NEWS RELEASE

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2006 Third Quarter

Net Income Available to Common Shareholders Reaches $523 Million on Revenue of $1.9 Billion and Production of 147 Bcfe; Net Income of $1.13 per Fully Diluted Common Share Increases 163% Over the 2005 Third Quarter Proved Reserves Reach Record Level of 8.4 Tcfe; Company Delivers Year To Date Reserve Replacement Rate of 314% From 1.34 Tcfe of Additions at a Drilling and Acquisition Cost of $1.89 per Mcfe Recent Acquisitions Add 490 Bcfe of Proved and Unproved Reserves in South Texas, Fort Worth Barnett Shale and Northwest Oklahoma Plays; Company Expands West Texas Delaware Shale Position to 700,000 Net Acres and Increases Fayetteville Core Position to 340,000 Net Acres; Company Enters Shale Plays in Alabama, Kentucky and Illinois Company Updates Detailed Review of its 16.4 Tcfe of Risked Unproved Reserves Located on its 10.5 Million Net Acres of U.S. Onshore Leasehold and Significantly Increases its Production Growth Forecasts for 2007 and 2008 Business Editors/Energy Editors

OKLAHOMA CITY--(BUSINESS WIRE)--Oct. 26, 2006--Chesapeake Energy Corporation (NYSE:CHK) today reported strong financial and operating results for the third quarter of 2006. For the quarter, Chesapeake generated net income available to common shareholders of $523 million ($1.13 per fully diluted common share), operating cash flow of $989 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.329 billion (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.929 billion and production of 147 billion cubic feet of natural gas equivalent (bcfe). For the quarter, ebitda and net income per fully diluted common share increased 129% and 163%, respectively, over the 2005 third quarter.

The company's 2006 third quarter net income available to common shareholders and ebitda include an after-tax unrealized mark-to-market gain of $150 million resulting from the company's oil and natural gas and interest rate hedging programs that is typically not included in published estimates of the company's financial results by certain securities analysts. Excluding this item, Chesapeake's net income to common shareholders in the 2006 third quarter would have been $373 million ($0.83 per fully diluted common share) and ebitda would have been $1.091 billion. The foregoing item does not affect the calculation of operating cash flow. For the quarter, adjusted ebitda and adjusted net income per fully diluted common share increased 59% and 28%, respectively, over the 2005 third quarter. 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 21-24 of this release.

Key Operational and Financial Statistics Summarized Below for the 2006 Third Quarter, 2006 Second Quarter and 2005 Third Quarter

The table below summarizes Chesapeake's key results during the 2006 third quarter and compares them to the 2006 second quarter and the 2005 third quarter.

	Three Months Ended:		
	9/30/06	6/30/06	9/30/05
Average daily production (in mmcfe)	1,597	1,568	1,308
Natural gas as % of total production	91	91	90
Natural gas production (in bcf)	133.8	129.8	108.8
Average realized natural gas price ($/mcf) (a)	8.39	8.04	6.64
Oil production (in mbbls)	2,178	2,143	1,926
Average realized oil price ($/bbl) (a)	60.62	58.80	53.30
Natural gas equivalent production (in bcfe)	146.9	142.7	120.4
Natural gas equivalent realized price ($/mcfe) (a)	8.54	8.20	6.85

Oil and natural gas marketing income ($/mcfe)	.09	.08	.07
Service operations income ($/mcfe)	.13	.10	-
Production expenses ($/mcfe)	(.84)	(.85)	(.67)
Production taxes ($/mcfe) (b)	(.28)	(.24)	(.44)
General and administrative costs ($/mcfe) (c)	(.20)	(.19)	(.09)
Stock-based compensation ($/mcfe)	(.06)	(.05)	(.04)
DD&A of oil and natural gas properties ($/mcfe)	(2.34)	(2.30)	(1.92)
D&A of other assets ($/mcfe)	(.18)	(.16)	(.11)
Interest expense ($/mcfe) (a)	(.52)	(.51)	(.48)
Operating cash flow ($ in millions) (d)	988.6	914.2	634.6
Operating cash flow ($/mcfe)	6.73	6.41	5.27
Adjusted ebitda ($ in millions) (e)	1,090.7	1,001.4	686.2
Adjusted ebitda ($/mcfe)	7.43	7.02	5.70
Net income to common shareholders ($ in millions)	522.6	332.1	149.1
Earnings per share - assuming dilution ($)	1.13	0.82	0.43
Adjusted net income to common shareholders ($ in millions) (f)	373.1	339.8	234.1
Adjusted earnings per share - assuming dilution ($)	0.83	0.82	0.65

(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) 2006 second quarter includes an $11.6 million reversal of a severance tax accrual

(c) excludes expenses associated with non-cash stock-based compensation

(d) defined as cash flow provided by operating activities before changes in assets and liabilities

(e) 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 23

(f) defined as net income available to common shareholders, as adjusted to remove the effects of certain items detailed on page 23

