**NEWS RELEASE**

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

Company Reports Net Income Available to Common Shareholders of $346 Million on Revenue of $2.0 Billion and Adjusted Net Income Available to Common Shareholders of $330 Million Production of 2.026 Bcfe per Day Increases 8% Sequentially and 27% Year Over Year; Proved Reserves Reach Record Level of 10.6 Tcfe; Company Delivers Year-to-Date Proved Reserve Replacement Rate of 415% from 1.606 Tcfe of Additions

OKLAHOMA CITY--(BUSINESS WIRE)--Nov. 6, 2007--Chesapeake Energy Corporation (NYSE:CHK) today reported financial and operating results for the third quarter of 2007. For the quarter, Chesapeake generated net income available to common shareholders of $346 million ($0.72 per fully diluted common share), operating cash flow of $1.085 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.240 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $2.027 billion and production of 186.4 billion cubic feet of natural gas equivalent (bcfe).

The company's 2007 third-quarter net income available to common shareholders and ebitda include an unrealized after-tax mark-to-market gain of $16 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 third quarter of $330 million ($0.69 per fully diluted common share) and adjusted ebitda of $1.195 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 22 - 25 of this release.

Key Operational and Financial Statistics Summarized Below for the 2007 Third Quarter, 2007 Second Quarter and 2006 Third Quarter

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

| | Three Months Ended: | | |
|---|---|---|---|
| | 9/30/07 | 6/30/07 | 9/30/06 |
| Average daily production (in mmcfe) | 2,026 | 1,868 | 1,597 |
| Natural gas as % of total production | 91 | 92 | 91 |
| Natural gas production (in bcf) | 170.3 | 156.1 | 133.8 |
| Average realized natural gas price ($/mcf) (a) | 7.41 | 7.97 | 8.39 |
| Oil production (in mbbls) | 2,680 | 2,324 | 2,178 |
| Average realized oil price ($/bbl) (a) | 69.25 | 65.37 | 60.62 |
| Natural gas equivalent production (in bcfe) | 186.4 | 170.0 | 146.9 |
| Natural gas equivalent realized price ($/mcfe) (a) | 7.76 | 8.21 | 8.54 |
| Oil and natural gas marketing income ($/mcfe) | .10 | .11 | .09 |
| Service operations income ($/mcfe) | .06 | .07 | .13 |
| Production expenses ($/mcfe) | (.89) | (.90) | (.84) |
| Production taxes ($/mcfe) | (.30) | (.31) | (.28) |
| General and administrative costs ($/mcfe) (b) | (.23) | (.25) | (.20) |
| Stock-based compensation ($/mcfe) | (.10) | (.07) | (.06) |
| DD&A of oil and natural gas properties ($/mcfe) | (2.57) | (2.60) | (2.34) |
| D&A of other assets ($/mcfe) | (.24) | (.23) | (.18) |
| Interest expense ($/mcfe) (a) | (.52) | (.54) | (.52) |
| Operating cash flow ($ in millions) (c) | 1,085 | 1,076 | 989 |
| Operating cash flow ($/mcfe) | 5.82 | 6.33 | 6.73 |
| Adjusted ebitda ($ in millions) (d) | 1,195 | 1,167 | 1,091 |

| | | | |
|---|---|---|---|
| Adjusted ebitda ($/mcfe) | 6.41 | 6.86 | 7.43 |
| Net income to common shareholders ($ in millions) | 346 | 492 | 523 |
| Earnings per share - assuming dilution ($) | .72 | 1.01 | 1.13 |
| Adjusted net income to common shareholders ($ in millions) (e) | 330 | 342 | 373 |
| Adjusted earnings per share - assuming dilution ($) | .69 | .71 | .83 |

(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 24

(e) defined as net income available to common shareholders, as adjusted to remove the effects of certain items detailed on page 24

Oil and Natural Gas Production Sets Record for 25th Consecutive Quarter; 2007 Third-Quarter Average Daily Production Increases 8% and 27% Over Production in the 2007 Second Quarter and the 2006 Third Quarter

Daily production for the 2007 third quarter averaged 2.026 bcfe, an increase of 158 million cubic feet of natural gas equivalent (mmcfe), or 8%, over the 1.868 bcfe of daily production in the 2007 second quarter and an increase of 429 mmcfe, or 27%, over the 1.597 bcfe produced per day in the 2006 third quarter. Virtually all of the company's production growth on both a sequential and year-over-year basis was through the drillbit. Chesapeake's average daily production for the quarter consisted of 1.851 bcf of natural gas and 29,130 barrels (bbls) of oil.

Chesapeake's 2007 third-quarter production of 186.4 bcfe was an increase of 16.4 bcfe over the 170.0 bcfe of production in the 2007 second quarter and an increase of 39.5 bcfe over the 146.9 bcfe produced in the 2006 third quarter. The company's production for the quarter was comprised of 170.3 billion cubic feet of natural gas (bcf) (91% on a natural gas equivalent basis) and 2.680 million barrels of oil and natural gas liquids (mmbbls) (9% on a natural gas equivalent basis). The company's sequential and year-over-year growth rates for its natural gas production were 9% and 27%, respectively, while the company's sequential and year-over-year growth rates for its oil production were 15% and 23%, respectively. Chesapeake's production growth rates were achieved despite the curtailment of approximately 3.0 bcfe of the company's net production during September 2007.

The 2007 third quarter was Chesapeake's 25th consecutive quarter of sequential U.S. production growth. Over these 25 quarters, Chesapeake's U.S. production has increased 417%, for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 30%.

As a result of better than expected results from the company's drilling program, Chesapeake is raising its previous forecasts for total production growth for 2007 to 21-23% from 18-22% and for 2008 to 18-22% from 14-18%, while reaffirming its 12-16% production growth forecast for 2009.

Oil and Natural Gas Proved Reserves Reach Record Level of 10.6 Tcfe; Drilling and Acquisition Costs for the First Three Quarters of 2007 Average $2.10 per Mcfe as Company Adds 1.6 Tcfe for a Reserve Replacement Rate of 415%

Chesapeake began 2007 with estimated proved reserves of 8.956 trillion cubic feet of natural gas equivalent (tcfe) and ended the third quarter with 10.562 tcfe, an increase of 1.606 tcfe, or 18%. During the first three quarters of 2007, Chesapeake replaced its 510 bcfe of production with an estimated 2.116 tcfe of new proved reserves for a reserve replacement rate of 415%. Reserve replacement through the drillbit was 1.761 tcfe, or 345% of production (including 859 bcfe of positive performance revisions and 79 bcfe of positive revisions resulting from oil and natural gas price increases between December 31, 2006 and September 30, 2007) and 83% of the total increase. Reserve replacement through the acquisition of proved reserves completed during the first three quarters of 2007 was 355 bcfe, or 70% of production and 17% of the total increase.

On a per thousand cubic feet of natural gas equivalent (mcfe) basis, the company's total drilling and acquisition costs for the first three quarters of 2007 were $2.10 per mcfe (excluding costs of $245 million for seismic, $923 million for acquisition of unproved properties, $780 million to acquire new leasehold, $182 million for capitalized interest on leasehold and unproved property and $144 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 $2.17 per mcfe during the first three quarters of 2007 while reserve replacement costs through acquisitions of proved reserves were $1.75 per mcfe. Total costs incurred in oil and natural gas acquisition, exploration and development activities during the first three quarters of 2007, including seismic, unproved properties, leasehold, capitalized interest and internal costs, non-cash tax basis step-up and asset retirement obligations, were $6.5 billion. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 20 of this release.

During the first three quarters of 2007, Chesapeake continued the industry's most active drilling program and drilled 1,523 gross (1,307 net) operated wells and participated in another 1,262 gross (173 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 first three quarters of 2007, Chesapeake invested $3.1 billion in operated wells (using an average of 153 operated rigs) and $547 million in non-operated wells (using an average of 108 non-operated rigs.

