**NEWS RELEASE**

# Chesapeake Energy Corporation Reports Strong Financial and Operational Results for the 2007 First Quarter

**Net Income Available to Common Shareholders Reaches $232 Million on Revenue of $1.6 Billion and Production of 154 Bcfe; Adjusted Net Income Available to Common Shareholders Reaches $425 Million Proved Reserves Reach Record Level of 9.4 Tcfe; Company Delivers First Quarter Reserve Replacement Rate of 410% from 475 Bcfe of Additions Company Provides Updated and Detailed Review of its 18.3 Tcfe of Risked Unproved Reserves Located on its 11.2 Million Net Acres of U.S. Onshore Leasehold**

OKLAHOMA CITY, May 03, 2007 (BUSINESS WIRE) -- Chesapeake Energy Corporation (NYSE:CHK) today reported strong financial and operating results for the first quarter of 2007. For the quarter, Chesapeake generated net income available to common shareholders of $232 million ($0.50 per fully diluted common share), operating cash flow of $1.124 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $924 million (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.580 billion and production of 154 billion cubic feet of natural gas equivalent (bcfe).

The company's 2007 first quarter net income available to common shareholders and ebitda include an unrealized after-tax mark-to-market loss of $193 million resulting from the company's oil and natural gas and interest rate hedging programs. This type of item is typically not included in published estimates of the company's financial results by certain securities analysts.

Excluding this item, Chesapeake generated adjusted net income to common shareholders in the 2007 first quarter of $425 million ($0.87 per fully diluted common share) and adjusted ebitda of $1.234 billion. 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 19 - 20 of this release.

Key Operational and Financial Statistics Summarized Below for the 2007 First Quarter, 2006 Fourth Quarter and 2006 First Quarter

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

| | Three Months Ended: | | |
|---|---|---|---|
| | 3/31/07 | 12/31/06 | 3/31/06 |
| Average daily production (in mmcfe) | 1,707 | 1,653 | 1,519 |
| Natural gas as % of total production | 92 | 91 | 91 |
| Natural gas production (in bcf) | 140.8 | 138.8 | 124.1 |
| Average realized natural gas price ($/mcf) (a) | 9.26 | 9.03 | 9.61 |
| Oil production (in mbbls) | 2,143 | 2,217 | 2,116 |
| Average realized oil price ($/bbl) (a) | 61.13 | 59.95 | 57.12 |
| Natural gas equivalent production (in bcfe) | 153.7 | 152.1 | 136.8 |
| Natural gas equivalent realized price ($/mcfe) (a) | 9.33 | 9.11 | 9.60 |
| Oil and natural gas marketing income ($/mcfe) | .10 | .11 | .10 |
| Service operations income ($/mcfe) | .08 | .09 | .11 |
| Production expenses ($/mcfe) | (.93) | (.82) | (.87) |
| Production taxes ($/mcfe) | (.27) | (.31) | (.40) |
| General and administrative costs ($/mcfe) (b) | (.27) | (.22) | (.17) |

| | | | |
|---|---|---|---|
| Stock-based compensation ($/mcfe) | (.07) | (.04) | (.05) |
| DD&A of oil and natural gas properties ($/mcfe) | (2.56) | (2.51) | (2.23) |
| D&A of other assets ($/mcfe) | (.23) | (.20) | (.17) |
| Interest expense ($/mcfe) (a) | (.50) | (.54) | (.52) |
| Operating cash flow ($ in millions) (c) | 1,124 | 1,095 | 1,047 |
| Operating cash flow ($/mcfe) | 7.31 | 7.20 | 7.66 |
| Adjusted ebitda ($ in millions) (d) | 1,234 | 1,210 | 1,147 |
| Adjusted ebitda ($/mcfe) | 8.03 | 7.96 | 8.39 |
| Net income to common shareholders ($ in millions) | 232 | 446 | 604 |
| Earnings per share - assuming dilution ($) | 0.50 | 0.96 | 1.44 |
| Adjusted net income to common shareholders ($ in millions) (e) | 425 | 418 | 444 |
| Adjusted earnings per share - assuming dilution ($) | 0.87 | 0.90 | 1.07 |

(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 page 20

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

Oil and Natural Gas Production Sets Record for 23rd Consecutive Quarter; 2007 First Quarter Average Daily Production Increases 12% and 3% Over Production in the 2006 First Quarter and the 2006 Fourth Quarter

Daily production for the 2007 first quarter averaged 1.707 bcfe, an increase of 188 million cubic feet of natural gas equivalent (mmcfe), or 12%, over the 1.519 bcfe of daily production in the 2006 first quarter and an increase of 54 mmcfe, or 3%, over the 1.653 bcfe produced per day in the 2006 fourth quarter.

Chesapeake's 2007 first quarter production of 153.7 bcfe was comprised of 140.8 billion cubic feet of natural gas (bcf) (92% on a natural gas equivalent basis) and 2.14 million barrels of oil and natural gas liquids (mmbbls) (8% on a natural gas equivalent basis). Chesapeake's average daily production for the quarter of 1.707 bcfe consisted of 1.564 bcf of natural gas and 23,811 barrels (bbls) of oil. The 2007 first quarter was Chesapeake's 23rd consecutive quarter of sequential U.S. production growth. Over these 23 quarters, Chesapeake's U.S. production has increased 326%, for an average compound quarterly growth rate of 6.5% and an average compound annual growth rate of 29%.

The company's rate of production has recently exceeded 1.8 bcfe per day and based on projected drilling levels and anticipated results, Chesapeake is affirming its previous forecasts for total production growth of 14-18% for 2007 and 10-14% for 2008.

Oil and Natural Gas Proved Reserves Reach Record Level of 9.4 Tcfe; Drilling and Acquisition Costs Average $2.58 per Mcfe as Company Added 475 Bcfe for a Reserve Replacement Rate of 410%

Chesapeake began 2007 with estimated proved reserves of 8.956 trillion cubic feet of natural gas equivalent (tcfe) and ended the quarter with 9.431 tcfe, an increase of 475 bcfe, or 5.3%. During the quarter, Chesapeake replaced its 154 bcfe of production with an estimated 629 bcfe of new proved reserves for a reserve replacement rate of 410%. Reserve replacement through the drillbit was 535 bcfe, or 349% of production (including 205 bcfe of positive performance revisions and 135 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and March 31, 2007) and 85% of the total increase. Reserve replacement through the acquisition of proved reserves was 94 bcfe, or 61% of production and 15% of the total increase.

On a per thousand cubic feet of natural gas equivalent (mcfe) basis, the company's total drilling and acquisition costs were $2.58 per mcfe (excluding costs of $50 million for seismic, $405 million for unproved properties and leasehold acquired during the quarter and $12 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 items described above, Chesapeake's exploration and development costs through the drillbit were $2.66 per mcfe during the 2007 first quarter while reserve replacement costs through acquisitions of proved reserves were $2.21 per mcfe. Total costs incurred in oil and natural gas acquisition, exploration and development during the quarter, including seismic, leasehold, unproved properties, capitalized internal costs, non-cash tax basis step-up from corporate acquisitions and asset retirement obligations, were $1.741 billion. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 17 of this release.

During the 2007 first quarter, Chesapeake continued the industry's most active drilling program and drilled 476 gross (404 net) operated wells and participated in another 394 gross (57 net) wells operated by other companies. The company's drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during the quarter, Chesapeake invested $906 million in operated wells (using an average of 129 operated rigs), $160 million in non-operated wells (using an average of 94 non-operated rigs), $148 million to acquire new leasehold (exclusive of $258 million in unproved leasehold obtained through corporate and asset acquisitions) and $50 million to acquire seismic data.