Oil and Natural Gas Production Sets Record for 21st Consecutive Quarter; 2006 Third Quarter Average Daily Production Increases 22% Over the 2005 Third Quarter and 2% Over the 2006 Second Quarter

Daily production for the 2006 third quarter averaged 1.597 bcfe, an increase of 289 million cubic feet of natural gas equivalent (mmcfe), or 22%, over the 1.308 bcfe of daily production in the 2005 third quarter and an increase of 29 mmcfe, or 2%, over the 1.568 bcfe produced per day in the 2006 second quarter. Chesapeake's production in the 2006 third quarter did not meet the company's expectations primarily because of delays in Fort Worth Barnett Shale well completions caused by a new drilling program that favors utilizing multi-well drilling pads over single well drilling locations. The company believes this new approach will lead to more efficient field development and may ultimately result in greater per well reserve recoveries. However, it also creates a large backlog of uncompleted wells (currently approximately 30 wells) as all drilling from a pad must be completed before completion and production operations may commence.

The company's current rate of production is approximately 1.66 bcfe per day, which includes approximately 0.1 bcfe per day of previously curtailed production that is now back on line. Based on the company's projected drilling levels and anticipated results, Chesapeake is forecasting production growth of 23-24% for 2006 and is raising its production growth forecasts in 2007 and 2008 to ranges of 14-18% and 10-14%, from previous forecasts of 10-12% and 5-7%, respectively.

Chesapeake's 2006 third quarter production of 146.9 bcfe was comprised of 133.8 billion cubic feet of natural gas (bcf) (91% on a natural gas equivalent basis) and 2.18 million barrels of oil and natural gas liquids (mmbbls) (9% on a natural gas equivalent basis). Chesapeake's average daily production for the quarter of 1.597 bcfe consisted of 1.455 bcf of natural gas and 23,674 barrels (bbls) of oil. The 2006 third quarter was Chesapeake's 21st consecutive quarter of sequential U.S. production growth. Over these 21 quarters, Chesapeake's U.S. production has increased 308%, for an average compound quarterly growth rate of 6.9% and an average compound annual growth rate of 30.5%.

Oil and Natural Gas Proved Reserves Reach Record Level of 8.4 Tcfe; During the First Three Quarters of 2006, Drilling and Acquisition Costs Averaged $1.89 per Mcfe as Company Added 1.34 Tcfe for a Reserve Replacement Rate of 314%

Chesapeake began 2006 with estimated proved reserves of 7.521 trillion cubic feet of natural gas equivalent (tcfe) and ended the third quarter with 8.433 tcfe, an increase of 912 bcfe, or 12%. During the first three quarters of 2006, Chesapeake replaced its 426 bcfe of production with an estimated 1.339 tcfe of new proved reserves, for a reserve replacement rate of 314%. Reserve replacement through the drillbit was 825 bcfe, or 194% of production (including 541 bcfe of positive performance revisions and 387 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and September 30, 2006) and 62% of the total increase. Reserve replacement through the acquisition of proved reserves was 514 bcfe, or 120% of production and 38% of the total increase.

On a per thousand cubic feet of natural gas equivalent (mcfe) basis, the company's total drilling and acquisition costs were $1.89 (excluding costs of $2.6 billion for leasehold and unproved properties acquired during the period and $181 million relating primarily to tax basis step-up and asset retirement obligations, as well as downward revisions of proved reserves from lower natural gas prices). Excluding these items described above, Chesapeake's exploration and development costs through the drillbit were $1.76 per mcfe during the first three quarters of 2006 while reserve replacement costs through acquisitions of proved reserves were $1.99 per mcfe. A complete reconciliation of finding and acquisition costs and a roll-forward of proved reserves are presented on page 19 of this release.

During the first three quarters of 2006, Chesapeake continued the industry's most active drilling program and drilled 1,024 gross (845 net) operated wells and participated in another 1,154 gross (141 net) wells operated by other companies. The company's drilling success rate was 98% for company-operated and non-operated wells. Also during the first three quarters of 2006, Chesapeake invested $1.769 billion in operated wells (using an average of 89 operated rigs), $363 million in non-operated wells (using an average of 74 non-operated rigs), $456 million to acquire new leasehold (exclusive of $2.1 billion in unproved leasehold acquired through acquisitions) and $102 million to acquire 3-D seismic data.

As of September 30, 2006, the estimated future net cash flows of Chesapeake's proved reserves, before income taxes and discounted at 10% (PV-10), were $9.7 billion using field differential adjusted prices of $58.12 per barrel of oil (bbl) (based on a NYMEX quarter-end price of $62.82 per bbl) and $3.96 per thousand cubic feet of natural gas (mcf) (based on a NYMEX quarter-end price of $4.18 per mcf). By comparison, as of June 30, 2006 the PV-10 of Chesapeake's proved reserves was $15.0 billion using field differential adjusted prices of $69.10 per bbl (based on a NYMEX quarter-end price of $73.86 per bbl) and $5.72 per mcf (based on a NYMEX quarter-end price of $6.09 per mcf). In addition to the PV-10 value of its proved reserves, the net book value of the company's other assets (including drilling rigs, land and buildings, investments in securities, long-term derivative instruments and other non-current assets) was $2.8 billion as of September 30, 2006 and $1.8 billion as of June 30, 2006.