As of September 30, 2007, Chesapeake's estimated future net cash flows from proved reserves, discounted at an annual rate of 10% before income taxes (PV-10) were $19.4 billion using field differential adjusted prices of $5.85 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $6.38 per mcf) and $76.76 per bbl (based on a NYMEX quarter-end price of $81.56 per bbl).

By comparison, the December 31, 2006 PV-10 of the company's proved reserves was $13.6 billion 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). Including the effect of income taxes, the standardized measure of discounted future net cash flows from proved reserves at year-end 2006 was $10.0 billion. By further comparison, the September 30, 2006 PV-10 of the company's proved reserves was $9.7 billion using field differential adjusted prices of $3.96 per mcf (based on a NYMEX quarter-end price of $4.18 per mcf) and $58.12 per bbl (based on a NYMEX quarter-end price of $62.82 per bbl).

Chesapeake's current PV-10 changes by approximately $383 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. 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, gathering systems, compressors, land and buildings, investments, long-term derivative instruments and other noncurrent assets) was $2.9 billion as of September 30, 2007, $2.8 billion as of December 31, 2006 and $2.8 billion as of September 30, 2006.

Average Realized Prices, Hedging Results and Hedging Positions Detailed

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

By comparison, average prices realized during the 2006 third quarter (including realized gains or losses from oil and natural gas derivatives, but excluding unrealized gains or losses on such derivatives) were $8.39 per mcf of natural gas and $60.62 per bbl of oil, for a realized natural gas equivalent price of $8.54 per mcfe. Realized gains from oil and natural gas hedging activities during the 2006 third quarter generated a $2.33 gain per mcf and a $4.43 loss per bbl for a 2006 third-quarter realized hedging gain of $301 million, or $2.05 per mcfe. Excluding hedging activity, Chesapeake's average realized pricing differentials to NYMEX during the 2006 third quarter were a negative $0.52 per mcf and a negative $5.43 per bbl.

The following tables compare Chesapeake's open hedge position through swaps and collars as well as gains from lifted hedges as of November 6, 2007 to those previously announced as of September 4, 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 November 6, 2007

| Quarter or Year | Natural Gas % Hedged | Natural Gas $ NYMEX | Oil % Hedged | Oil $ NYMEX |
|---|---|---|---|---|
| 2007 Q4 | 83% | 7.84 | 63% | 72.84 |
| 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 |
|---|---|---|---|
| 2007 Q4 | 11% | 7.13 | 8.88 |
| 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) |
|---|---|---|---|
| 2007 Q4 | 158 | 182.5 | 0.87 |
| 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 |

Additionally, the company has lifted a portion of its oil hedges, securing gains of $4.3 million for the fourth quarter of 2007 and for the full year 2008.

Open Swap Positions as of September 4, 2007

| Quarter or Year | Natural Gas % Hedged | Natural Gas $ NYMEX | Oil % Hedged | Oil $ NYMEX |
|---|---|---|---|---|
| 2007 Q4 | 70% | 8.83 | 66% | 71.57 |
| 2008 Q1 | 69% | 10.07 | 75% | 72.69 |
| 2008 Q2 | 75% | 8.67 | 73% | 72.56 |
| 2008 Q3 | 71% | 8.76 | 70% | 72.40 |

| | | | | |
|---|---|---|---|---|
| 2008 Q4 | 65% | 9.30 | 61% | 73.48 |
| 2008 Total | 70% | 9.18 | 69% | 72.77 |
| 2009 Total | 27% | 8.98 | 32% | 76.75 |

Open Natural Gas Collar Positions as of September 4, 2007

| Quarter or Year | % Hedged | Average Floor $ NYMEX | Average Ceiling $ NYMEX |
|---|---|---|---|
| 2007 Q4 | 11% | 7.13 | 8.88 |
| 2008 Q1 | 11% | 7.36 | 9.28 |
| 2008 Q2 | 2% | 7.50 | 9.68 |
| 2008 Q3 | 1% | 7.50 | 9.68 |
| 2008 Q4 | 1% | 7.50 | 9.68 |
| 2008 Total | 4% | 7.41 | 9.40 |
| 2009 Total | 2% | 7.50 | 10.72 |

Gains From Lifted Natural Gas Hedges as of September 4, 2007

| Quarter or Year | Total Gain ($ millions) | Assuming Natural Gas Production of: (bcf) | Gain ($ per mcf) |
|---|---|---|---|
| 2007 Q4 | 117 | 172.5 | 0.68 |
| 2008 Q1 | 41 | 174.0 | 0.23 |
| 2008 Q2 | 21 | 178.5 | 0.12 |
| 2008 Q3 | 21 | 189.5 | 0.11 |
| 2008 Q4 | 22 | 192.5 | 0.11 |
| 2008 Total | 105 | 734.5 | 0.14 |
| 2009 Total | 4 | 835.0 | 0.01 |

Certain open natural gas swap positions include knockout swaps with knockout provisions at prices ranging from $5.25 to $6.25 covering 17 bcf in the fourth quarter of 2007, $5.45 to $6.50 covering 186 bcf in 2008 and $5.45 to $6.50 covering 152 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 14 bcf in the fourth quarter of 2007, $5.00 to $6.00 covering 11 bcf in 2008 and $5.50 to $6.00 covering 27 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 $60.00 covering 0.7 mmbbls in the fourth quarter of 2007 and 3 mmbbls in 2008, and from $52.50 to $60.00 covering 7 mmbbls in 2009.

The company's updated forecasts for 2007 through 2009 are attached to this release in an Outlook dated November 6, 2007 labeled as Schedule "A", which begins on page 26. This Outlook has been changed from the Outlook dated September 4, 2007 (attached as Schedule "B", which begins on page 30) to reflect various updated information.

Chesapeake's Leasehold and 3-D Seismic Inventories Increase to 12.5 Million Net Acres and 18.5 Million Acres; Risked Unproved Reserves in the Company's Inventory Now Reach 23 Tcfe, Bringing Total Reserve Base to 34 Tcfe

Since 2000, Chesapeake has invested $8.8 billion in new leasehold and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (12.5 million net acres) and 3-D seismic (18.5 million acres) in the U.S. On this leasehold, the company has approximately 28,000 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop an estimated 3.8 tcfe of proved undeveloped reserves and approximately 23 tcfe of risked unproved reserves (90 tcfe of unrisked unproved reserves). Chesapeake's 10.6 tcfe of estimated proved reserves and its 23 tcfe of estimated risked unproved reserves total approximately 34 tcfe.

To aggressively develop these assets, Chesapeake has continued to significantly strengthen its technical capabilities by increasing its land, geoscience and engineering staff to more than 1,300 employees. Today, the company has approximately 6,000 employees, of whom 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 approximately 14.0 million acres of 3-D seismic data. Chesapeake is producing approximately 980 mmcfe net per day in conventional gas resource plays and owns 3.5 million net acres on which it has an estimated 3.0 tcfe of proved developed reserves, 0.9 tcfe of proved undeveloped reserves and approximately 3.3 tcfe of estimated risked unproved reserves. In these plays, the company is currently using 35 operated drilling rigs to further develop its inventory of approximately 3,700 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 210 mmcfe net per day. The company is currently using eight operated rigs to further develop its 335,000 net acres of leasehold. Chesapeake's proved developed reserves in southern Oklahoma are an estimated 574 bcfe, its proved undeveloped reserves are an estimated 231 bcfe and its estimated risked unproved reserves are approximately 600 bcfe after applying a 75% risk factor and assuming an additional 500 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 and Hidalgo Counties, Texas, Chesapeake's South Texas assets are producing approximately 145 mmcfe net per day. The company is currently using five operated rigs to further develop its 140,000 net acres of leasehold. Chesapeake's proved developed reserves in South Texas are an estimated 302 bcfe, its proved undeveloped reserves are an estimated 137 bcfe and its estimated risked unproved reserves are approximately 400 bcfe after applying a 75% risk factor and assuming an additional 340 net wells are drilled in the years ahead. The company's targeted results for vertical South Texas wells are $3.3 million to develop 2.0 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 100 mmcfe net per day. The company is currently using two operated rigs to further develop its 145,000 net acres of Mountain Front leasehold. Chesapeake's proved developed reserves in the Mountain Front area are an estimated 168 bcfe, its proved undeveloped reserves are an estimated 50 bcfe and its estimated risked unproved reserves are approximately 325 bcfe after applying a 70% risk factor and assuming an additional 90 net wells are drilled in the years ahead. The company's targeted results for vertical Mountain Front wells are $9.0 million to develop 5.0 bcfe on approximately 320-acre spacing.