As of March 31, 2007, Chesapeake's estimated future net cash flows, discounted at an annual rate of 10% before income taxes (PV-10) were $20.2 billion using field differential adjusted prices of $60.75 per bbl (based on a NYMEX quarter-end price of $65.85 per bbl) and $7.01 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $7.34 per mcf).

By comparison, the December 31, 2006 PV-10 of the company's proved reserves was $13.6 billion using field differential adjusted prices of $56.25 per bbl (based on a NYMEX year-end price of $61.15 per bbl) and $5.41 per mcf (based on a NYMEX year-end price of $5.64 per mcf). Additionally, the March 31, 2006 PV-10 of the company's proved reserves was $17.6 billion using field differential adjusted prices of $62.06 per bbl (based on a NYMEX year-end price of $66.33 per bbl) and $6.69 per mcf (based on a NYMEX year-end price of $7.18 per mcf).

Chesapeake's current PV-10 changes by approximately $360 million for every $0.10 per mcf change in natural gas prices and approximately $50 million for every $1.00 per bbl change in oil prices. 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 oil and natural gas 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, the net book value of the company's other assets (including drilling rigs, land and buildings, investments in companies, securities, long-term derivative instruments and other non-current assets) was $2.7 billion as of March 31, 2007, $2.8 billion as of December 31, 2006 and $1.6 billion as of March 31, 2006.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

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

The following tables compare Chesapeake's open hedge position through swaps and collars as well as gains from lifted hedges as of May 3, 2007 to those previously announced as of February 22, 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 May 3, 2007

| | Natural Gas | | Oil | |
|---|---|---|---|---|
| Quarter or Year | % Hedged | $ NYMEX | % Hedged | $ NYMEX |
| 2007 Q2 | 53% | 8.11 | 77% | 71.22 |
| 2007 Q3 | 54% | 8.30 | 77% | 71.61 |

| | | | | |
|---|---|---|---|---|
| 2007 Q4 | 55% | 8.98 | 77% | 71.57 |
| 2007 Q2-Q4 Total | 54% | 8.49 | 77% | 71.47 |
| 2008 Total | 64% | 9.20 | 72% | 72.61 |
| 2009 Total | 13% | 8.87 | 19% | 75.41 |

Open Natural Gas Collar Positions as of May 3, 2007

| Quarter or Year | % Hedged | Average Floor $ NYMEX | Average Ceiling $ NYMEX |
|---|---|---|---|
| 2007 Q2 | 15% | 6.76 | 8.20 |
| 2007 Q3 | 14% | 6.76 | 8.20 |
| 2007 Q4 | 11% | 7.13 | 8.88 |
| 2007 Q2-Q4 Total | 13% | 6.88 | 8.41 |
| 2008 Total | 4% | 7.41 | 9.40 |
| 2009 Total | 2% | 7.50 | 10.72 |

Gains From Lifted Natural Gas Hedges as of May 3, 2007

| Quarter or Year | Total Gain ($ millions) | Assuming Natural Gas Production of: (bcf) | Gain ($ per mcf) |
|---|---|---|---|
| 2007 Q2 | 112 | 147.5 | 0.76 |
| 2007 Q3 | 105 | 158.0 | 0.67 |
| 2007 Q4 | 117 | 172.5 | 0.68 |
| 2007 Q2-Q4 Total | 334 | 478 | 0.70 |
| 2008 Total | 105 | 701 | 0.15 |
| 2009 Total | 4 | 750 | 0.01 |

Additionally, the company has lifted a portion of its oil hedges securing gains of $6.3 million and $4.8 million for the second through fourth quarters of 2007 and for the full year 2008, respectively.

Open Swap Positions as of February 22, 2007

| Quarter or Year | Natural Gas % Hedged | Natural Gas $ NYMEX | Oil % Hedged | Oil $ NYMEX |
|---|---|---|---|---|
| 2007 Q1 | 32% | 9.71 | 56% | 71.98 |
| 2007 Q2 | 50% | 8.06 | 60% | 72.12 |
| 2007 Q3 | 54% | 8.23 | 60% | 71.89 |
| 2007 Q4 | 54% | 8.95 | 60% | 71.61 |
| 2007 Total | 48% | 8.63 | 59% | 71.90 |
| 2008 Total | 60% | 9.20 | 51% | 71.63 |
| 2009 Total | 7% | 9.00 | 2% | 66.10 |

Open Natural Gas Collar Positions as of February 22, 2007

| Quarter or Year | Average Floor % Hedged | Average Ceiling $ NYMEX | $ NYMEX |
|---|---|---|---|
| 2007 Q1 | -- | -- | -- |
| 2007 Q2 | 15% | 6.76 | 8.20 |
| 2007 Q3 | 14% | 6.76 | 8.20 |
| 2007 Q4 | 11% | 7.13 | 8.88 |
| 2007 Total | 10% | 6.88 | 8.41 |
| 2008 Total | 3% | 7.38 | 9.20 |

Gains From Lifted Natural Gas Hedges as of February 22, 2007

| Quarter or Year | Total Gain ($ millions) | Assuming Natural Gas Production of: (bcf) | Gain ($ per mcf) |
|---|---|---|---|
| 2007 Q1 | 281 | 139.0 | 2.02 |
| 2007 Q2 | 114 | 147.5 | 0.77 |
| 2007 Q3 | 104 | 159.0 | 0.65 |
| 2007 Q4 | 116 | 173.5 | 0.67 |
| 2007 Total | 615 | 619 | 0.99 |
| 2008 Total | 105 | 701 | 0.15 |
| 2009 Total | 4 | 750 | 0.01 |

Certain open natural gas swap positions include "knockout" provisions at prices ranging from $5.25 to $6.50 covering 152 bcf in 2007, $5.75 to $6.50 covering 189 bcf in 2008 and $5.90 to $6.25 covering 79 bcf in 2009, and certain open natural gas collar positions include "knockout" provisions at prices ranging from $5.00 to $6.00 covering 52 bcf in 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $6.00 covering 18 bcf in 2009. Also, certain open oil swap positions include "knockout" provisions at prices ranging from $45.00 to $60.00 covering 2.2 mmbbls in 2007, 2.9 mmbbls in 2008 and 1.5 mmbbls in 2009.

The company's updated forecasts for 2007 and 2008 are attached to this release in an Outlook dated May 3, 2007 labeled as Schedule "A", which begins on page 21. This Outlook has been changed from the Outlook dated February 22, 2007 (attached as Schedule "B", which begins on page 25) to reflect various updated information.

Chesapeake's Leasehold and 3-D Seismic Inventories Now Total 11.2 Million Net Acres and 16.7 Million Acres; Risked Unproved Reserves in the Company's Inventory Now Reach 18.3 Tcfe, Bringing Total Reserve Base to 27.7 Tcfe

Since 2000, Chesapeake has invested $7.1 billion in new leasehold and 3-D seismic acquisitions and now owns one of the largest inventories of onshore leasehold (11.2 million net acres) and 3-D seismic (16.7 million acres) in the U.S. On this leasehold, the company has approximately 26,500 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop an estimated 3.5 tcfe of proved undeveloped reserves and approximately 18.3 tcfe of risked unproved reserves (73 tcfe of unrisked unproved reserves). Chesapeake's 9.4 tcfe of proved reserves and its 18.3 tcfe of risked unproved reserves total approximately 27.7 tcfe.