Chesapeake's September 30, 2006 PV-10 changes by approximately $329 million for every $0.10 per mcf change in natural gas prices and approximately $50 million for every $1.00 per bbl change in oil prices. The company calculates the standardized measure of future net cash flows in accordance with SFAS 69 only at year-end because applicable income tax information on properties, including recently acquired oil and natural gas interests, is not readily available at other times during the year. As a result, the company is not able to reconcile the interim period-end values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects.

Average Prices Realized, Hedging Results and Hedging Positions Detailed

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 $60.62 per bbl and $8.39 per mcf, for a realized natural gas equivalent price of $8.54 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the third quarter were a negative $5.43 per bbl and a negative $0.52 per mcf. Realized gains and losses from oil and natural gas hedging activities during the quarter generated a $4.43 loss per bbl and a $2.33 gain per mcf, for a 2006 third quarter realized hedging gain of $301 million, or $2.05 per mcfe.

Through the third quarter of 2006, the company realized hedging gains of approximately $807 million from its 2006 hedges, or $1.89 per mcfe. Recently, Chesapeake lifted a portion of its fourth quarter 2006 and full-year 2007, 2008 and 2009 hedges and, as a result, has secured gains of $540 million (including $407 million that has been received in cash from the company's hedging counterparties).

Together with the current $672 million mark-to-market value of our open hedges, $2.019 billion of value has been created for shareholders from Chesapeake's recent hedging activities. This further demonstrates Chesapeake's ability to secure premium price realizations and achieve substantial risk mitigation through its hedging programs.

The following tables compare Chesapeake's hedged production volumes (including only swaps and also including the hedges assumed in the CNR acquisition in November 2005) as of October 26, 2006 to those previously announced as of July 27, 2006. Additionally, we are presenting our gains from lifted natural gas hedges as of October 26, 2006. 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 October 26, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2006 4Q	57%	9.10	88%	65.64
2007 1Q	74%	10.68	82%	70.21
2007 2Q	55%	8.89	69%	72.16
2007 3Q	53%	8.97	69%	71.92
2007 4Q	50%	9.60	69%	71.62
2007 Total	57%	9.61	72%	71.42
2008 Total	51%	9.37	59%	71.45

Open Swap Positions as of July 27, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2006 4Q	87%	9.54	86%	65.64
2007 1Q	84%	11.12	83%	70.21
2007 2Q	70%	9.18	70%	72.16
2007 3Q	69%	9.25	69%	71.92
2007 4Q	68%	9.90	69%	71.62
2007 Total	72%	9.91	73%	71.42
2008 Total	57%	9.37	63%	71.45

Gains From Lifted Natural Gas Hedges as of October 26, 2006

Quarter or Year	Total Gain ($ millions)	Assuming Natural Gas Production of: (bcf)	Gain ($ per mcf)
2006 4Q	215	140	1.54
2007 1Q	109	143	0.76
2007 2Q	55	151	0.37
2007 3Q	56	159	0.35
2007 4Q	70	166	0.42
2007 Total	290	619	0.47
2008 Total	31	701	0.04

2009 Total	4	750	0.01

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The company's updated forecasts for 2006 and 2007 and its initial 2008 forecast are attached to this release in an Outlook dated October 26, 2006 labeled as Schedule "A", which begins on page 25. This Outlook has been changed from the Outlook dated July 27, 2006 (attached as Schedule "B", which begins on page 29) to reflect various updated information.

Company Announces Approximately $660 Million of Acquisitions in South Texas, Fort Worth Barnett Shale and Northwest Oklahoma Plays; Acquires Approximately 490 Bcfe of Proved and Unproved Reserves

Chesapeake has acquired or has agreed to acquire from four private companies natural gas assets located in its South Texas, Fort Worth Barnett Shale and Northwest Oklahoma plays for an aggregate purchase price of approximately $660 million in cash. Through these transactions, Chesapeake is acquiring an internally estimated 490 bcfe of reserves, which are comprised of 160 bcfe of proved reserves and 330 bcfe of unproved reserves.

After allocating $324 million of the $660 million purchase price to unproved reserves and $45 million to midstream assets, Chesapeake's acquisition cost for the 160 bcfe of internally estimated proved reserves will be approximately $1.82 per mcfe. Based on the company's projected development plan, which includes $750 million of anticipated future drilling and development costs, Chesapeake estimates that its all-in cost of acquiring and developing the 490 bcfe of proved and unproved reserves will be approximately $2.80 per mcfe. As a percentage of the combined purchase price, the acquisitions are located 47% in South Texas, 45% in the Fort Worth Barnett Shale and 8% in Northwest Oklahoma.

