discounted future net cash flows before income taxes (PV-10)	$20,573	$13,647

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, 2007 PV-10 and standardized measure were calculated using field differential adjusted prices of $6.19 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 company's December 31, 2006 PV-10 and standardized measure were calculated using field differential adjusted prices of $5.41 per mcf (based on a NYMEX year-end price of $5.64 per mcf) and $56.25 per bbl (based on a NYMEX year-end price of $61.15 per bbl).

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF FEBRUARY 21, 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 February 21, 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 November 6, 2007 Outlook are in italicized bold and are explained as follows:

1) We are providing our first guidance for the 2008 first quarter and increasing our prior production guidance for the full years 2008 and 2009. Guidance in this Outlook excludes production expected to be sold in conjunction with various anticipated monetization transactions in 2008 and 2009, whereas guidance issued on November 6, 2007 included such volumes;

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

3) Certain cost assumptions, shares outstanding and budgeted capital expenditure assumptions have been updated; and

4) Our projected book tax rate has been updated.

	Quarter Ending 3/31/2008	Year Ending 12/31/2008	Year Ending 12/31/2009
Estimated Production(a)			
Oil - mbbls	2,675	10,500	11,000
Natural gas - bcf	182 - 186	788 - 798	892 - 902
Natural gas equivalent - bcfe	198 - 202	851 - 861	958 - 968
Daily natural gas equivalent midpoint - mmcfe	2,200	2,340	2,640
NYMEX Prices (b) (for calculation of realized hedging effects only):			
Oil - $/bbl	$ 80.98	$ 76.49	$ 75.00
Natural gas - $/mcf	$ 7.55	$ 7.51	$ 7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	$ (6.98)	$ (2.11)	$ 6.00
Natural gas - $/mcf	$ 1.84	$ 1.39	$ 0.63
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	496	504
Diluted	525	526	534
Budgeted Capital Expenditures, net - in millions:			
Drilling	$1,100 - 1,200	$ 4,400 - 4,800	$ 4,400 - 4,800
Leasehold and property acquisition costs	$ 400 - 450	$ 1,200 - 1,400	$ 1,200 - 1,400
Monetization of oil and gas properties(a)	--	$ (1,000)	$ (1,000)
Geological and geophysical costs	$ 75	$ 250 - 300	$ 250 - 300
Total budgeted capital expenditures, net	$1,575 - 1,725	$4,850 - $5,500	$4,850 - $5,500

(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 January 2008 and NYMEX natural gas prices have been updated for actual contract prices through February 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; $76.49 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during calendar 2008; and $75.00 per bbl of oil and $7.50 to $8.50 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	133.0	$ 8.51	194	69%	$ 44.5	$ 0.23

Q3 2008	132.5	$ 8.69	205	65%	$ 40.5	$ 0.20
Q4 2008	119.5	$ 9.23	210	57%	$ 45.3	$ 0.22
Total 2008(1)	516.0	$ 8.74	793	65%	$ 286.7	$ 0.36
Total 2009(1)	276.0	$ 9.04	897	31%	$ 12.8	$ 0.01

(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 191 bcf in 2008 and $5.45 to $6.50 covering 214 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	2.7	$7.50	$ 9.68	194	1%
Q3 2008	2.8	$7.50	$ 9.68	205	1%
Q4 2008	2.8	$7.50	$ 9.68	210	1%
Total 2008(1)	26.8	$7.41	$ 9.40	793	3%
Total 2009(1)	45.7	$8.14	$10.82	897	5%

(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 110 bcf of production in 2008 at a weighed average price of $10.26 for a weighted average premium of $0.66 and 142 bcf of production in 2009 at a weighed average price of $11.18 for a weighted average premium of $0.48.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(1):	Volume in Bcf's	NYMEX plus(1):
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

(1) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($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)	194	5%
Q3 2008	9.7	$4.68	$7.41	($2.74)	205	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	210	5%
Total 2008	38.4	$4.68	$8.02	($3.34)	793	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	897	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	1,866	75.22	2,605	72%	$ (4.7)	$(1.81)
Q3 2008	1,886	75.11	2,610	72%	$ (4.6)	$(1.76)
Q4 2008	1,702	76.79	2,610	65%	$ (4.7)	$(1.82)
Total 2008(1)	7,277	$75.24	10,500	69%	$(17.2)	$(1.65)
Total						

2009(1)	8,030	$81.60	11,000	73%	--	--

(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 4,090 mbbls in 2008 and from $52.50 to $60.00 covering 7,483 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.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF NOVEMBER 6, 2007

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 21, 2008

Quarter Ending December 31, 2007 and Years Ending December 31, 2007, 2008 and 2009.

We have adopted a policy of periodically providing guidance on certain factors that affect our future financial performance. As of November 6, 2007, we are using the following key assumptions in our projections for the fourth quarter of 2007 and the full years 2007, 2008 and 2009.