To aggressively develop these assets, Chesapeake has continued to significantly strengthen its technical capabilities by increasing its land, geoscience and engineering staff to nearly 1,100 employees. Today, the company has over 5,000 employees, of which approximately 60% work in the company's E&P operations and approximately 40% work in the company's oilfield service operations.

Chesapeake characterizes its drilling activity by one of four play types: conventional gas resource, unconventional gas resource, emerging unconventional gas resource and 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 summarizes Chesapeake's ownership and activity in each gas resource play type and highlights notable projects in each play.

Conventional Gas Resource Plays - In its traditional conventional areas (i.e., portions of the Mid-Continent, Permian, Gulf Coast and South Texas regions), where exploration targets are typically deep and defined using 3-D seismic data, Chesapeake believes it has a meaningful competitive advantage due to its operating scale, deep drilling expertise and over 13.1 million acres of 3-D seismic data. In these plays, Chesapeake owns 3.4 million net acres on which it has an estimated 3.0 tcfe of proved developed reserves, 1.0 tcfe of proved undeveloped reserves and approximately 3.3 tcfe of risked unproved reserves and is currently using 28 operated drilling rigs to further develop its inventory of approximately 3,600 drillsites. Three of Chesapeake's most important conventional gas resource plays are described below:

-- Southern Oklahoma (generally Pennsylvanian-aged formations in Bray, Cement, Golden Trend, Sholem Alechem and Texoma): From various formations located in the Marietta, Ardmore and Anadarko Basins, the company is producing approximately 170 mmcfe net per day. The company is currently using nine operated rigs to further develop its 415,000 net acres of leasehold. Chesapeake's proved developed reserves in southern Oklahoma are an estimated 564 bcfe, its proved undeveloped reserves are an estimated 242 bcfe and its risked unproved reserves are approximately 900 bcfe after applying a 75% risk factor and assuming an additional 650 net wells are drilled in the years ahead. The company's targeted results for vertical southern Oklahoma wells are $3.5 million to develop 2.2 bcfe on approximately 120 acre spacing.

-- South Texas: Located primarily in Zapata County, Texas, Chesapeake's South Texas assets are producing approximately 145 mmcfe net per day. The company is currently using six operated rigs to further develop its 140,000 net acres of leasehold. Chesapeake's proved developed reserves in South Texas are an estimated 315 bcfe, its proved undeveloped reserves are an estimated 158 bcfe and its risked unproved reserves are approximately 300 bcfe after applying a 75% risk factor and assuming an additional 330 net wells are drilled in the years ahead. The company's targeted results for vertical South Texas wells are $2.8 million to develop 1.8 bcfe on approximately 80 acre spacing.

-- Mountain Front (primarily Morrow and Springer formations in western Oklahoma): From these prolific formations located in the Anadarko Basin, the company is producing approximately 110 mmcfe net per day. The company is currently using two operated rigs to further develop its 150,000 net acres of Mountain Front leasehold. Chesapeake's proved developed reserves in the Mountain Front area are an estimated 190 bcfe, its proved undeveloped reserves are an estimated 57 bcfe and its risked unproved reserves are approximately 250 bcfe after applying a 70% risk factor and assuming an additional 100 net wells are drilled in the years ahead. The company's targeted results for vertical Mountain Front wells are $8.0 million to develop 4.0 bcfe on approximately 320 acre spacing.

Unconventional Gas Resource Plays - In its unconventional gas resource areas, Chesapeake owns 2.7 million net acres on which it has an estimated 1.9 tcfe of proved developed reserves, 2.0 tcfe of proved undeveloped reserves and approximately 10.5 tcfe of risked unproved reserves and is currently using 83 operated drilling rigs to further develop its inventory of approximately 12,600 net drillsites. Six of Chesapeake's most important unconventional gas resource plays are described below:

-- 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 fourth largest producer of natural gas, the most active driller and the largest leasehold owner in the Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. Chesapeake is producing approximately 200 mmcfe net per day from the Fort Worth Barnett Shale. The company is currently using 28 operated rigs to further develop its 200,000 net acres of leasehold, of which 160,000 net acres are located in the Tier 1 area. By mid-year, Chesapeake expects to be using 30-35 operated rigs in the play and to be completing, on average, one new Barnett Shale well every day. Chesapeake's proved developed reserves in the Fort Worth Barnett Shale are an estimated 598 bcfe, its proved undeveloped reserves are an estimated 711 bcfe and its risked unproved reserves are approximately 3.6 tcfe after applying a 15% risk factor and assuming an additional 2,500 net wells are drilled in the years ahead. The company's targeted results for Tier 1 horizontal Fort Worth Barnett Shale wells are $2.5 million to develop 2.45 bcfe on approximately 60 acre spacing utilizing wellbores that are generally 3,000' in length and 500' apart. Chesapeake's targeted results for Tier 2 horizontal Fort Worth Barnett Shale wells are $2.25 million to develop 1.5 bcfe.

-- Fayetteville Shale (Arkansas): In this region of growing importance to Chesapeake, the company is the largest leasehold owner in the play (second largest in the core area of the play) and is producing approximately 15 mmcfe net per day. As a result of extensive analysis and successful drilling results over the last year by Chesapeake and others, the company has become more confident in the economic merits of the Fayetteville Shale play and has upgraded the play from its emerging unconventional gas resource play category. In the past two months, Chesapeake has increased its drilling activity levels more than three-fold to ten operated rigs and will increase its drilling activity level to 12 operated rigs by mid-year 2007 to further develop its 370,000 net acres of leasehold in the core area of the play. Chesapeake's proved developed reserves in the Fayetteville Shale are an estimated 34 bcfe, its proved undeveloped reserves are an estimated 55 bcfe and its risked unproved reserves are approximately 3.0 tcfe after applying a 50% risk factor to its core area acreage and assuming an additional 2,300 net wells are drilled in the years ahead. The company's targeted results for horizontal core area Fayetteville Shale wells are $2.9 million to develop 1.6 bcfe on approximately 80 acre spacing using approximately 3,000' horizontal laterals. The company is currently risking its 700,000 net acres of non-core area leasehold at 100%.

-- Sahara (primarily Mississippi, Chester, Hunton formations in Northwest Oklahoma): In this vast play that extends across five counties in northwestern Oklahoma, Chesapeake is the largest producer of natural gas, the most active driller and the largest leasehold owner in the area. Chesapeake is producing approximately 160 mmcfe net per day in the Sahara area. The company is currently using 15 operated rigs to further develop its 680,000 net acres of leasehold. Chesapeake's proved developed reserves in Sahara are an estimated 494 bcfe, its proved undeveloped reserves are an estimated 455 bcfe and its risked unproved reserves are approximately 2.4 tcfe after applying a 25% risk factor and assuming an additional 5,900 net wells are drilled in the years ahead. The company's targeted results for vertical Sahara wells are $0.9 million to develop 0.6 bcfe on approximately 70 acre spacing.

-- Deep Haley (primarily Strawn, Atoka, Morrow formations in West Texas): In this West Texas Delaware Basin area, Chesapeake is the second largest leasehold owner and the second most active driller. The company has also upgraded this play out of its emerging unconventional gas resource category following recent favorable drilling results that have increased the company's production from the Deep Haley area more than 50% over the last three months to approximately 50 mmcfe net per day. The company is currently using seven operated rigs to further develop its 260,000 net acres of leasehold. Chesapeake's proved developed reserves in Deep Haley are an estimated 61 bcfe, its proved undeveloped reserves are an estimated 60 bcfe and its risked unproved reserves are approximately 800 bcfe after applying a 75% risk factor and assuming an additional 200 net wells are drilled in the years ahead. The company's targeted results for vertical Deep Haley wells are $12.0 million to develop 6.0 bcfe on approximately 320 acre spacing.