Chesapeake Increases Cost Inflation Hedges through Additional Oilfield Service Investments

To further hedge its exposure to oilfield service costs and achieve greater operational efficiencies, Chesapeake recently invested approximately $250 million to acquire a 19.9% interest in a rapidly growing privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. This service company also has expansion efforts underway in other key regions in which Chesapeake operates.

This investment complements Chesapeake's direct and indirect drilling rig investments that have served as an effective hedge to higher service costs and have also provided competitive advantages in making acquisitions and in developing the company's own leasehold on a more timely and efficient basis. To date, Chesapeake has invested approximately $254 million to build or acquire 42 drilling rigs and is building 22 additional rigs. During the 2006 third quarter, the company entered into a sale/leaseback transaction to monetize its investment in 18 rigs in exchange for cash proceeds of $188 million. These rigs are under lease to Chesapeake through 2014, at which time the company has the option to reacquire them.

In total, the company's drilling rig fleet should reach 82 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a $69 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake's equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating two rigs and has another eight rigs under construction or on order for delivery in 2006 and 2007.

Chesapeake Significantly Expands Acreage Position in the Fort Worth Barnett Shale Play in Johnson, Tarrant and Western Dallas Counties

During the third quarter, Chesapeake significantly expanded its holdings in the Fort Worth Barnett Shale play through acquisitions totaling approximately 55,400 net acres primarily in Johnson, Tarrant and western Dallas counties. These transactions included 26,500 net acres acquired from Four Sevens Oil Co. Ltd. and Sinclair Oil Corporation, 16,600 net acres acquired from the Dallas/Fort Worth International Airport Board and the cities of Dallas and Fort Worth and 12,300 net acres acquired in two transactions with Dale Resources, LLC, et al. In addition, Chesapeake has continued its ongoing "off-the-ground" leasing efforts in the play through numerous transactions with various municipalities, school districts and industrial and commercial property owners.

Chesapeake's Tier 1 leasehold position now totals approximately 150,000 net acres and is concentrated in the "sweet spot" of Johnson, Tarrant and western Dallas counties. On this acreage, the company believes it has the ability to drill approximately 2,100 additional net horizontal wells with lateral lengths of approximately 3,000 feet on 500 foot average well spacing. The company's expected results for wells drilled on its Tier 1 acreage are $2.7 million to develop 2.45 gross bcfe (1.8 net bcfe after royalties and other burdens). From its Fort Worth Barnett Shale acreage position, Chesapeake is now producing approximately 240 gross mmcfe per day (168 net mmcfe) from 347 gross operated wells, of which Chesapeake has drilled 213 and has acquired 134.

Chesapeake is currently utilizing 17 operated drilling rigs to develop its Fort Worth Barnett Shale acreage and by the end of 2006 should have approximately 24 operated rigs drilling in the play. For 2007 and 2008, Chesapeake is budgeting an average operated drilling rig count of 30-35 rigs in the play. From a program of this scale, the company believes that it should be able to drill 450-500 wells per year and should be able to replace 125-150% of the company's total production from its Fort Worth Barnett Shale drilling program alone. This would leave approximately 100 additional operated rigs to deliver further growth in production and proved reserves elsewhere.

Looking forward, Chesapeake expects to continue acquiring more acreage in the Forth Worth Barnett Shale, primarily in Johnson, Tarrant and western Dallas counties, with a special focus on the urban areas of Tarrant and western Dallas counties. In these areas, Chesapeake has acquired more than 100 urban drillsite pads from which it can drill multiple wells, in some cases up to 12 wells per pad. The ownership of these urban pads and its ongoing land services agreement with Dale Resources provide the company with distinctive advantages in acquiring additional leases in "halo" areas surrounding these pads.

Chesapeake Expands Acreage Positions in the Fayetteville Shale to 1,040,000 Net Acres, West Texas Delaware Shale to 700,000 Net Acres and Southeast Oklahoma Woodford Shale to 100,000 Net Acres; Company Enters Alabama Shale Plays with 110,000 Net Acres and New Albany Thermogenic Shale Play in Illinois and Kentucky with 220,000 Net Acres

Chesapeake has previously stated its goal of establishing a top three presence in every major shale play east of the Rockies. The company believes it has largely accomplished this goal through a focused series of innovative transactions. For example, in the Fayetteville Shale play in Arkansas, Chesapeake now owns approximately 1,040,000 net acres, of which approximately 340,000 net acres are in the highly prospective core area in the central and western portions of the play. The company has drilled 12 horizontal wells to date, is in the process of acquiring several large 3-D seismic surveys and is increasing its operated rig count from two to seven rigs in the play by year-end 2006.