Unconventional Gas Resource Plays - In its unconventional gas resource plays, the company is producing approximately 1.0 bcfe net per day. Chesapeake owns 3.4 million net acres in unconventional gas resource plays on which it has an estimated 2.7 tcfe of proved developed reserves, 2.4 tcfe of proved undeveloped reserves and approximately 15.3 tcfe of estimated risked unproved reserves and is currently using 96 operated drilling rigs to further develop its inventory of approximately 15,300 net drillsites. Seven 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 third-largest producer of natural gas, the most active driller and the largest leasehold owner in the Core and Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. Chesapeake is producing approximately 330 mmcfe net per day from the Fort Worth Barnett Shale. Over the past three months, Chesapeake's net production in the Fort Worth Barnett Shale play has increased by approximately 100 mmcfe per day, or 43%, as a result the company's favorably positioned leasehold and its accelerated drilling program. Chesapeake is currently using 38 operated rigs to further develop its 235,000 net acres of leasehold, of which 200,000 net acres are located in the prime Core and Tier 1 areas. At its current pace of drilling, Chesapeake expects to be completing, on average, one new Barnett Shale well approximately every 15 hours through at least 2009. Chesapeake's proved developed reserves in the Fort Worth Barnett Shale are an estimated 979 bcfe, its proved undeveloped reserves are an estimated 806 bcfe and its estimated risked unproved reserves are approximately 4.4 tcfe after applying a 15% risk factor in the Core and Tier 1 areas and a 30% risk factor in other areas and assuming an additional 2,700 net wells are drilled in the years ahead. The company has increased its targeted results for Core and Tier 1 horizontal Fort Worth Barnett Shale wells to 2.65 bcfe at a cost of $2.6 million 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 second-largest leasehold owner in the Core area of the play and is producing approximately 60 mmcfe net per day. Chesapeake's net production levels have doubled over the past three months as a result of the company's accelerated drilling program and better-than-expected well results. Chesapeake is currently using 11 operated rigs to further develop its 420,000 net acres of leasehold in the Core area of the play. Chesapeake's proved developed reserves in the Fayetteville Shale are an estimated 117 bcfe, its proved undeveloped reserves are an estimated 97 bcfe and its estimated risked unproved reserves are approximately 5.0 tcfe after applying a 40% risk factor and assuming an additional 3,100 net wells are drilled in the years ahead. The company has increased its targeted results for horizontal Fayetteville Shale wells to 2.0 bcfe at a cost of $3.0 million on approximately 80-acre spacing using approximately 3,000' horizontal laterals.

-- Sahara (primarily Mississippi, Chester and 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. Chesapeake is producing approximately 190 mmcfe net per day in the Sahara area. The company is currently using 12 operated rigs to further develop its 800,000 net acres of leasehold. Chesapeake's proved developed reserves in Sahara are an estimated 551 bcfe, its proved undeveloped reserves are an estimated 462 bcfe and its estimated risked unproved reserves are approximately 2.6 tcfe after applying a 25% risk factor and assuming an additional 7,000 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 and Morrow formations in West Texas): In this West Texas Delaware Basin area, Chesapeake is the second-largest leasehold owner and the most active driller. Chesapeake's production from Deep Haley is approximately 105 mmcfe net per day. The company is exploring on more than 1.0 million gross acres and is currently using nine operated rigs to further develop its 560,000 net acres of leasehold. Chesapeake's proved developed reserves in Deep Haley are an estimated 137 bcfe, its proved undeveloped reserves are an estimated 145 bcfe and its estimated risked unproved reserves are approximately 1.4 tcfe after applying a 80% risk factor and assuming an additional 340 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 10-largest producers of natural gas, the third most active driller and one of the largest leasehold owners in the area. Chesapeake is producing approximately 135 mmcfe net per day in the Ark-La-Tex area. The company is currently using eight operated rigs to further develop its 220,000 net acres of leasehold. Chesapeake's unconventional proved developed reserves in the Ark-La-Tex region are an estimated 393 bcfe, its proved undeveloped reserves are an estimated 257 bcfe and its estimated unconventional risked unproved reserves are approximately 325 bcfe after applying a 70% risk factor and assuming an additional 800 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 50-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 155 mmcfe net per day from these plays. The company is currently using 12 operated rigs to further develop its 190,000 net acres of Wash leasehold. Chesapeake's proved developed reserves in the Wash plays are an estimated 415 bcfe, its proved undeveloped reserves are an estimated 521 bcfe and its estimated risked unproved reserves are approximately 900 bcfe after applying a 50% risk factor and assuming an additional 750 net wells are drilled in the years ahead. The company's targeted results for vertical Granite and Atoka Wash wells are $2.8 million to develop 1.4 bcfe on approximately 80-acre spacing. The company's targeted results for horizontal Colony Wash wells are $7.0 million to develop 6.25 bcfe on approximately 160-acre spacing.

-- 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. As a result of successful drilling results by Chesapeake and others, the company has become more confident in the economic merits of a portion of the Woodford Shale play and has upgraded the play from its emerging unconventional gas resource play category. However, to high-grade its efforts in the play, Chesapeake has elected to sell approximately 65,000 net acres in a transaction anticipated to close by year-end 2007. The company is producing approximately 25 mmcfe net per day from the Woodford Shale and is currently using five operated rigs to further develop its 35,000 net acres that will remain after the sale. Chesapeake's proved developed reserves in the Woodford Shale are an estimated 44 bcfe, its proved undeveloped reserves in the play are an estimated 47 bcfe and its estimated risked unproved reserves are approximately 550 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 2.45 bcfe on approximately 160-acre spacing

Emerging Unconventional Gas Resource Plays - In its emerging unconventional gas resource plays, commercial production has only recently been established but the company believes future reserve potential could be substantial. Chesapeake is producing approximately 15 mmcfe net per day in these plays and owns 1.9 million net acres on which it has an estimated 38 bcfe of proved developed reserves, 11 bcfe of proved undeveloped reserves and approximately 2.0 tcfe of estimated risked unproved reserves. In these plays, the company is currently using seven operated drilling rigs to further develop its inventory of approximately 1,000 net drillsites. Two 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 continues to evaluate a variety of drilling and completion techniques to test the commercial potential of its Delaware Basin Barnett and Woodford Shale play in far West Texas where Chesapeake is the largest leasehold owner. The company is producing approximately 3 mmcfe net per day from the Delaware Basin Barnett and Woodford Shales. The company is currently using four operated rigs to further develop its 800,000 net acres of leasehold. Chesapeake's proved developed reserves in the Delaware Basin shales are an estimated 9 bcfe and it has not yet booked any proved undeveloped reserves. The company estimates its risked unproved reserves are 1.1 tcfe after applying a 90% risk factor and assuming an additional 500 net wells are drilled in the years ahead. The company's targeted results for Delaware Basin vertical Barnett and Woodford Shale wells are $5.5 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.