-- Ark-La-Tex Tight Gas Sands (primarily Travis Peak, Cotton Valley, Pettit and Bossier formations): In this large region covering most of East Texas and northern Louisiana, Chesapeake has assembled a strong portfolio of unconventional gas resource plays. Chesapeake is one of the ten largest producers of natural gas, the third most active driller and one of the largest leasehold owners in the area. Chesapeake is producing approximately 130 mmcfe net per day in the Ark-La-Tex area. The company is currently using 14 operated rigs to further develop its 200,000 net acres of leasehold. Chesapeake's unconventional proved developed reserves in the Ark-La-Tex region are an estimated 365 bcfe, its proved undeveloped reserves are an estimated 310 bcfe and its unconventional risked unproved reserves are approximately 250 bcfe after applying a 70% risk factor and assuming an additional 750 net wells are drilled in the years ahead. The company's targeted results for medium-depth vertical Ark-La-Tex wells are $1.7 million to develop 1.0 bcfe on approximately 60 acre spacing.

-- Granite, Atoka and Colony Washes (western Oklahoma and Texas Panhandle): Chesapeake is the largest producer of natural gas, the most active driller and the largest leasehold owner in the various Wash plays of the Anadarko Basin. Chesapeake is producing approximately 105 mmcfe net per day from these plays. The company is currently using eight operated rigs to further develop its 150,000 net acres of leasehold. Chesapeake's proved developed reserves in the Wash plays are an estimated 298 bcfe, its proved undeveloped reserves in the Wash plays are an estimated 418 bcfe and its risked unproved reserves are approximately 400 bcfe after applying a 50% risk factor and assuming an additional 700 net wells are drilled in the years ahead. The company's targeted results for vertical Wash wells are $2.8 million to develop 1.4 bcfe on approximately 80 acre spacing.

Emerging Unconventional Gas Resource Plays - In its emerging unconventional gas resource areas where commercial production has only recently been established but the future reserve potential could be substantial, Chesapeake owns 1.5 million net acres on which it has an estimated 20 bcfe of proved developed reserves, 20 bcfe of proved undeveloped reserves and approximately 2.0 tcfe of risked unproved reserves and is currently using eight operated drilling rigs to further develop its inventory of approximately 900 net drillsites. Three of Chesapeake's most important emerging unconventional gas resource plays are described below:

-- Delaware Basin Shales (primarily Barnett and Woodford formations in West Texas): Chesapeake's most significant land acquisition activities during 2006 took place in the Delaware Basin Barnett and Woodford Shale plays in far West Texas where Chesapeake is now the largest leasehold owner. The company is producing approximately 1 mmcfe net per day from the Delaware Basin Barnett and Woodford Shales. The company is currently using four operated rigs to further develop its 680,000 net acres of leasehold. Chesapeake's proved developed reserves in the Delaware Basin shales are an estimated 1 bcfe and it has not yet booked any proved undeveloped reserves, although its risked unproved reserves are an estimated 1.0 tcfe after applying a 90% risk factor and assuming an additional 425 net wells are drilled in the years ahead. The company's targeted results for Delaware Basin vertical Barnett and Woodford Shale wells are $4.5 million to develop 3.0 bcfe on approximately 160 acre spacing. The company has not yet developed a model for targeted results from horizontal wells in the play.

-- Woodford Shale (southeastern Oklahoma Arkoma Basin): Chesapeake is the second largest leasehold owner in the Woodford Shale play, an unconventional gas play in the southeastern Oklahoma portion of the Arkoma Basin. The company is producing approximately 10 mmcfe net per day from the Woodford Shale. The company is currently using three operated rigs to further develop its 100,000 net acres of leasehold. Chesapeake's proved developed reserves in the Woodford Shale are an estimated 17 bcfe, its proved undeveloped reserves in the play are an estimated 17 bcfe and its risked unproved reserves are approximately 500 bcfe after applying a 50% risk factor and assuming an additional 300 net wells are drilled in the years ahead. The company's targeted results for horizontal Woodford Shale wells are $4.3 million to develop 2.2 bcfe on approximately 160 acre spacing.

-- Deep Bossier (East Texas and northern Louisiana): Chesapeake is one of the top three leasehold owners in the Deep Bossier play. The company is producing approximately 3 mmcfe net per day in the Deep Bossier play. The company is currently using one operated rig and plans to increase its operated rig count to six rigs by year-end 2007 to further develop its 350,000 net acres of leasehold. Chesapeake's proved developed reserves in the Deep Bossier are an estimated 3 bcfe, its proved undeveloped reserves are an estimated 3 bcfe and its risked unproved reserves are approximately 400 bcfe after applying a 90% risk factor and assuming an additional 100 net wells are drilled in the years ahead. The company's targeted results for vertical Deep Bossier wells are $10.0 million to develop 5.0 bcfe on approximately 320 acre spacing.

Appalachian Basin Gas Resource Plays - Chesapeake's Appalachia play types include conventional, unconventional and emerging unconventional in the Devonian Shale and other formations. Chesapeake is the largest leasehold owner in the region with 3.6 million net acres and is producing approximately 133 mmcfe net per day. The company is currently using a range of 7-12 operated rigs to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 978 bcfe of proved developed reserves, an estimated 528 bcfe of proved undeveloped reserves and its risked unproved reserves are approximately 2.5 tcfe after applying a 35% risk factor and assuming an additional 9,300 net wells are drilled in the years ahead. The company's targeted results for vertical Devonian Shale wells are $0.5 million to develop 0.35 bcfe on approximately 160 acre spacing.

In addition, Chesapeake continues to actively generate new prospects and acquire additional leasehold throughout the company's areas of operation in various conventional, unconventional and emerging unconventional plays not described above.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report outstanding financial and operational results for the 2007 first quarter. The company delivered attractive production and reserve growth and generated impressive profit margins that were enhanced by the company's well-executed hedging strategy. Our focused business strategy, value-added growth, tremendous inventory of undrilled locations and valuable hedge positions clearly differentiate Chesapeake in the industry.

We are pleased to again be recognized by Fortune this year as one the fastest growing and most profitable companies among the country's 500 largest corporations. In the magazine's recent Fortune 500 survey, we were ranked #325 by revenues (up from #451 last year - the third largest ranking increase in the survey), #96 by net income, #25 by earnings per share growth over the last ten years and #14 by profits as a percentage of revenues. Additionally, Chesapeake was recognized in this year's Forbes Global 2000 listing as one of the 500 largest companies in the world based on sales, profits, assets and market value.

We look forward to another successful year in 2007 as our shift in focus from resource inventory capture to resource inventory conversion continues to generate impressive results and create substantial shareholder value. Through the industry's most active drilling program, we plan to increase our average daily production rate by 14-18% in 2007 and we expect to exceed 10 tcfe of proved reserves by year-end 2007. The Fort Worth Barnett Shale play will be the largest contributor to the company's 2007 success and we are also pleased with our recent progress in the Fayetteville Shale and Deep Haley plays. Furthermore, the combination of attractive natural gas prices with decreasing oilfield service costs may well make 2007 a golden year of value creation for Chesapeake and the E&P industry.