In the Barnett and Woodford Shale plays of the Delaware Basin in far West Texas, the company has entered into four joint venture agreements with one large public independent and three private companies to pursue the development of these shales and other conventional and unconventional plays. In Culberson, Reeves, Pecos and Brewster counties, Chesapeake now owns the right to develop approximately 700,000 net acres (1.3 million gross acres), the largest such leasehold position in the Delaware Shale play. The company currently has two operated rigs drilling on this acreage and plans to further explore the area in 2007 and 2008 with aggressive 3-D seismic and exploratory drilling programs.

Located in the Arkoma Basin of southeastern Oklahoma, the Woodford Shale is a play of increasing importance to Chesapeake. The company recently completed two transactions that increased its leasehold inventory in the play to approximately 100,000 net acres. In 2007, the company plans to shoot two 3-D seismic surveys and currently has one operated rig drilling in the play. To date, Chesapeake has drilled one successful vertical well and one successful horizontal well in the Woodford Shale play.

Earlier this month, Chesapeake announced that it has entered into a 50/50 statewide area of mutual interest covering all of Alabama with Energen Resources Corporation of Birmingham, Alabama. Chesapeake acquired 100,000 net acres from Energen to augment the approximate 10,000 net acres Chesapeake had previously acquired in Alabama. The two companies plan to initiate 3-D seismic and exploratory drilling programs in 2007.

Chesapeake's Leasehold and 3-D Seismic Inventories Now Total 10.5 Million Net Acres and 14.7 Million Acres; Risked Unproved Reserves in the Company's Inventory Now Reach 16.4 Tcfe, Bringing Total Reserve Base to 24.8 Tcfe

Since 2000, Chesapeake has invested $5.7 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (10.5 million net acres) and 3-D seismic (14.7 million acres) in the U.S. On this leasehold, the company has an estimated 25,000 net drilling locations, representing an approximate 10-year inventory of drilling projects, on which it believes it can develop approximately 3.2 tcfe of proved undeveloped reserves and approximately 16.4 tcfe of risked unproved reserves (68 tcfe of unrisked unproved reserves). Chesapeake's 8.4 tcfe of proved reserves and its risked unproved reserves together total approximately 24.8 tcfe.

To develop these assets more aggressively, Chesapeake has continued to significantly strengthen its technical capabilities by increasing its land, geoscience and engineering staff to approximately 800 employees. Today, the company has approximately 4,600 employees, of which approximately 65% work in the company's E&P operations and approximately 35% 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 position and activity in each gas resource play type and highlights notable projects in each play.

Conventional Gas Resource Plays - In its traditional conventional areas (i.e., portions of the Mid-Continent, Permian, Gulf Coast and South Texas regions), where exploration targets are typically deep and defined using 3-D seismic data, Chesapeake believes it has a meaningful competitive advantage due to its operating scale, deep drilling expertise and over 11.9 million acres of 3-D seismic data. In these plays, Chesapeake owns 3.1 million net acres on which it has an estimated 1.0 tcfe of proved undeveloped reserves and an estimated 2.9 tcfe of risked unproved reserves and is currently utilizing 39 operated drilling rigs (up to 40 rigs by year-end) to further develop its inventory of approximately 3,200 drillsites. Three of Chesapeake's most important conventional gas resource plays are described below.

-- South Texas: Located primarily in Zapata County, Texas, Chesapeake's South Texas assets are currently producing approximately 150 mmcfe per day and the company is currently utilizing eight rigs (also eight rigs at year-end) to develop its 140,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in South Texas are an estimated 169 bcfe and its risked unproved reserves are an estimated 300 bcfe after applying a 75% risk factor and assuming an additional 350 net wells are drilled in the years ahead. The company's expected results for vertical South Texas wells are $2.8 million to develop 1.8 bcfe on 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 currently producing approximately 105 mmcfe per day from the Mountain Front area and is currently utilizing three rigs (up to four rigs by year-end) to develop its 130,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Mountain Front are an estimated 60 bcfe and its risked unproved reserves are an estimated 200 bcfe after applying a 70% risk factor and assuming an additional 80 net wells are drilled in the years ahead. The company's expected results for vertical Mountain Front wells are $8.0 million to develop 4.0 bcfe on 320 acre spacing.

-- 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 currently producing approximately 154 mmcfe per day and is currently utilizing eight rigs (up to nine rigs by year-end) to develop its 375,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in southern Oklahoma are an estimated 239 bcfe and its risked unproved reserves are an estimated 800 bcfe after applying a 75% risk factor and assuming an additional 600 net wells are drilled in the years ahead. The company's expected results for southern Oklahoma wells are $3.5 million to develop 2.2 bcfe on 120 acre spacing.