The primary changes from our September 4, 2007 Outlook are in italicized bold and are explained as follows:

1) We are increasing our prior production guidance for the 2007 fourth quarter and for 2008 and 2009;

2) Production assumptions have been updated;

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

4) Certain cost assumptions, shares outstanding and budgeted capital expenditure assumptions have been updated.

	Quarter Ending 12/31/2007	Year Ending 12/31/2007
Estimated Production(a)		
Oil - mbbls	2,500	9,600
Natural gas - bcf	181.5 - 183.5	649 - 651
Natural gas equivalent - bcfe	196.5 - 198.5	707 - 709
Daily natural gas equivalent midpoint - in mmcfe	2,150	1,940
NYMEX Prices (b) (for calculation of realized hedging effects only):		
Oil - $/bbl	$ 79.84	$ 69.60
Natural gas - $/mcf	$ 7.07	$ 6.89
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Oil - $/bbl	$ (5.40)	$ 1.28
Natural gas - $/mcf	$ 1.68	$ 1.84
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	7 - 9%	7 - 9%
Natural gas - $/mcf	10 - 14%	10 - 14%
Operating Costs per Mcfe of Projected Production:		
Production expense	$ 0.90 - 1.00	$ 0.90 - 1.00
Production taxes (generally 5.5% of O&G revenues) (c)	$ 0.35 - 0.40	$ 0.35 - 0.40
General and administrative	$ 0.25 - 0.30	$ 0.25 - 0.30
Stock-based compensation (non-cash)	$ 0.08 - 0.10	$ 0.08 - 0.10

DD&A of oil and natural gas assets	$ 2.60 - 2.70	$ 2.50 - 2.70
Depreciation of other assets	$ 0.18 - 0.20	$ 0.20 - 0.24
Interest expense(d)	$ 0.55 - 0.60	$ 0.55 - 0.60
Other Income per Mcfe:		
Oil and natural gas marketing income	$ 0.04 - 0.06	$ 0.08 - 0.10
Service operations income	$ 0.04 - 0.06	$ 0.05 - 0.07
Book Tax Rate (About Equals 97% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	480	459
Diluted	520	519
Budgeted Capital Expenditures, net - in millions:		
Drilling	$ 1,000 - 1,100	$ 4,250 - 4,450
Leasehold and property acquisition costs	$ 300 - 350	$ 1,200 - 1,400
Monetization of oil and gas properties(a)	$(1,000 - 1,200)	$(1,000 - 1,200)
Geological and geophysical costs	$ 50 - 75	$ 250 - 300
Total budgeted capital expenditures, net	$ 325 - 350	$ 4,700 - 4,950

	Year Ending 12/31/2008	Year Ending 12/31/2009
Estimated Production(a)		
Oil - mbbls	10,500	11,000
Natural gas - bcf	788 - 798	892 - 902
Natural gas equivalent - bcfe	851 - 861	958 - 968
Daily natural gas equivalent midpoint - in mmcfe	2,340	2,640
NYMEX Prices (b) (for calculation of realized hedging effects only):		
Oil - $/bbl	$ 75.00	$ 75.00
Natural gas - $/mcf	$ 7.50	$ 7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Oil - $/bbl	$ (0.44)	$ 3.88
Natural gas - $/mcf	$ 1.36	$ 0.53
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	7 - 9%	7 - 9%
Natural gas - $/mcf	10 - 14%	10 - 14%
Operating Costs per Mcfe of Projected Production:		
Production expense	$ 0.90 - 1.00	$ 0.90 - 1.00
Production taxes (generally 5.5% of O&G revenues) (c)	$ 0.35 - 0.40	$ 0.35 - 0.40
General and administrative	$ 0.25 - 0.30	$ 0.25 - 0.30
Stock-based compensation (non-cash)	$ 0.10 - 0.12	$ 0.10 - 0.12
DD&A of oil and natural gas assets	$ 2.50 - 2.70	$ 2.50 - 2.70
Depreciation of other assets	$ 0.26 - 0.30	$ 0.26 - 0.30
Interest expense(d)	$ 0.55 - 0.60	$ 0.55 - 0.60
Other Income per Mcfe:		
Oil and natural gas marketing income	$ 0.07 - 0.09	$ 0.07 - 0.09
Service operations income	$ 0.05 - 0.07	$ 0.05 - 0.07

Book Tax Rate (About Equals 97% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	496	504
Diluted	525	532
Budgeted Capital Expenditures, net - in millions:		
Drilling	$ 4,000 - 4,200	$ 4,000 - 4,200
Leasehold and property acquisition costs	$ 1,200 - 1,400	$ 1,200 - 1,400
Monetization of oil and gas properties(a)	$(1,000 - 1,200)	$(1,000 - 1,200)
Geological and geophysical costs	$ 200 - 250	$ 200 - 250
Total budgeted capital expenditures, net	$4,400 - $4,650	$4,400 - $4,650

(a) The 2008 and 2009 forecasts assume that the company monetizes producing properties in multiple transactions beginning late in the fourth quarter of 2007. For accounting purposes, the company anticipates that the proposed monetization transactions will be treated as prepaid sales rather than property sales. As a result, Chesapeake's forecast does not reflect a reduction of production volumes from the monetized properties.