-- Deep Bossier (East Texas and northern Louisiana): Chesapeake is one of the top three leasehold owners in the Deep Bossier play and is producing approximately 7 mmcfe net per day. The company is currently using three operated rigs to further develop its 380,000 net acres of leasehold. Chesapeake's proved developed reserves in the Deep Bossier are an estimated 7 bcfe, its proved undeveloped reserves are an estimated 4 bcfe and its estimated risked unproved reserves are approximately 450 bcfe after applying a 90% risk factor and assuming an additional 120 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 Appalachian assets include both conventional and unconventional play types in the Devonian Shale and other formations. Chesapeake is the largest leasehold owner in the region with 3.8 million net acres and is producing approximately 135 mmcfe net per day. The company is currently using 13 operated rigs in the region to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 1.0 tcfe of proved developed reserves, an estimated 527 bcfe of proved undeveloped reserves and its estimated risked unproved reserves are approximately 2.8 tcfe after applying a 50% risk factor and assuming an additional 8,100 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 140-acre spacing. The company is currently drilling a series of vertical and horizontal Marcellus Shale wells and is also developing exploration programs for various deep and horizontal targets other than the Marcellus Shale.

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.

Company Provides Update on Recently Announced Enhanced Financial Plan

In early September 2007, Chesapeake announced an enhanced financial plan designed to monetize latent balance sheet value and to fully fund its planned capital expenditures through 2009 without accessing public capital markets. Since then, the company has successfully implemented multiple aspects of the plan and anticipates further progress over the next two quarters. Chesapeake believes its planned transactions in the asset and financial markets will allow it to monetize approximately $4 billion of assets by the end of 2009 that, in management's opinion, have not been adequately reflected in the company's market valuation historically.

Drilling Rig and Natural Gas Compression Sale/Leaseback Transactions - During the 2007 third quarter, Chesapeake completed its third sale/leaseback transaction on 37 drilling rigs for net proceeds of approximately $235 million. The company has now completed sale/leaseback transactions on a total of 70 rigs and anticipates completing similar transactions on its remaining 11 rigs during the fourth quarter of 2007. Also during the 2007 third quarter, Chesapeake completed a sale/leaseback facility for its natural gas compression assets. The company received approximately $160 million for the sale/leaseback of its existing natural gas compression assets and will fund up to $185 million of future natural gas compression assets under the same facility. Once the additional transactions are completed, Chesapeake estimates that virtually all of its historical cost in its 81 rig drilling fleet and its natural gas compression assets will have been monetized at a pre-tax cost of capital of approximately 5.5%.

Producing Property Monetizations and Asset Sales - The company is currently in the process of monetizing certain Chesapeake-operated producing assets in Kentucky and West Virginia. The company intends to retain drilling rights on the properties below currently producing intervals and outside of existing producing wellbores. Chesapeake has received multiple attractive offers for the Appalachian assets with a variety of transaction structures. The company anticipates completing a monetization transaction by year-end 2007 for proceeds in excess of $1.0 billion. In addition, the company also plans to pursue four more monetizations of similarly mature properties in 2008 and 2009 for further proceeds of approximately $2.0 billion. For accounting purposes, the company anticipates that the proposed transactions will be treated as prepaid sales rather than property sales.

The company is also currently in the process of selling non-core E&P assets in the Rocky Mountains and in the southeastern Oklahoma Woodford Shale play for expected proceeds in excess of $300 million. These sales are anticipated to close by the first quarter of 2008. In total, Chesapeake is anticipating receiving monetization and sale proceeds of approximately $3.3 billion by year-end 2009.

Midstream MLP - Chesapeake is currently in the process of forming a private MLP 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, which are expected to grow substantially in future years, currently generate annualized cash flow from operating activities in excess of $100 million. The company believes its MLP transaction will be valued at more than $1 billion and is anticipated to close in the first quarter of 2008.

New Revolving Credit Facility - On November 2, 2007, Chesapeake completed a new, five-year $3.0 billion Senior Secured Revolving Credit Facility that replaced the company's previous $2.5 billion facility. The new facility reflects the increased scale and scope of the company's operations and will help accommodate timing differences between operational cash flow, asset monetizations and planned capital expenditures.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report outstanding financial and operational results for the 2007 third quarter. We are particularly proud of our success through the drillbit that enabled the company to deliver reserve and production growth well above our expectations despite the impact of our 3.0 bcfe curtailment of natural gas production during the month of September in response to low natural gas prices. 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.

"The benefits of Chesapeake's strategic shift from resource capture to resource conversion that began in 2006 are noticeably accelerating and we look forward to generating further strong growth in the fourth quarter of 2007 and in 2008 and 2009. In fact, our drilling success continues to exceed our expectations and so we are once again increasing our production growth rates for 2007 to 21-23% from 18-22% and for 2008 to 18-22% from 14-18%, while reaffirming our 12-16% production growth forecast for 2009. In addition, we expect to increase our proved reserves this year by 20-25% to approximately 11 tcfe, and we are now raising our year-end 2008 reserve expectations to 12.5-13 tcfe from our previous projection of 12 tcfe and our year-end 2009 proved reserve expectation to 14-15 tcfe from 13 tcfe previously.

"Our focused business strategy, value-added growth, tremendous inventory of undrilled locations and valuable hedge positions clearly differentiate Chesapeake in the industry and we look forward to continuing to create substantial value for our shareholders as we successfully execute our business plan in the years ahead."

Conference Call Information

A conference call to discuss this release has been scheduled for Wednesday morning, November 7, 2007, at 9:00 a.m. EST. The telephone number to access the conference call from within the United States is 800-591-6945 and from outside the U.S. is 617-614-4911. The passcode for the call is 74141697. 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, November 7, 2007, through midnight EST on November 21, 2007. The number to access the conference call replay from within the U.S. is 888-286-8010 and from outside the U.S. is 617-801-6888. The passcode for the replay is 45774944. 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 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 9, 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 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.chkenergy.com.

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

| THREE MONTHS ENDED: | September 30, 2007 $ | $/mcfe | September 30, 2006 $ | $/mcfe |
|---|---|---|---|---|
| REVENUES: | | | | |
| Oil and natural gas sales | 1,492,002 | 8.00 | 1,493,226 | 10.16 |
| Oil and natural gas marketing sales | 501,268 | 2.69 | 398,114 | 2.71 |
| Service operations revenue | 33,732 | 0.18 | 38,071 | 0.26 |
| Total Revenues | 2,027,002 | 10.87 | 1,929,411 | 13.13 |
| OPERATING COSTS: | | | | |
| Production expenses | 165,334 | 0.89 | 124,045 | 0.84 |
| Production taxes | 56,160 | 0.30 | 40,562 | 0.28 |
| General and administrative expenses | 61,443 | 0.33 | 37,382 | 0.25 |
| Oil and natural gas marketing expenses | 482,990 | 2.59 | 384,473 | 2.62 |
| Service operations expense | 23,034 | 0.12 | 18,821 | 0.13 |
| Oil and natural gas depreciation, depletion and amortization | 479,035 | 2.57 | 343,723 | 2.34 |
| Depreciation and amortization of other assets | 44,418 | 0.24 | 27,016 | 0.18 |
| Total Operating Costs | 1,312,414 | 7.04 | 976,022 | 6.64 |
| INCOME FROM OPERATIONS | 714,588 | 3.83 | 953,389 | 6.49 |
| OTHER INCOME (EXPENSE): | | | | |
| Interest and other income | 1,652 | 0.01 | 5,132 | 0.03 |
| Interest expense | (116,048) | (0.62) | (74,112) | (0.50) |
| Total Other Income (Expense) | (114,396) | (0.61) | (68,980) | (0.47) |
| INCOME BEFORE INCOME TAXES | 600,192 | 3.22 | 884,409 | 6.02 |
| Income Tax Expense: | | | | |
| Current | 8,762 | 0.05 | -- | -- |
| Deferred | 219,312 | 1.17 | 336,074 | 2.29 |
| Total Income Tax Expense | 228,074 | 1.22 | 336,074 | 2.29 |

| | | | | |
|---|---|---|---|---|
| NET INCOME | 372,118 | 2.00 | 548,335 | 3.73 |
| Preferred stock dividends | (25,836) | (0.14) | (25,753) | (0.17) |
| Loss on exchange/conversion of preferred stock | -- | -- | -- | -- |
| NET INCOME AVAILABLE TO COMMON SHAREHOLDERS | 346,282 | 1.86 | 522,582 | 3.56 |