Unconventional Gas Resource Plays - In its unconventional gas resource areas, Chesapeake owns 1.3

million net acres on which it has an estimated 1.6 tcfe of proved undeveloped reserves and an estimated 6.5 tcfe of risked unproved reserves and is currently utilizing 53 operated drilling rigs (up to 62 rigs by year-end) to further develop its inventory of approximately 9,800 net drillsites. Four 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 unconventional gas resource play in the U.S. In this play, Chesapeake believes it is the third largest producer of natural gas, the third most active driller and the largest leasehold owner in the Tier 1 sweet spot of Tarrant, Johnson and western Dallas counties. Chesapeake is currently producing approximately 168 mmcfe per day from the Fort Worth Barnett Shale and is currently utilizing 17 rigs (up to 24 rigs by year-end) to develop its 165,000 net acres of leasehold, of which 150,000 net acres are located in the Tier 1 area. Chesapeake's proved undeveloped reserves in the Fort Worth Barnett are an estimated 470 bcfe and its risked unproved reserves are an estimated 3.3 tcfe after applying a 15% risk factor and assuming an additional 2,100 net wells are drilled in the years ahead. The company's expected results for horizontal Fort Worth Barnett Shale wells are $2.7 million to develop 2.45 bcfe on approximately 60 acre spacing.

-- Sahara (primarily Mississippi, Chester, Hunton formations in Northwest Oklahoma): In this vast play that extends across five counties in northwestern Oklahoma, Chesapeake is the largest producer of natural gas, the most active driller and the largest leasehold owner in the area. Chesapeake is currently producing approximately 145 mmcfe per day in the Sahara area and is currently utilizing 15 rigs (also 15 rigs at year-end) to develop its 570,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Sahara are an estimated 401 bcfe and its risked unproved reserves are an estimated 2.3 tcfe after applying a 25% risk factor and assuming an additional 5,600 net wells are drilled in the years ahead. The company's expected results for vertical Sahara wells are $0.9 million to develop 0.6 bcfe on approximately 65 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 believes it is one of the ten largest producers of natural gas, the third most active driller and one of the largest leasehold owners in the area. Chesapeake is currently producing approximately 103 mmcfe per day in the Ark-La-Tex region and is currently utilizing 13 rigs (also 13 rigs at year-end) to further develop its 270,000 net acres of leasehold. Chesapeake's unconventional proved undeveloped reserves in the Ark-La-Tex region are an estimated 349 bcfe and its unconventional risked unproved reserves are an estimated 500 bcfe after applying a 70% risk factor and assuming an additional 1,100 net wells are drilled in the years ahead. The company's expected results for medium-depth vertical Ark-La-Tex wells are $1.6 million to develop 1.0 bcfe on approximately 60 acre spacing.

-- Granite, Atoka and Cherokee Washes (western Oklahoma and Texas Panhandle): Chesapeake believes it is the largest producer of natural gas, the most active driller and the largest leasehold owner in the Wash plays in the Anadarko Basin. Chesapeake is currently producing approximately 115 mmcfe per day from these plays and is currently utilizing eight rigs (up to nine rigs by year-end) to further develop its 135,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Wash plays are an estimated 338 bcfe and its risked unproved reserves are an estimated 400 bcfe after applying a 50% risk factor and assuming an additional 650 net wells are drilled in the years ahead. The company's expected results for vertical Wash wells are $2.8 million to develop 1.4 bcfe on 80 acre spacing.

Emerging Unconventional Gas Resource Plays - In its emerging unconventional gas resource areas where commercial production has only recently been established but the future reserve potential could be substantial, Chesapeake owns 2.6 million net acres on which it has an estimated 140 bcfe of proved undeveloped reserves and an estimated 5.1 tcfe of risked unproved reserves and is currently utilizing 14 operated drilling rigs (up to 21 rigs by year-end) to further develop its inventory of approximately 3,100 net drillsites. Five of Chesapeake's most important emerging unconventional gas resource plays are described below.

-- Fayetteville Shale (Arkansas): In this region of rapidly growing importance to Chesapeake, the company is the largest leasehold owner in the play (second largest in the core area of the play). Chesapeake is currently producing approximately 11 mmcfe per day from the Fayetteville Shale and is currently utilizing two rigs (up to seven rigs by year-end) to further develop its 340,000 net acres of leasehold in the core area of the play. Chesapeake's proved undeveloped reserves in the Fayetteville core area are an estimated 35 bcfe and its risked unproved reserves are an estimated 2.5 tcfe after applying a 50% risk factor and assuming an additional 2,100 net wells are drilled in the years ahead. The company's expected results for horizontal Fayetteville Shale wells are $2.5 million to develop 1.4 bcfe on 80 acre spacing. The company is currently risking its 700,000 net acres of non-core leasehold at 100%.

-- Deep Haley (primarily Strawn, Atoka, Morrow formations in West Texas): In this West Texas Delaware Basin area of increasing value to Chesapeake, the company is the second largest leasehold owner and the second most active driller. Chesapeake is currently producing approximately 26 mmcfe per day from the Deep Haley area and is currently utilizing eight rigs (also eight rigs at year-end) to further develop its 235,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in Deep Haley are an estimated 74 bcfe and its risked unproved reserves are an estimated 900 bcfe after applying a 75% risk factor and assuming an additional 180 net wells are drilled in the years ahead. The company's expected results for vertical Deep Haley wells are $10.5 million to develop 7.0 bcfe on 320 acre spacing.