Looking forward, we believe that Chesapeake is well positioned to prosper for years to come. As the debate in America intensifies about how to become more energy independent in an increasingly dangerous world and at the same time reduce greenhouse gas emissions in a growing economy, natural gas is emerging as the most practical solution to the challenge at hand. The vast majority of greenhouse gas emissions are caused by transportation vehicles burning gasoline and diesel and by power plants and factories burning coal. Today, we see policymakers promoting alternative fuels such as wind, solar, biofuels and nuclear. These are all legitimate alternatives (although some much less so than others), yet none can offer energy in great abundance at a reasonable price anytime soon. However, burning natural gas instead of gasoline, diesel or coal reduces greenhouse gas emissions by approximately 50%. We believe the evidence clearly demonstrates that natural gas is by far the most practical solution to the problem - it is abundant, affordable, reliable, clean burning and domestically produced.

For many years, natural gas has been valued at a BTU discount to oil. We believe the opportunity is now at hand for the climate change debate to lead to an increased appreciation of natural gas and a higher valuation for the superior fuel we produce. We intend to do well for our shareholders by doing well for our country and our world."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, May 4, 2007 at 9:00 a.m. EDT. The telephone number to access the conference call is 913-981-4911 and the confirmation code is 9507142. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from noon EDT, May 4, 2007 through midnight EDT on May 18, 2007. The number to access the conference call replay is 719-457-0820 and the passcode for the replay is 9507142. The conference call will also be webcast live on the Internet and can be accessed by going to Chesapeake's website at www.chkenergy.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 under "Risk Factors" in Item 1A of our 2006 annual report on Form 10-K filed with the Securities and Exchange Commission on March 1, 2007. They 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 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 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; 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 third largest independent and sixth 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.chkenergy.com.

CHESAPEAKE ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
($ in 000's, except per share data)
(unaudited)

| THREE MONTHS ENDED: | March 31, 2007 | | March 31, 2006 | |
|---|---|---|---|---|
| | $ | $/mcfe | $ | $/mcfe |
| REVENUES: | | | | |
| Oil and natural gas sales | 1,124,518 | 7.31 | 1,510,821 | 11.05 |
| Oil and natural gas marketing sales | 421,914 | 2.75 | 404,367 | 2.96 |
| Service operations revenue | 33,408 | 0.22 | 29,379 | 0.21 |
| Total Revenues | 1,579,840 | 10.28 | 1,944,567 | 14.22 |
| OPERATING COSTS: | | | | |
| Production expenses | 142,271 | 0.93 | 119,392 | 0.87 |
| Production taxes | 41,891 | 0.27 | 55,373 | 0.40 |
| General and administrative expenses | 52,397 | 0.34 | 28,791 | 0.21 |
| Oil and natural gas marketing expenses | 406,758 | 2.65 | 391,360 | 2.87 |
| Service operations expense | 21,657 | 0.14 | 14,437 | 0.11 |
| Oil and natural gas depreciation, depletion and amortization | 393,331 | 2.56 | 304,957 | 2.23 |
| Depreciation and amortization of other assets | 35,900 | 0.23 | 23,872 | 0.17 |
| Employee retirement expense | -- | -- | 54,753 | 0.40 |
| Total Operating Costs | 1,094,205 | 7.12 | 992,935 | 7.26 |
| INCOME FROM OPERATIONS | 485,635 | 3.16 | 951,632 | 6.96 |

| | | | | |
|---|---|---|---|---|
| OTHER INCOME (EXPENSE): | | | | |
| Interest and other income | 9,215 | 0.06 | 9,636 | 0.07 |
| Interest expense | (78,738) | (0.51) | (72,658) | (0.53) |
| Gain on sale of investment | -- | -- | 117,396 | 0.86 |
| Total Other Income (Expense) | (69,523) | (0.45) | 54,374 | 0.40 |
| INCOME BEFORE INCOME TAXES | 416,112 | 2.71 | 1,006,006 | 7.36 |
| Income Tax Expense: | | | | |
| Current | -- | -- | -- | -- |
| Deferred | 158,123 | 1.03 | 382,283 | 2.80 |
| Total Income Tax Expense | 158,123 | 1.03 | 382,283 | 2.80 |
| NET INCOME | 257,989 | 1.68 | 623,723 | 4.56 |
| Preferred stock dividends | (25,836) | (0.17) | (18,812) | (0.13) |
| Loss on exchange/conversion of preferred stock | -- | -- | (1,009) | (0.01) |
| NET INCOME AVAILABLE TO COMMON SHAREHOLDERS | 232,153 | 1.51 | 603,902 | 4.42 |

| | | |
|---|---|---|
| EARNINGS PER COMMON SHARE: | | |
| Basic | $0.51 | $1.64 |
| Assuming dilution | $0.50 | $1.44 |
| WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's) | | |
| Basic | 451,349 | 368,625 |
| Assuming dilution | 516,391 | 431,455 |

CHESAPEAKE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(in 000's)
(unaudited)

| | March 31, 2007 | December 31, 2006 |
|---|---|---|
| Cash | $3,576 | $2,519 |
| Other current assets | 1,219,084 | 1,151,350 |
| Total Current Assets | 1,222,660 | 1,153,869 |
| Property and equipment (net) | 23,397,849 | 21,904,043 |

| | | |
|---|---|---|
| Other assets | 1,111,833 | 1,359,255 |
| Total Assets | $25,732,342 | $24,417,167 |
| Current liabilities | $2,179,921 | $1,889,809 |
| Long-term debt, net | 8,371,323 | 7,375,548 |
| Asset retirement obligation | 201,000 | 192,772 |
| Other long-term liabilities | 529,755 | 390,108 |
| Deferred tax liability | 3,373,314 | 3,317,459 |
| Total Liabilities | 14,655,313 | 13,165,696 |
| Stockholders' Equity | 11,077,029 | 11,251,471 |
| Total Liabilities & Stockholders' Equity | $25,732,342 | $24,417,167 |
| Common Shares Outstanding | 460,479 | 457,434 |

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION
(in 000's)
(unaudited)

| | March 31, 2007 | % of Total Book Capitalization | December 31, 2006 | % of Total Book Capitalization |
|---|---|---|---|---|
| Long-term debt, net | $8,371,323 | 43% | $7,375,548 | 40% |
| Stockholders' equity | 11,077,029 | 57% | 11,251,471 | 60% |
| Total | $19,448,352 | 100% | $18,627,019 | 100% |

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2007 ADDITIONS TO OIL AND NATURAL GAS PROPERTIES
($ in 000's, except per unit amounts)
(unaudited)

| | Cost | Reserves (in mmcfe) | $/mcfe |
|---|---|---|---|
| Exploration and development costs | $1,066,277 | 400,680 (a) | $2.66 |
| Acquisition of proved properties | 207,585 | 93,726 | $2.21 |
| Subtotal | 1,273,862 | 494,406 | $2.58 |
| Divestitures | (208) | (1) | |
| Geological and geophysical costs | 50,371 | -- | |
| Adjusted subtotal | 1,324,025 | 494,405 | $2.68 |
| Revisions - price | -- | 135,120 | |
| Acquisition of unproved properties | 257,835 | -- | |
| Leasehold acquisition costs | 147,519 | -- | |
| Adjusted subtotal | 1,729,379 | 629,525 | $2.75 |

| | | | |
|---|---|---|---|
| Tax basis step-up | 7,186 | -- | |
| Asset retirement obligation | 4,815 | -- | |
| Total | $1,741,380 | 629,525 | $2.77 |

(a) Includes positive performance revisions of 205 bcfe and excludes upward revisions of 135 bcfe resulting from oil and natural gas price increases between December 31, 2006 and March 31, 2007.