EARNINGS PER COMMON SHARE:

| | | |
|---|---|---|
| Basic | $0.76 | $1.25 |
| Assuming dilution | $0.72 | $1.13 |

WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)

| | | |
|---|---|---|
| Basic | 453,572 | 417,569 |
| Assuming dilution | 516,735 | 483,273 |

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

| NINE MONTHS ENDED: | September 30, 2007 | | September 30, 2006 | |
|---|---|---|---|---|
| | $ | $/mcfe | $ | $/mcfe |
| REVENUES: | | | | |
| Oil and natural gas sales | 4,164,044 | 8.16 | 4,190,430 | 9.83 |
| Marketing sales | 1,446,251 | 2.84 | 1,170,091 | 2.74 |
| Service operations revenue | 101,049 | 0.20 | 97,473 | 0.23 |
| Total Revenues | 5,711,344 | 11.20 | 5,457,994 | 12.80 |
| OPERATING COSTS: | | | | |
| Production expenses | 460,609 | 0.90 | 364,134 | 0.85 |
| Production taxes | 151,250 | 0.30 | 129,858 | 0.30 |
| General and administrative expenses | 168,150 | 0.33 | 99,728 | 0.23 |
| Marketing expenses | 1,394,134 | 2.73 | 1,131,521 | 2.66 |
| Service operations expense | 67,096 | 0.13 | 48,925 | 0.12 |
| Oil and natural gas depreciation, depletion and amortization | 1,314,429 | 2.58 | 976,839 | 2.29 |
| Depreciation and amortization of other assets | 120,162 | 0.24 | 74,051 | 0.17 |
| Employee retirement expense | -- | -- | 54,753 | 0.13 |
| Total Operating Costs | 3,675,830 | 7.21 | 2,879,809 | 6.75 |

| | | | | |
|---|---|---|---|---|
| INCOME FROM OPERATIONS | 2,035,514 | 3.99 | 2,578,185 | 6.05 |
| OTHER INCOME (EXPENSE): | | | | |
| Interest and other income | 12,318 | 0.02 | 19,742 | 0.04 |
| Interest expense | (278,518) | (0.54) | (220,226) | (0.52) |
| Gain on sale of investment | 82,705 | 0.16 | 117,396 | 0.28 |
| Total Other Income (Expense) | (183,495) | (0.36) | (83,088) | (0.20) |
| Income Before Income Taxes | 1,852,019 | 3.63 | 2,495,097 | 5.85 |
| Income Tax Expense: | | | | |
| Current | 19,470 | 0.04 | -- | -- |
| Deferred | 684,297 | 1.34 | 963,136 | 2.26 |
| Total Income Tax Expense | 703,767 | 1.38 | 963,136 | 2.26 |
| NET INCOME | 1,148,252 | 2.25 | 1,531,961 | 3.59 |
| Preferred stock dividends | (77,508) | (0.15) | (62,793) | (0.15) |
| Loss on exchange/conversion of preferred stock | -- | -- | (10,556) | (0.02) |
| NET INCOME AVAILABLE TO COMMON SHAREHOLDERS | 1,070,744 | 2.10 | 1,458,612 | 3.42 |
| EARNINGS PER COMMON SHARE: | | | | |
| Basic | $2.37 | | $3.75 | |
| Assuming dilution | $2.23 | | $3.40 | |
| WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's) | | | | |
| Basic | 452,368 | | 389,136 | |
| Assuming dilution | 515,563 | | 450,680 | |

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

| | September 30, 2007 | December 31, 2006 |
|---|---|---|
| Cash | $ 2,130 | $ 2,519 |
| Other current assets | 1,278,329 | 1,151,350 |
| Total Current Assets | 1,280,459 | 1,153,869 |
| Property and equipment (net) | 27,547,974 | 21,904,043 |
| Other assets | 1,060,127 | 1,359,255 |
| Total Assets | $ 29,888,560 | $ 24,417,167 |

| | | |
|---|---|---|
| Current liabilities | $ 2,390,352 | $ 1,889,809 |
| Long-term debt, net | 10,872,256 | 7,375,548 |
| Asset retirement obligation | 218,212 | 192,772 |
| Other long-term liabilities | 503,973 | 390,108 |
| Deferred tax liability | 3,900,114 | 3,317,459 |
| Total Liabilities | 17,884,907 | 13,165,696 |
| Stockholders' Equity | 12,003,653 | 11,251,471 |
| Total Liabilities & Stockholders' Equity | $ 29,888,560 | $ 24,417,167 |
| Common Shares Outstanding | 473,721 | 457,434 |

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

| | September 30, 2007 | % of Total Book Capitalization | December 31, 2006 | % of Total Book Capitalization |
|---|---|---|---|---|
| Long-term debt, net | $10,872,256 | 48 | $ 7,375,548 | 40 |
| Stockholders' equity | 12,003,653 | 52 | 11,251,471 | 60 |
| Total | $22,875,909 | 100 | $18,627,019 | 100 |

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADDITIONS TO OIL AND NATURAL GAS PROPERTIES
NINE MONTHS ENDED SEPTEMBER 30, 2007
($ in 000's, except per unit amounts)
(unaudited)

| | Cost | Reserves (in mmcfe) | $/mcfe |
|---|---|---|---|
| Exploration and development costs | $3,648,333 | 1,681,836(a) | 2.17 |
| Acquisition of proved properties | 622,517 | 354,786 | 1.75 |
| Subtotal | 4,270,850 | 2,036,622 | 2.10 |
| Divestitures | (228) | (118) | |
| Geological and geophysical costs | 245,410 | -- | |
| Adjusted subtotal | 4,516,032 | 2,036,504 | 2.22 |
| Revisions - price | -- | 79,389 | |
| Leasehold acquisition costs | 630,344 | -- | |
| Lease brokerage costs and recording fees | 150,057 | -- | |
| Acquisition of unproved properties and other | 922,979 | -- | |
| Capitalized interest on leasehold and | | | |

| | | | |
|---|---|---|---|
| unproved property | 181,555 | -- | |
| Adjusted subtotal | 6,400,967 | 2,115,893 | 3.03 |
| Tax basis step-up | 129,705 | -- | |
| Asset retirement obligation and other | 14,700 | -- | |
| Total | $6,545,372 | 2,115,893 | 3.09 |

(a) Includes positive performance revisions of 859 bcfe and excludes positive revisions of 79 bcfe resulting from oil and natural gas price increases between December 31, 2006 and September 30, 2007.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
NINE MONTHS ENDED SEPTEMBER 30, 2007
(unaudited)

| | Mmcfe |
|---|---|
| Beginning balance, 01/01/07 | 8,955,614 |
| Extensions and discoveries | 822,879 |
| Acquisitions | 354,786 |
| Divestitures | (118) |
| Revisions - performance | 858,957 |
| Revisions - price | 79,389 |
| Production | (510,079) |
| Ending balance, 9/30/07 | 10,561,428 |
| Reserve replacement | 2,115,893 |
| Reserve replacement ratio (a) | 415% |