-- Delaware Basin Shales (primarily Barnett and Woodford formations in West Texas): Chesapeake's most significant land acquisition activities during 2006 have taken place in the Delaware Basin Barnett and Woodford Shale play in far West Texas. In this promising play, Chesapeake is now the largest leasehold owner. The company is currently producing approximately 1.0 mmcfe per day from the Delaware Basin Barnett and Woodford Shales and is currently utilizing two rigs (also two rigs at year-end) to further develop its 700,000 net acres of leasehold. Chesapeake has not yet booked any proved reserves in the Delaware Basin shales plays although its risked unproved reserves are an estimated 1.0 tcfe after applying a 90% risk factor and assuming an additional 450 net wells are drilled in the years ahead. The company's expected results for Delaware Basin vertical Barnett and Woodford Shale wells are $4.5 million to develop 3.0 bcfe on 160 acre spacing.

-- Woodford Shale (southeastern Oklahoma Arkoma Basin):

Chesapeake believes it has become one of the top three leasehold owners in the Woodford Shale play, an improving unconventional gas play in the southeastern Oklahoma portion of the Arkoma Basin. The company is currently producing approximately 10.0 mmcfe per day from the Woodford Shale and is currently utilizing one rig (up to two rigs by year-end) to drill horizontal Woodford Shale wells on its 100,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the play are an estimated 14 bcfe and its risked unproved reserves are an estimated 400 bcfe after applying a 50% risk factor and assuming an additional 250 net wells are drilled in the years ahead. The company's expected results for horizontal Woodford Shale wells are $4.0 million to develop 2.2 bcfe on 160 acre spacing.

-- Deep Bossier (East Texas and northern Louisiana): Chesapeake believes it has become one of the top three leasehold owners in the emerging Deep Bossier play. The company is currently producing approximately 1.0 mmcfe per day in the Deep Bossier play and is currently utilizing one rig (up to two rigs by year-end) to further develop its 180,000 net acres of leasehold. Chesapeake's proved undeveloped reserves in the Deep Bossier play are an estimated 14 bcfe and its risked unproved reserves are an estimated 200 bcfe after applying a 90% risk factor and assuming an additional 60 net wells are drilled in the years ahead. The company's expected results for Deep Bossier wells are $10.0 million to develop 5.0 bcfe on 320 acre spacing.

Appalachian Basin Gas Resource Plays - In this core area of the company's operations, play types include conventional, unconventional and emerging unconventional in the Devonian Shale and other formations. Chesapeake is the largest leasehold owner in the region with 3.5 million net acres. The company is currently producing approximately 130 mmcfe per day and is currently utilizing 14 rigs (10 rigs at year-end) to further develop its extensive leasehold position. In Appalachia, Chesapeake has an estimated 500 bcfe of proved undeveloped reserves and its risked unproved reserves are an estimated 1.9 tcfe after applying a 35% risk factor and assuming an additional 8,700 net wells are drilled in the years ahead. The company's expected results for vertical conventional Devonian Shale wells are $0.425 million to develop 0.3 bcfe on 160 acre spacing.

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

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are pleased to report outstanding financial and operational results for the 2006 third quarter. The company delivered attractive production and reserve growth and generated impressive profit margins that were enhanced by the company's timely and well-executed hedging strategy. Our focused business strategy, value-added growth, tremendous inventory of undrilled locations and valuable hedge positions clearly differentiate Chesapeake in the industry.

"In light of continued strong returns available through the drillbit on our extensive prospect inventory, we continue to increase our industry-leading U.S. drilling activity to accelerate development of our substantial proved undeveloped and unproved reserve base. We currently have 120 operated rigs working, up from an average of 73 operated rigs in 2005 and an average of 89 operated rigs to date in 2006. We anticipate increasing our drilling activity to approximately 133 operated rigs by year-end 2006 and up to 150 operated rigs in 2007.

"We are clearly transitioning from the past six years of resource inventory capture to many more years of resource inventory conversion. We believe the result of this transition will be significant increases in proved reserves and production levels in 2007 and beyond. This shift in focus is best evidenced by the increases in future production growth rate ranges that we are announcing today, 14-18% for 2007 and 10-14% for 2008.

"Our business strategy continues to feature delivering growth through a balance of acquisitions and organic drilling, focusing on clean-burning, domestically-produced natural gas to take advantage of strong long-term natural gas supply and demand fundamentals, building dominant regional scale to achieve low operating costs and high returns on capital and mitigating financial and operational risks through opportunistic hedging. We believe Chesapeake's management team can continue the successful execution of the company's distinctive business strategy and continue to deliver significant value to the company's investors for years to come."