(b) Oil NYMEX prices have been updated for actual contract prices through October 2007 and natural gas NYMEX prices have been updated for actual contract prices through November 2007.

(c) Severance tax per mcfe is based on NYMEX prices of: $79.84 per bbl of oil and $6.70 to $7.80 per mcf of natural gas during Q4 2007; $69.60 per bbl of oil and $6.80 to $7.90 per mcf of natural gas during calendar 2007; and $75.00 per bbl of oil and $6.80 to $7.90 per mcf of natural gas during calendar 2008 and 2009.

(d) 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 loses 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
Q4 2007(1)	141.4	$ 7.77	182.5	78%	$ 158.1	$ 0.87
Q1 2008	130.5	$ 8.74	188	69%	$ 133.0	$ 0.71
Q2 2008	125.4	$ 8.57	194	65%	$ 38.8	$ 0.20
Q3 2008	124.9	$ 8.74	202	62%	$ 35.9	$ 0.18
Q4 2008	117.6	$ 9.27	209	56%	$ 37.7	$ 0.18
Total 2008(1)	498.4	$ 8.82	793	63%	$ 245.4	$ 0.31
Total 2009(1)	233.5	$ 8.98	897	26%	$ 12.5	$ 0.01

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.25 to $6.25 covering 17 bcf in Q4 2007, $5.45 to $6.50 covering 186 bcf in 2008 and $5.45 to $6.50 covering 152 bcf in 2009.

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

	Assuming	Open Collars as a % of

	Open Collars in Bcf's	Avg. NYMEX Floor Price	Avg. NYMEX Ceiling Price	Natural Gas in Bcf's	Estimated Total Production of:	Natural Gas Production
Q4 2007(1)	19.6	$7.13	$ 8.88		182.5	11%
Q1 2008	18.5	$7.36	$ 9.28		188	10%
Q2 2008	2.7	$7.50	$ 9.68		194	1%
Q3 2008	2.8	$7.50	$ 9.68		202	1%
Q4 2008	2.8	$7.50	$ 9.68		209	1%
Total 2008(1)	26.8	$7.41	$ 9.40		793	3%
Total 2009(1)	27.4	$7.97	$11.18		897	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 14 bcf in Q4 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $5.50 to $6.00 covering 27 bcf in 2009.

Note: Not shown above are written call options covering 7 bcf of production in Q4 2007 at a weighted average price of $7.85 for a weighted average premium of $1.13, 110 bcf of production in 2008 at a weighed average price of $10.26 for a weighted average premium of $0.66 and 119 bcf of production in 2009 at a weighed average price of $11.12 for a weighted average premium of $0.54.

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):
Q4 2007	33.3	0.26	9.2	0.35
2008	118.6	0.27	43.9	0.35
2009	86.6	0.29	36.5	0.31
2010	--	--	29.2	0.31
2011	--	--	29.2	0.32
2012	10.7	0.34	--	--
Totals	249.2	$0.28	148.0	$0.33

(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 ($216 million as of September 30, 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
Q4 2007	10.6	$4.82	$8.87	($4.05)	182.5	6%
Q1 2008	9.5	$4.68	$9.42	($4.74)	188	5%
Q2 2008	9.5	$4.68	$7.41	($2.73)	194	5%
Q3 2008	9.7	$4.68	$7.41	($2.74)	202	5%
Q4 2008	9.7	$4.66	$7.84	($3.17)	209	5%
Total 2008	38.4	$4.68	$8.02	($3.34)	793	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	897	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 Swaps ($ millions)	Total Lifted Gain per bbl of Estimated Total Oil Production
Q4 2007(1)	1,564	$72.84	2,500	63%	$(0.5)	$(0.21)
Q1 2008	1,971	72.84	2,470	80%	$ 1.2	$ 0.49
Q2 2008	2,002	72.59	2,560	78%	$ 1.2	$ 0.47
Q3 2008	2,024	72.44	2,690	75%	$ 1.2	$ 0.45
Q4 2008	1,840	73.48	2,780	66%	$ 1.2	$ 0.43
Total 2008(1)	7,837	$72.82	10,500	75%	$ 4.8	$ 0.46
Total 2009(1)	8,030	$78.81	11,000	73%	--	--

(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 736 mbbls in Q4 2007 and 3,478 mbbls in 2008 and from $52.50 to $60.00 covering 7,483 mbbls in 2009.

Note: Not shown above are written call options covering 920 mbbls of production in Q4 2007 at a weighted average price of $79.85 for a weighted average premium of $1.00, 2,564 mbbls of production in 2008 at a weighted average price of $82.50 for a weighted average premium of $3.17 and 2,190 mbbls of production in 2009 at a weighed average price of $75.00 for a weighted average premium of

$5.47.

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