(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
(in 000's)
(unaudited)

| | THREE MONTHS ENDED September 30, | | NINE MONTHS ENDED September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Oil and Natural Gas Sales ($ in thousands): | | | | |
| Oil sales | $ 189,635 | $ 141,687 | $ 442,460 | $ 404,595 |
| Oil derivatives - realized gains (losses) | (4,048) | (9,660) | 26,059 | (25,695) |
| Oil derivatives - unrealized gains (losses) | (27,815) | 28,724 | (54,715) | 24,825 |
| Total Oil Sales | 157,772 | 160,751 | 413,804 | 403,725 |

| | | | | |
|---|---|---|---|---|
| Natural gas sales | 971,899 | 811,591 | 2,918,541 | 2,526,168 |
| Natural gas derivatives - realized gains (losses) | 289,653 | 311,090 | 890,076 | 832,769 |
| Natural gas derivatives - unrealized gains (losses) | 72,678 | 209,794 | (58,377) | 427,768 |
| Total Natural Gas Sales | 1,334,230 | 1,332,475 | 3,750,240 | 3,786,705 |
| Total Oil and Natural Gas Sales | $1,492,002 | $1,493,226 | $4,164,044 | $4,190,430 |
| Average Sales Price - excluding gains (losses) on derivatives: | | | | |
| Oil ($ per bbl) | $ 70.76 | $ 65.05 | $ 61.91 | $ 62.85 |
| Natural gas ($ per mcf) | $ 5.71 | $ 6.06 | $ 6.25 | $ 6.52 |
| Natural gas equivalent ($ per mcfe) | $ 6.23 | $ 6.49 | $ 6.59 | $ 6.87 |
| Average Sales Price - excluding unrealized gains (losses) on derivatives): | | | | |
| Oil ($ per bbl) | $ 69.25 | $ 60.62 | $ 65.55 | $ 58.86 |
| Natural gas ($ per mcf) | $ 7.41 | $ 8.39 | $ 8.15 | $ 8.66 |
| Natural gas equivalent ($ per mcfe) | $ 7.76 | $ 8.54 | $ 8.39 | $ 8.77 |
| Interest Expense ($ in thousands): | | | | |
| Interest | $ 98,219 | $ 75,100 | $ 265,192 | $ 221,832 |
| Derivatives - realized (gains) losses | (1,314) | 1,555 | 393 | (852) |
| Derivatives - unrealized (gains) losses | 19,143 | (2,543) | 12,933 | (754) |
| Total Interest Expense | $ 116,048 | $ 74,112 | $ 278,518 | $ 220,226 |

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

| | September 30, | September 30, |
|---|---|---|
| THREE MONTHS ENDED: | 2007 | 2006 |

| | | |
|---|---|---|
| Beginning cash | $ 3,870 | $ 366,270 |
| Cash provided by operating activities | 1,266,639 | 937,275 |
| Cash (used in) investing activities | (2,484,804) | (2,883,948) |
| Cash provided by financing activities | 1,216,425 | 1,581,119 |
| Ending cash | 2,130 | 716 |

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|
| Beginning cash | $ 2,519 | $ 60,027 |
| Cash provided by operating activities | 3,388,539 | 2,982,419 |
| Cash (used in) investing activities | (6,487,841) | (6,668,005) |
| Cash provided by financing activities | 3,098,913 | 3,626,275 |
| Ending cash | 2,130 | 716 |

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

| THREE MONTHS ENDED: | September 30, 2007 | June 30, 2007 | September 30, 2006 |
|---|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $ 1,266,639 | $ 1,145,368 | $ 937,275 |
| Adjustments: | | | |
| Changes in assets and liabilities | (181,917) | (69,046) | 51,328 |
| OPERATING CASH FLOW (1) | $ 1,084,722 | $ 1,076,322 | $ 988,603 |

(1)Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of 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: | September 30, 2007 | June 30, 2007 | September 30, 2006 |
|---|---|---|---|
| NET INCOME | $ 372,118 | $ 518,145 | $ 548,335 |
| Income tax expense | 228,074 | 317,570 | 336,074 |
| Interest expense | 116,048 | 83,732 | 74,112 |
| Depreciation and amortization of other assets | 44,418 | 39,844 | 27,016 |
| Oil and natural gas depreciation, depletion and amortization | 479,035 | 442,063 | 343,723 |

| | | | |
|---|---|---|---|
| EBITDA (2) | $ 1,239,693 | $1,401,354 | $ 1,329,260 |

(2)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: | September 30, 2007 | June 30, 2007 | September 30, 2006 |
|---|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $ 1,266,639 | $ 1,145,368 | $ 937,275 |
| Changes in assets and liabilities | (181,917) | (69,046) | 51,328 |
| Interest expense | 116,048 | 83,732 | 74,112 |
| Unrealized gains (losses) on oil and natural gas derivatives | 44,863 | 151,589 | 238,518 |
| Other non-cash items | (5,940) | 89,711 | 28,027 |
| EBITDA | $ 1,239,693 | $ 1,401,354 | $ 1,329,260 |

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

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $ 3,388,539 | $ 2,982,419 |
| Adjustments: | | |
| Changes in assets and liabilities | (103,984) | (32,787) |
| OPERATING CASH FLOW (1) | $ 3,284,555 | $ 2,949,632 |

(1)Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating cash flow is presented because management believes it is a useful adjunct to net cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). Operating cash flow is widely accepted as a financial indicator of 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.

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|

| | | |
|---|---|---|
| NET INCOME | $ 1,148,252 | $ 1,531,961 |
| Income tax expense | 703,767 | 963,136 |
| Interest expense | 278,518 | 220,226 |
| Depreciation and amortization of other assets | 120,162 | 74,051 |
| Oil and natural gas depreciation, depletion and amortization | 1,314,429 | 976,839 |
| EBITDA (2) | $ 3,565,128 | $ 3,766,213 |

(2)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:

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|
| CASH PROVIDED BY OPERATING ACTIVITIES | $ 3,388,539 | $ 2,982,419 |
| Changes in assets and liabilities | (103,984) | (32,787) |
| Interest expense | 278,518 | 220,226 |
| Unrealized gains (losses) on oil and natural gas derivatives | (113,092) | 452,593 |
| Other noncash items | 115,147 | 143,762 |
| EBITDA | $ 3,565,128 | $ 3,766,213 |

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON SHAREHOLDERS
($ in 000's, except per share amounts)
(unaudited)

| THREE MONTHS ENDED: | September 30, 2007 | June 30, 2007 | September 30, 2006 |
|---|---|---|---|
| Net income available to common shareholders | $ 346,282 | $ 492,309 | $ 522,582 |
| Adjustments: | | | |
| Unrealized (gains) losses on derivatives, net of tax | (15,947) | (98,559) | (149,457) |
| Gain on sale of investment, net of tax | -- | (51,277) | -- |
| Adjusted net income available to common shareholders (1) | 330,335 | 342,473 | 373,125 |
| Preferred dividends | 25,836 | 25,836 | 25,753 |

| | | | |
|---|---|---|---|
| Total adjusted net income | $ 356,171 | $ 368,309 | $ 398,878 |
| Weighted average fully diluted shares outstanding (2) | 516,735 | 515,159 | 483,273 |
| Adjusted earnings per share assuming dilution | $ 0.69 | $ 0.71 | $ 0.83 |

(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 000's)
(unaudited)

| THREE MONTHS ENDED: | September 30, 2007 | June 30, 2007 | September 30, 2006 |
|---|---|---|---|
| EBITDA | $ 1,239,693 | $ 1,401,354 | $ 1,329,260 |
| Adjustments, before tax: | | | |
| Unrealized (gains) losses on oil and natural gas derivatives | (44,863) | (151,589) | (238,518) |
| Gain on sale of investment | -- | (82,705) | -- |
| Adjusted ebitda (1) | $ 1,194,830 | $ 1,167,060 | $ 1,090,742 |