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

| | Mmcfe |
|---|---|
| Beginning balance, 01/01/07 | 8,955,614 |
| Extensions and discoveries | 196,117 |
| Acquisitions | 93,726 |
| Revisions - performance | 204,563 |
| Revisions - price | 135,120 |
| Production | (153,650) |
| Divestitures | (1) |
| Ending balance, 03/31/07 | 9,431,489 |
| Reserve replacement | 629,525 |
| Reserve replacement ratio (a) | 410% |

(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 imbed 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: | March 31, 2007 | March 31, 2006 |
|---|---|---|
| Oil and Natural Gas Sales ($ in thousands): | | |
| Oil sales | $113,153 | $124,667 |
| Oil derivatives - realized gains (losses) | 17,848 | (3,808) |
| Oil derivatives - unrealized gains (losses) | (12,057) | (1,335) |
| Total Oil Sales | 118,944 | 119,524 |
| Natural gas sales | 887,989 | 940,318 |
| Natural gas derivatives - realized gains (losses) | 415,072 | 252,029 |
| Natural gas derivatives - unrealized gains (losses) | (297,487) | 198,950 |

| | | |
|---|---|---|
| Total Natural Gas Sales | 1,005,574 | 1,391,297 |
| Total Oil and Natural Gas Sales | $1,124,518 | $1,510,821 |
| Average Sales Price (excluding gains (losses) on derivatives): | | |
| Oil ($ per bbl) | $52.80 | $58.92 |
| Natural gas ($ per mcf) | $6.31 | $7.58 |
| Natural gas equivalent ($ per mcfe) | $6.52 | $7.79 |
| Average Sales Price (excluding unrealized gains (losses) on derivatives): | | |
| Oil ($ per bbl) | $61.13 | $57.12 |
| Natural gas ($ per mcf) | $9.26 | $9.61 |
| Natural gas equivalent ($ per mcfe) | $9.33 | $9.60 |
| Interest Expense ($ in thousands) | | |
| Interest | $76,076 | $72,898 |
| Derivatives - realized (gains) losses | 1,496 | (1,244) |
| Derivatives - unrealized (gains) losses | 1,166 | 1,004 |
| Total Interest Expense | $78,738 | $72,658 |

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA
(in 000's)
(unaudited)

| THREE MONTHS ENDED: | March 31, 2007 | March 31, 2006 |
|---|---|---|
| Beginning cash | $2,519 | $60,027 |
| Cash provided by operating activities | 976,532 | 967,458 |
| Cash (used in) investing activities | (1,869,131) | (1,960,061) |
| Cash provided by financing activities | 893,656 | 970,862 |
| Ending cash | $3,576 | $38,286 |

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF OPERATING CASH FLOW AND EBITDA
(in 000's)
(unaudited)

| THREE MONTHS ENDED: | March 31, 2007 | December 31, 2006 | March 31, 2006 |
|---|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $976,532 | $1,861,055 | $967,458 |
| Adjustments: | | | |
| Changes in assets and liabilities | 146,979 | (765,578) | 79,405 |
| OPERATING CASH FLOW(a) | $1,123,511 | $1,095,477 | $1,046,863 |

(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: | March 31, 2007 | December 31, 2006 | March 31, 2006 |
|---|---|---|---|
| NET INCOME | $257,989 | $471,362 | $623,723 |
| Income tax expense | 158,123 | 288,900 | 382,283 |
| Interest expense | 78,738 | 80,496 | 72,658 |
| Depreciation and amortization of other assets | 35,900 | 30,189 | 23,872 |
| Oil and natural gas depreciation, depletion and amortization | 393,331 | 381,680 | 304,957 |
| EBITDA(b) | $924,081 | $1,252,627 | $1,407,493 |

(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: | March 31, 2007 | December 31, 2006 | March 31, 2006 |
|---|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $976,532 | $1,861,055 | $967,458 |
| Changes in assets and liabilities | 146,979 | (765,578) | 79,405 |
| Interest expense | 78,738 | 80,496 | 72,658 |
| Unrealized gains on oil and natural gas derivatives | (309,544) | 42,905 | 197,615 |
| Other non-cash items | 31,376 | 33,749 | 90,357 |
| EBITDA | $924,081 | $1,252,627 | $1,407,493 |

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON SHAREHOLDERS

($ in 000's, except per share amounts)
(unaudited)

| THREE MONTHS ENDED: | March 31, 2007 | December 31, 2006 | March 31, 2006 |
|---|---|---|---|
| Net income available to common shareholders | $232,153 | $445,510 | $603,902 |
| Adjustments: | | | |
| Unrealized (gains) losses on derivatives, net of tax | 192,640 | (27,142) | (121,899) |
| Loss on conversion/exchange of preferred stock | -- | -- | 1,009 |
| Employee retirement expense, net of tax | -- | -- | 33,947 |
| Gain on sale of investment, net of tax | -- | -- | (72,786) |
| Adjusted net income available to common shareholders(1) | 424,793 | 418,368 | 444,173 |
| Preferred dividends | 25,836 | 25,852 | 18,812 |
| Total adjusted net income | $450,629 | $444,220 | $462,985 |
| Weighted average fully diluted shares outstanding(2) | 516,391 | 491,000 | 431,723 |
| Adjusted earnings per share assuming dilution | $0.87 | $0.90 | $1.07 |

(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 includes shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in 000's)
(unaudited)

| THREE MONTHS ENDED: | March 31, 2007 | December 31, 2006 | March 31, 2006 |
|---|---|---|---|
| EBITDA | $924,081 | $1,252,627 | $1,407,493 |
| Adjustments, before tax: | | | |

| | | | |
|---|---|---|---|
| Unrealized (gains) losses on oil and natural gas derivatives | 309,544 | (42,905) | (197,615) |
| Employee retirement expense | -- | -- | 54,753 |
| Gain on sale of investment | -- | -- | (117,396) |
| Adjusted ebitda(1) | $1,233,625 | $1,209,722 | $1,147,235 |

(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.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF MAY 3, 2007

Quarter Ending June 30, 2007; Year Ending December 31, 2007; and Year Ending December 31, 2008.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of May 3, 2007, we are using the following key assumptions in our projections for the second quarter of 2007, the full-year 2007 and the full-year 2008.

The primary changes from our February 22, 2007 Outlook are in italicized bold in the table and are explained as follows:

1) We have provided our first guidance for the quarter ending June 30, 2007;

2) We have updated the projected effect of changes in our hedging positions; and

3) Production, certain costs and capital expenditure assumptions have been updated.

| | Quarter Ending 6/30/2007 | Year Ending 12/31/2007 | Year Ending 12/31/2008 |
|---|---|---|---|
| Estimated Production | | | |
| Oil - mbbls | 2,100 | 8,500 | 8,500 |
| Natural gas - bcf | 145.5 - 149.5 | 614 - 624 | 696 - 706 |
| Natural gas equivalent - bcfe | 158 - 162 | 665 - 675 | 747 - 757 |
| Daily natural gas equivalent midpoint - in mmcfe | 1,758 | 1,836 | 2,055 |
| NYMEX Prices (a) (for calculation of realized hedging effects only): | | | |
| Oil - $/bbl | $56.25 | $56.73 | $56.25 |
| Natural gas - $/mcf | $7.52 | $7.32 | $7.50 |
| Estimated Realized Hedging Effects (based on assumed NYMEX prices above): | | | |
| Oil - $/bbl | $12.08 | $11.28 | $12.43 |
| Natural gas - $/mcf | $1.23 | $1.78 | $1.43 |
| Estimated Differentials to NYMEX Prices: | | | |
| Oil - $/bbl | 6 - 8% | 6 - 8% | 6 - 8% |

| | | | |
|---|---|---|---|
| Natural gas - $/mcf | 8 - 12% | 9 - 13% | 9 - 13% |
| Operating Costs per Mcfe of Projected Production: | | | |
| Production expense | $0.90 - 1.00 | $0.90 - 1.00 | $0.90 - 1.00 |
| Production taxes (generally 6.0% of O&G revenues) (b) | $0.41 - 0.46 | $0.41 - 0.46 | $0.41 - 0.46 |
| General and administrative | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 |
| Stock-based compensation (non-cash) | $0.08 - 0.10 | $0.08 - 0.10 | $0.10 - 0.12 |
| DD&A of oil and natural gas assets | $2.54 - 2.60 | $2.40 - 2.60 | $2.50 - 2.70 |
| Depreciation of other assets | $0.24 - 0.28 | $0.24 - 0.28 | $0.28 - 0.32 |
| Interest expense(c) | $0.55 - 0.60 | $0.60 - 0.65 | $0.60 - 0.65 |
| Other Income per Mcfe: | | | |
| Oil and natural gas marketing income | $0.06 - 0.08 | $0.06 - 0.08 | $0.06 - 0.08 |
| Service operations income | $0.08 - 0.12 | $0.08 - 0.12 | $0.08 - 0.12 |
| Book Tax Rate (About Equals 95% deferred) | 38% | 38% | 38% |
| Equivalent Shares Outstanding - in millions: | | | |
| Basic | 452 | 453 | 458 |
| Diluted | 517 | 519 | 524 |
| Capital Expenditures - in millions: | | | |
| Drilling, leasehold and seismic | $1,200 -1,300 | $5,000 - 5,200 | $5,000 -5,200 |

(a) Oil NYMEX prices have been updated for actual contract prices through March 2007 and natural gas NYMEX prices have been updated for actual contract prices through April 2007.

(b) Severance tax per mcfe is based on NYMEX prices of $56.25 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during Q2 2007, $56.73 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during calendar 2007 and $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2008.

(c) 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, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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) Basis protection swaps are arrangements that guarantee a price differential of oil or natural gas from a specified delivery point. 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.

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 non-qualifying 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q2 | 67.2 | $8.05 | 147.5 | 46% | $111.5 | $0.76 |
| Q3 | 74.9 | $8.28 | 158.0 | 47% | $105.4 | $0.67 |
| Q4 | 84.5 | $8.99 | 172.5 | 49% | $116.8 | $0.68 |
| Q2-Q4 2007(1) | 226.6 | $8.48 | 478.0 | 47% | $333.7 | $0.70 |
| Total 2008(1) | 408.7 | $9.31 | 701.0 | 58% | $105.0 | $0.15 |
| Total 2009(1) | 79.4 | $9.21 | 750.0 | 11% | $3.9 | $0.01 |

(1) Certain hedging arrangements include swaps with knockout prices ranging from $5.25 to $6.50 covering 152 bcf in Q2-Q4 2007, $5.75 to $6.50 covering 189 bcf in 2008 and $5.90 to $6.25 covering 79 bcf in 2009.

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

| | Open Swaps in Bcf's | Avg. NYMEX Floor Price | Avg. NYMEX Ceiling Price | Assuming Natural Gas Production in Bcf's of: | Open Swap Positions as a % of Estimated Total Natural Gas Production |
|---|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| 2007: | | | | | |
| Q2 | 21.8 | $6.76 | $8.20 | 147.5 | 15% |
| Q3 | 22.1 | $6.76 | $8.20 | 158.0 | 14% |
| Q4 | 19.6 | $7.13 | $8.88 | 172.5 | 11% |
| Q2-Q4 2007(1) | 63.5 | $6.88 | $8.41 | 478.0 | 13% |
| Total 2008(1) | 26.8 | $7.41 | $9.40 | 701.0 | 4% |
| Total 2009(1) | 18.3 | $7.50 | $10.72 | 750.0 | 2% |

(1) Certain collar arrangements include knockout prices ranging from $5.00 to $6.00 covering 52 bcf in Q2-Q4 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $6.00 covering 18 bcf in 2009.

Note: Not shown above are written call options covering 63.3 bcf of production in Q2-Q4 2007 at a weighted average price of $9.48 for a weighted average premium of $0.54, 104.0 bcf of production in 2008 at a weighed average price of $10.39 for a weighted average premium of $0.68 and 53.8 bcf of production in 2009 at a weighed average price of $11.51 for a weighted average premium of $0.50.

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): |
| Q2-Q4 2007 | 136.4 | 0.44 | 27.5 | 0.35 |
| 2008 | 118.6 | 0.27 | 36.6 | 0.35 |
| 2009 | 86.6 | 0.29 | 25.6 | 0.31 |
| Totals | 341.6 | $0.35 | 89.7 | $0.34 |

(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 ($293 million as of March 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q2 | 10.5 | $4.82 | $8.48 | ($3.66) | 147.5 | 7% |
| Q3 | 10.6 | $4.82 | $8.45 | ($3.63) | 158.0 | 7% |
| Q4 | 10.6 | $4.82 | $8.87 | ($4.05) | 172.5 | 6% |
| Q2-Q4 2007 | 31.7 | $4.82 | $8.60 | ($3.78) | 478.0 | 7% |
| Total 2008 | 38.4 | $4.68 | $8.02 | ($3.34) | 701.0 | 5% |
| Total 2009 | 18.3 | $5.18 | $7.28 | ($2.10) | 750.0 | 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q2 | 1,638 | $71.22 | 2,140 | 77% | $2.1 | $0.98 |
| Q3 | 1,656 | $71.61 | 2,140 | 77% | $2.1 | $0.99 |
| Q4 | 1,656 | $71.57 | 2,145 | 77% | $2.1 | $0.98 |
| Q2-Q4 2007(1) | 4,950 | $71.47 | 6,425 | 77% | $6.3 | $0.98 |
| Total 2008(1) | 6,130 | $72.61 | 8,500 | 72% | $4.8 | $0.57 |
| Total 2009(1) | 1,643 | $75.41 | 8,500 | 19% | -- | -- |

(1) Certain hedging arrangements include swaps with knockout prices ranging from $45.00 to $60.00 covering 2,200 mbbls in Q2-Q4 2007, 2,928 mbbls in 2008 and 1,460 mbbls in 2009.

Note: Not shown above are written call options covering 732 mbbls of production in 2008 at a weighted average price of $75.00 for a weighted average premium of $4.90 and 730 mbbls of production in 2009 at a weighed average price of $75.00 for a weighted average premium of $5.90.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF FEBRUARY 22, 2007

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF MAY 3, 2007

Quarter Ending March 31, 2007; Year Ending December 31, 2007; and Year Ending December 31, 2008.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of February 22, 2007, we are using the following key assumptions in our projections for the first quarter of 2007, the full-year 2007 and the full-year 2008.