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

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|

| | | |
|---|---|---|
| Net income available to common shareholders | $ 1,070,744 | $ 1,458,612 |
| Adjustments: | | |
| Unrealized (gains) losses on derivatives, net of tax | 78,134 | (281,076) |
| Gain on sale of investment, net of tax | (51,277) | (72,786) |
| Loss on conversion/exchange of preferred stock | -- | 10,556 |
| Employee retirement expense, net of tax | -- | 33,947 |
| Cumulative impact of income tax rate change | -- | 15,000 |
| Legal settlement, net of tax | -- | (7,192) |
| Adjusted net income available to common shareholders (1) | 1,097,601 | 1,157,061 |
| Preferred dividends | 77,508 | 62,793 |
| Total adjusted net income | $ 1,175,109 | $ 1,219,854 |
| Weighted average fully diluted shares outstanding (2) | 515,563 | 450,680 |
| Adjusted earnings per share assuming dilution | $ 2.28 | $ 2.71 |

(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 000's)
(unaudited)

| NINE MONTHS ENDED: | September 30, 2007 | September 30, 2006 |
|---|---|---|
| EBITDA | $ 3,565,128 | $ 3,766,213 |
| Adjustments, before tax: | | |
| Unrealized (gains) losses on oil and natural gas derivatives | 113,092 | (452,593) |
| Gain on sale of investment | (82,705) | (117,396) |
| Employee retirement expense | -- | 54,753 |
| Legal settlement | -- | (11,600) |
| Adjusted EBITDA (1) | $ 3,595,515 | $ 3,239,377 |

============ =============

(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 NOVEMBER 6, 2007

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 | Year Ending 12/31/2008 | Year Ending 12/31/2009 |
|---|---|---|---|---|
| Estimated Production(a) | | | | |
| Oil - mbbls | 2,500 | 9,600 | 10,500 | 11,000 |
| Natural gas - bcf | 181.5 - 183.5 | 649 - 651 | 788 - 798 | 892 - 902 |
| Natural gas equivalent - bcfe | 196.5 - 198.5 | 707 - 709 | 851 - 861 | 958 - 968 |
| Daily natural gas equivalent midpoint - in mmcfe | 2,150 | 1,940 | 2,340 | 2,640 |
| NYMEX Prices (b) (for calculation of realized hedging effects only): | | | | |
| Oil - $/bbl | $79.84 | $69.60 | $75.00 | $75.00 |
| Natural gas - $/mcf | $7.07 | $6.89 | $7.50 | $7.50 |
| Estimated Realized Hedging Effects (based on assumed NYMEX prices above): | | | | |
| Oil - $/bbl | $(5.40) | $1.28 | $(0.44) | $3.88 |
| Natural gas - $/mcf | $1.68 | $1.84 | $1.36 | $0.53 |
| Estimated Differentials to NYMEX Prices: | | | | |
| Oil - $/bbl | 7 - 9% | 7 - 9% | 7 - 9% | 7 - 9% |
| Natural gas - $/mcf | 10 - 14% | 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 | $0.90 - 1.00 |
| Production taxes (generally 5.5% of O&G revenues) (c) | $0.35 - 0.40 | $0.35 - 0.40 | $0.35 - 0.40 | $0.35 - 0.40 |
| General and administrative | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 |
| Stock-based compensation | $0.08 - | $0.08 - | $0.10 - | $0.10 - |

| | | | | |
|---|---|---|---|---|
| (non-cash) | 0.10 | 0.10 | 0.12 | 0.12 |
| DD&A of oil and natural gas assets | $2.60 - 2.70 | $2.50 - 2.70 | $2.50 - 2.70 | $2.50 - 2.70 |
| Depreciation of other assets | $0.18 - 0.20 | $0.20 - 0.24 | $0.26 - 0.30 | $0.26 - 0.30 |
| Interest expense(d) | $0.55 - 0.60 | $0.55 - 0.60 | $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 | $0.07 - 0.09 | $0.07 - 0.09 |
| Service operations income | $0.04 - 0.06 | $0.05 - 0.07 | $0.05 - 0.07 | $0.05 - 0.07 |
| Book Tax Rate (About Equals 97% deferred) | 38% | 38% | 38% | 38% |
| -------------------------- | | | | |
| Equivalent Shares Outstanding - in millions: | | | | |
| Basic | 480 | 459 | 496 | 504 |
| Diluted | 520 | 519 | 525 | 532 |
| Budgeted Capital Expenditures, net - in millions: | | | | |
| Drilling | $1,000 - 1,100 | $4,250 - 4,450 | $4,000 - 4,200 | $4,000 - 4,200 |
| Leasehold and property acquisition costs | $300 - 350 | $1,200 - 1,400 | $1,200 - 1,400 | $1,200 - 1,400 |
| Monetization of oil and gas properties(a) | $(1,000 - 1,200) | $(1,000 - 1,200) | $(1,000 - 1,200) | $(1,000 - 1,200) |
| Geological and geophysical costs | $50 - 75 | $250 - 300 | $200 - 250 | $200 - 250 |
| | ---------- | ---------- | ---------- | ---------- |
| Total budgeted capital expenditures, net | $325 - 350 | $4,700 - 4,950 | $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:

| | Open Collars in Bcf's | Avg. NYMEX Floor Price | Avg. NYMEX Ceiling Price | Assuming Natural Gas Production in Bcf's of: | Open Collars as a % of Estimated Total Natural Gas Production |
|---|---|---|---|---|---|
| Q4 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(1): | Volume in Bcf's | NYMEX plus(1): |
| 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 |

(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 ($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.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF SEPTEMBER 4, 2007

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF NOVEMBER 6, 2007

Quarters Ending September 30, 2007 and December 31, 2007; 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 September 4, 2007, we are using the following key assumptions in our projections for the third quarter of 2007, the fourth quarter of 2007 and the full-years 2007, 2008 and 2009.

The primary changes from our August 2, 2007 Outlook are in italicized bold and are explained as follows:

1) We are increasing our prior production guidance for the quarter ending September 30, 2007;

2) Guidance for the quarter ending December 31, 2007 has been provided for the first time;

3) Guidance for the year ending December 31, 2009 has been provided for the first time;

4) Production assumptions have been updated, including assumed assets sales with production losses of 30 mmcf/d in 2007 and 60 mmcf/d in 2008 and 2009;

5) Certain cost assumptions have been updated;

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

7) Budgeted capital expenditure assumptions have been updated.