The primary changes from our December 11, 2006 Outlook are in italicized bold in the table and are explained as follows:

1) We have updated the projected effect of changes in our hedging positions; and

2) Production, certain costs and capital expenditure assumptions have been updated.

| | Quarter Ending 3/31/2007 | Year Ending 12/31/2007 | Year Ending 12/31/2008 |
|---|---|---|---|
| Estimated Production | | | |
| Oil - mbbls | 2,100 | 8,500 | 8,500 |
| Natural gas - bcf | 138 - 140 | 614 - 624 | 696 - 706 |
| Natural gas equivalent - bcfe | 150.5 - 152.5 | 665 - 675 | 747 - 757 |
| Daily natural gas equivalent midpoint - in mmcfe | 1,683 | 1,836 | 2,055 |
| NYMEX Prices (a) (for calculation of realized hedging effects only): | | | |
| Oil - $/bbl | $55.62 | $56.09 | $56.25 |
| Natural gas - $/mcf | $6.76 | $7.32 | $7.50 |
| Estimated Realized Hedging Effects (based on assumed NYMEX prices above): | | | |
| Oil - $/bbl | $9.82 | $9.88 | $8.00 |
| Natural gas - $/mcf | $3.05 | $1.77 | $1.35 |
| Estimated Differentials to NYMEX Prices: | | | |
| Oil - $/bbl | 6 - 8% | 6 - 8% | 6 - 8% |
| Natural gas - $/mcf | 8 - 12% | 9 - 13% | 9 - 13% |
| Operating Costs per Mcfe of Projected Production: | | | |
| Production expense | $0.85 - 0.95 | $0.90 - 1.00 | $0.90 - 1.00 |
| Production taxes (generally 6.0% of O&G revenues) (b) | $0.41 - 0.46 | $0.41 - 0.46 | $0.41 - 0.46 |
| General and administrative | $0.20 - 0.25 | $0.20 - 0.25 | $0.22 - 0.27 |
| Stock-based compensation (non-cash) | $0.08 - 0.10 | $0.08 - 0.10 | $0.08 - 0.10 |
| DD&A of oil and natural gas assets | $2.40 - 2.60 | $2.40 - 2.60 | $2.50 - 2.70 |
| Depreciation of other assets | $0.22 - 0.24 | $0.24 - 0.28 | $0.28 - 0.32 |
| Interest expense(c) | $0.55 - 0.60 | $0.60 - 0.65 | $0.60 - 0.65 |

| | | | |
|---|---|---|---|
| Other Income per Mcfe: | | | |
| Oil and natural gas marketing income | $0.06 - 0.08 | $0.06 - 0.08 | $0.06 - 0.08 |
| Service operations income | $0.08 - 0.12 | $0.08 - 0.12 | $0.08 - 0.12 |
| Book Tax Rate (About Equals 95% deferred) | 38% | 38% | 38% |
| Equivalent Shares Outstanding - in millions: | | | |
| Basic | 452 | 453 | 458 |
| Diluted | 518 | 519 | 524 |
| Capital Expenditures - in millions: | | | |
| Drilling, leasehold and seismic | $1,100 -1,200 | $4,700 - 4,900 | $4,700 -4,900 |

(a) Oil NYMEX prices have been updated for actual contract prices through January 2007 and natural gas NYMEX prices have been updated for actual contract prices through February 2007.

(b) Severance tax per mcfe is based on NYMEX prices of $55.62 per bbl of oil and $7.40 to $8.40 per mcf of natural gas during Q1 2007, $56.09 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2007 and $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2008.

(c) 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, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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) Basis protection swaps are arrangements that guarantee a price differential of oil or natural gas from a specified delivery point. 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.

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 non-qualifying 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q1 | 33.6 | $9.33 | 139.0 | 24% | $281.1 | $2.02 |
| Q2 | 63.5 | $7.99 | 147.5 | 43% | $113.7 | $0.77 |
| Q3 | 74.9 | $8.19 | 159.0 | 47% | $103.8 | $0.65 |
| Q4 | 83.2 | $8.96 | 173.5 | 48% | $116.3 | $0.67 |
| Total 2007(1) | 255.2 | $8.54 | 619.0 | 41% | $614.9 | $0.99 |
| Total 2008(1) | 378.7 | $9.32 | 701.0 | 54% | $105.0 | $0.15 |
| Total 2009(1) | 35.6 | $8.25 | 750.0 | 5% | $3.9 | $0.01 |

(1) Certain hedging arrangements include swaps with knockout prices ranging from $5.25 to $6.50 covering 146 bcf in 2007, $5.75 to $6.50 covering 160 bcf in 2008 and $5.90 to $6.25 covering 36 bcf in 2009.

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

| | Open Swaps in Bcf's | Avg. NYMEX Floor Price | Avg. NYMEX Ceiling Price | Assuming Natural Gas Production in Bcf's of: | Open Swap Positions as a % of Estimated Total Natural Gas Production |
|---|---|---|---|---|---|
| 2007: | | | | | |
| Q1 | -- | -- | -- | 139.0 | 0% |
| Q2 | 21.8 | $6.76 | $8.20 | 147.5 | 15% |
| Q3 | 22.1 | $6.76 | $8.20 | 159.0 | 14% |
| Q4 | 19.6 | $7.13 | $8.88 | 173.5 | 11% |
| Total 2007(1) | 63.5 | $6.88 | $8.41 | 619.0 | 10% |
| Total 2008(1) | 21.3 | $7.38 | $9.20 | 701.0 | 3% |

(1) Certain collar arrangements include knockout prices ranging from $5.00 to $6.00 covering 52 bcf in

2007 and $5.00 to $6.00 covering 11 bcf in 2008.

Note: Not shown above are written call options covering 64.4 bcf of production in 2007 at a weighted average price of $9.56 for a weighted average premium of $0.54, 93.0 bcf of production in 2008 at a weighed average price of $10.20 for a weighted average premium of $0.70 and 42.9 bcf of production in 2009 at a weighed average price of $11.41 for a weighted average premium of $0.50.

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): |
| 2007 | 176.6 | 0.43 | 36.5 | 0.35 |
| 2008 | 118.6 | 0.27 | 36.6 | 0.35 |
| 2009 | 86.6 | 0.29 | 18.2 | 0.31 |
| Totals | 381.8 | $0.35 | 91.3 | $0.34 |

(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 ($357 million as of December 31, 2006). 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q1 | 10.3 | $4.82 | $10.97 | ($6.15) | 139.0 | 7% |
| Q2 | 10.5 | $4.82 | $8.48 | ($3.66) | 147.5 | 7% |
| Q3 | 10.6 | $4.82 | $8.45 | ($3.63) | 159.0 | 7% |
| Q4 | 10.6 | $4.82 | $8.87 | ($4.05) | 173.5 | 6% |
| Total 2007(1) | 42.0 | $4.82 | $9.18 | ($4.36) | 619.0 | 7% |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total 2008(1) | 38.4 | $4.68 | $8.02 | ($3.34) | 701.0 | 5% |
| Total 2009 | 18.3 | $5.18 | $7.28 | ($2.10) | 750.0 | 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q1 | 1,173 | $71.98 | 2,095 | 56% | $2.5 | $1.19 |
| Q2 | 1,274 | $72.12 | 2,120 | 60% | $2.1 | $0.99 |
| Q3 | 1,288 | $71.89 | 2,140 | 60% | $2.1 | $0.99 |
| Q4 | 1,288 | $71.61 | 2,145 | 60% | $2.1 | $0.98 |
| Total 2007(1) | 5,023 | $71.90 | 8,500 | 59% | $8.8 | $1.04 |
| Total 2008(1) | 4,300 | $71.63 | 8,500 | 51% | $4.8 | $0.57 |
| Total 2009(1) | 183 | $66.10 | 8,500 | 2% | -- | -- |

(1) Certain hedging arrangements include swaps with knockout prices ranging from $45.00 to $60.00 covering 1,460 mbbls in 2007 and $45.00 to $60.00 covering 1,098 mbbls in 2008.

SOURCE: Chesapeake Energy Corporation

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