| | Quarter Ending 9/30/2007 | Quarter Ending 12/31/2007 | Year Ending 12/31/2007 | Year Ending 12/31/2008 | Year Ending 12/31/2009 |
|---|---|---|---|---|---|
| Estimated Production | | | | | |
| Oil - mbbls | 2,500 | 2,500 | 9,500 | 10,800 | 11,300 |
| Natural gas - bcf | 165.5 - 167.5 | 171.5 - 173.5 | 632 - 640 | 729.5 - 739.5 | 830 - 840 |
| Natural gas equivalent - bcfe | 180.5 - 182.5 | 186.5 - 188.5 | 688 - 698 | 794.5 - 804.5 | 898 - 908 |
| Daily natural gas equivalent midpoint - in mmcfe | 1,975 | 2,040 | 1,900 | 2,185 | 2,475 |
| NYMEX Prices (a) (for calculation of realized hedging effects only): | | | | | |
| Oil - $/bbl | $69.72 | $67.50 | $65.10 | $67.50 | $67.50 |
| Natural gas - $/mcf | $6.17 | $7.50 | $7.00 | $7.50 | $7.50 |
| Estimated Realized Hedging Effects (based on assumed NYMEX prices above): | | | | | |
| Oil - $/bbl | $2.07 | $3.50 | $4.64 | $4.66 | $4.04 |
| Natural gas - $/mcf | $1.81 | $1.85 | $1.92 | $1.53 | $0.56 |
| Estimated Differentials to | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| NYMEX Prices: | | | | | |
| Oil - $/bbl | 7 - 9% | 7 - 9% | 7 - 9% | 7 - 9% | 7 - 9% |
| Natural gas - $/mcf | 10 - 14% | 10 - 14% | 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 | $0.90 - 1.00 | $0.90 - 1.00 |
| Production taxes (generally 5.5% of O&G revenues) (b) | $0.35 - 0.40 | $0.35 - 0.40 | $0.35 - 0.40 | $0.35 - 0.40 | $0.35 - 0.40 |
| General and administrative | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 | $0.25 - 0.30 |
| Stock-based compensation (non-cash) | $0.09 - 0.11 | $0.08 - 0.10 | $0.08 - 0.10 | $0.10 - 0.12 | $0.10 - 0.12 |
| DD&A of oil and natural gas assets | $2.55 - 2.65 | $2.60 - 2.70 | $2.50 - 2.70 | $2.50 - 2.70 | $2.50 - 2.70 |
| Depreciation of other assets | $0.24 - 0.28 | $0.20 - 0.25 | $0.24 - 0.28 | $0.24 - 0.28 | $0.24 - 0.28 |
| Interest expense(c) | $0.55 - 0.60 | $0.55 - 0.60 | $0.55 - 0.60 | $0.55 - 0.60 | $0.55 - 0.60 |
| Other Income per Mcfe: | | | | | |
| Oil and natural gas marketing income | $0.08 - 0.10 | $0.08 - 0.10 | $0.08 - 0.10 | $0.02 - 0.04 | $0.02 - 0.04 |
| Service operations income | $0.06 - 0.08 | $0.04 - 0.06 | $0.05 - 0.07 | $0.05 - 0.07 | $0.05 - 0.07 |
| Book Tax Rate (About Equals 97% deferred) | 38% | 38% | 38% | 38% | 38% |
| ----------------- | | | | | |
| Equivalent Shares Outstanding - in millions: | | | | | |
| Basic | 454 | 454 | 453 | 458 | 463 |
| Diluted | 520 | 520 | 519 | 524 | 529 |
| Budgeted Capital Expenditures - in millions: | | | | | |
| Drilling | $1,050 - 1,150 | $1,000 - 1,100 | $4,250 - 4,450 | $4,000 - 4,200 | $4,000 - 4,200 |
| Leasehold acquisition costs | $100 - 200 | $100 - 200 | $600 - 800 | $500 - 600 | $500 - 600 |
| Geological and geophysical costs | $50 - 75 | $50 - 75 | $250 - 300 | $200 | $200 |
| | --------- | ---------- | ---------- | ---------- | ---------- |
| Total budgeted capital expenditures | $1,200 - 1,425 | $1,150 - 1,375 | $5,100 - 5,550 | $4,700 - $5,000 | $4,700 - $5,000 |

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

(b) Severance tax per mcfe is based on NYMEX prices of: $69.72 per bbl of oil and $6.80 to $7.95 per mcf of natural gas during Q3 2007; $67.50 per bbl of oil and $6.85 to $7.95 per mcf of natural gas during Q4 2007; $65.10 per bbl of oil and $6.85 to $8.00 per mcf of natural gas during calendar 2007; and $67.50 per bbl of oil and $6.85 to $8.00 per mcf of natural gas during calendar 2008 and 2009.

(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, Chesapeake receives a fixed price and pays 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) 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 pre-determined 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 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 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 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 | Avg. NYMEX Strike Price | Open Swap Positions as a Assuming Natural Gas Production | Total % of Estimated Total Natural | Total Lifted Gain Gains from Lifted Swaps | per Mcf of Estimated Total Natural |
|---|---|---|---|---|---|

| | in Bcf's | of Open Swaps | in Bcf's of: | Gas Production | ($ millions) | Gas Production |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q3 | 72.6 | $7.87 | 166.5 | 44% | $113.8 | $0.68 |
| Q4 | 110.9 | $8.82 | 172.5 | 64% | $116.8 | $0.68 |
| Q3-Q4 2007(1) | 183.5 | $8.44 | 339.0 | 54% | $230.6 | $0.68 |
| Total 2008(1) | 475.3 | $9.27 | 734.5 | 65% | $105.0 | $0.14 |
| Total 2009(1) | 208.0 | $9.12 | 835.0 | 25% | $3.9 | $0.01 |

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $5.75 to $6.50 covering 88 bcf in Q3-Q4 2007, $5.25 to $6.50 covering 225 bcf in 2008 and $5.90 to $6.50 covering 152 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 |
|---|---|---|---|---|---|
| 2007: | | | | | |
| Q3 | 22.1 | $6.76 | $8.20 | 166.5 | 13% |
| Q4 | 19.6 | $7.13 | $8.88 | 172.5 | 11% |
| Q3-Q4 2007(1) | 41.7 | $6.94 | $8.52 | 339.0 | 12% |
| Total 2008(1) | 26.8 | $7.41 | $9.40 | 734.5 | 4% |
| Total 2009(1) | 18.3 | $7.50 | $10.72 | 835.0 | 2% |

(1) Certain collar arrangements include three-way collars that include written put options with strike prices ranging from $5.00 to $6.00 covering 33 bcf in Q3-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 46 bcf of production in Q3-Q4 2007 at a weighted average price of $10.49 for a weighted average premium of $0.61, 110 bcf of production in 2008 at a weighed average price of $10.41 for a weighted average premium of $0.67 and 119 bcf of production in 2009 at a weighed average price of $11.12 for a weighted average premium of $0.61.

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): |
| Q3-Q4 2007 | 74.6 | 0.34 | 18.4 | 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 | 290.5 | $0.30 | 157.2 | $0.33 |

(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 ($255 million as of June 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 |
|---|---|---|---|---|---|---|
| 2007: | | | | | | |
| Q3 | 10.6 | $4.82 | $8.45 | ($3.63) | 166.5 | 6% |
| Q4 | 10.6 | $4.82 | $8.87 | ($4.05) | 172.5 | 6% |
| Q3-Q4 2007 | 21.2 | $4.82 | $8.66 | ($3.84) | 339.0 | 6% |
| Total 2008 | 38.4 | $4.68 | $8.02 | ($3.34) | 734.5 | 5% |
| Total 2009 | 18.3 | $5.18 | $7.28 | ($2.10) | 835.0 | 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:

| Avg. | Assuming Oil | Open Swap Positions as a % of Estimated | Total Gains from Lifted | Total Lifted Gain per bbl of |
|---|---|---|---|---|

| | Open Swaps in mbbls | NYMEX Strike Price | Production in mbbls of: | Oil Production | Total ($ millions) | Swaps Total Oil Production | Estimated |
|---|---|---|---|---|---|---|---|
| 2007: | | | | | | | |
| Q3 | 1,656 | $71.61 | 2,500 | 66% | $2.1 | $0.84 | |
| Q4 | 1,656 | $71.57 | 2,500 | 66% | $2.1 | $0.84 | |
| Q3-Q4 2007(1) | 3,312 | $71.59 | 5,000 | 66% | $4.2 | $0.84 | |
| Total 2008(1) | 7,502 | $72.77 | 10,800 | 69% | $4.8 | $0.45 | |
| Total 2009(1) | 3,650 | $76.75 | 11,300 | 32% | -- | -- | |

(1) Certain hedging arrangements include cap-swaps and knockout swaps with provisions limiting the counterparty's exposure below prices ranging from $45.00 to $60.00 covering 1,472 mbbls in Q3-Q4 2007 and 3,478 mbbls in 2008 and from $52.50 to $60.00 covering 3,103 mbbls in 2009.

Note: Not shown above are written call options covering 1,282 mbbls of production in 2008 at a weighted average price of $75.00 for a weighted average premium of $4.72 and 2,190 mbbls of production in 2009 at a weighed average price of $75.00 for a weighted average premium of $5.47.

CONTACT: Chesapeake Energy Corporation
Jeffrey L. Mobley, CFA, 405-767-4763
Senior Vice President - Investor Relations and Research
jmobley@chkenergy.com
or
Marc Rowland, 405-879-9232
Executive Vice President and Chief Financial Officer
mrowland@chkenergy.com
SOURCE: Chesapeake Energy Corporation

---