Conference Call Information

A conference call to discuss this release has been scheduled for Friday morning, October 27, 2006 at 9:00 a.m. EDT. The telephone number to access the conference call is 913-981-5543 and the confirmation code is 3952942. We encourage those who would like to participate in the call to dial the access number between 8:50 and 8:55 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from noon EDT, October 27, 2006 through midnight EST on November 10, 2006. The number to access the conference call replay is 719-457-0820 and the passcode for the replay is 3952942. 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 indefinitely.

This press release and the accompanying Outlooks include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include estimates of oil and natural gas reserves, expected oil and natural gas production and future expenses, projections of future oil and natural gas prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in the Prospectus dated June 27, 2006 for our offering of 7.625% Senior Notes due 2013 filed with the Securities and Exchange Commission on June 29, 2006. They include the volatility of oil and natural gas prices; the limitations our level of indebtedness may have on our financial flexibility; our ability to compete effectively against strong independent oil and natural gas companies and majors; the availability of capital on an economic basis to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures; uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities; our ability to effectively consolidate and integrate acquired properties and operations; unsuccessful exploration and development drilling; declines in the values of our oil and natural gas properties resulting in ceiling test write-downs; lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; the negative impact lower oil and natural gas prices could have on our ability to borrow; and drilling and operating risks.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Also, our internal estimates of reserves, particularly those in the properties recently acquired or proposed to be acquired where we may have limited review of data or experience with the reserves, may be subject to revision and may be different from estimates by our external reservoir engineers at year-end. 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 being actually realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

Chesapeake Energy Corporation is the third largest independent 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, Permian Basin, South Texas, Texas Gulf Coast, Barnett Shale, 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, 2006		September 30, 2005	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	1,493,226	10.16	720,928	5.99
Oil and natural gas marketing sales	398,114	2.71	361,915	3.01
Service operations revenue	38,071	0.26	--	--
Total Revenues	1,929,411	13.13	1,082,843	9.00
OPERATING COSTS:				
Production expenses	124,045	0.84	80,765	0.67
Production taxes	40,562	0.28	53,102	0.44
General and administrative expenses	37,382	0.25	15,785	0.13
Oil and natural gas marketing expenses	384,473	2.62	353,510	2.94
Service operations expense	18,821	0.13	--	--
Oil and natural gas depreciation, depletion and amortization	343,723	2.34	231,145	1.92
Depreciation and amortization of other assets	27,016	0.18	12,902	0.11
Total Operating Costs	976,022	6.64	747,209	6.21
INCOME FROM OPERATIONS	953,389	6.49	335,634	2.79
OTHER INCOME (EXPENSE):				
Interest and other income	5,132	0.03	2,428	0.02
Interest expense	(74,112)	(0.50)	(58,593)	(0.48)
Loss on repurchases or exchanges of senior notes	--	--	(747)	(0.01)
Total Other Income (Expense)	(68,980)	(0.47)	(56,912)	(0.47)
Income Before Income Taxes	884,409	6.02	278,722	2.32
Income Tax Expense:				
Current	--	--	--	--
Deferred	336,074	2.29	101,734	0.85
Total Income Tax Expense	336,074	2.29	101,734	0.85

NET INCOME	548,335	3.73	176,988	1.47
Preferred stock dividends	(25,753)	(0.17)	(10,204)	(0.08)
Loss on exchange/conversion of preferred stock	--	--	(17,725)	(0.15)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	522,582	3.56	149,059	1.24

EARNINGS PER COMMON SHARE:		
Basic	$1.25	$0.46
Assuming dilution	$1.13	$0.43
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)		
Basic	417,569	322,101
Assuming dilution	483,273	367,639

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

	September 30,		September 30,	
NINE MONTHS ENDED:	2006		2005	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and natural gas sales	4,190,430	9.83	2,032,271	6.01
Oil and natural gas marketing sales	1,170,091	2.74	882,040	2.61
Service operations revenue	97,473	0.23	--	--
Total Revenues	5,457,994	12.80	2,914,311	8.62
OPERATING COSTS:				
Production expenses	364,134	0.85	222,660	0.66
Production taxes	129,858	0.30	136,313	0.40
General and administrative expenses	99,728	0.23	39,640	0.12
Oil and natural gas marketing expenses	1,131,521	2.66	860,789	2.55
Service operations expense	48,925	0.12	--	--
Oil and natural gas depreciation, depletion and amortization	976,839	2.29	621,484	1.84

Depreciation and amortization of other assets	74,051	0.17	34,791	0.10
Employee retirement expense	54,753	0.13	--	--
Total Operating Costs	2,879,809	6.75	1,915,677	5.67
INCOME FROM OPERATIONS	2,578,185	6.05	998,634	2.95
OTHER INCOME (EXPENSE):				
Interest and other income	19,742	0.04	7,790	0.02
Interest expense	(220,226)	(0.52)	(155,623)	(0.46)
Gain on sale of investment	117,396	0.28	--	--
Loss on repurchases or exchanges of senior notes	--	--	(70,047)	(0.20)
Total Other Income (Expense)	(83,088)	(0.20)	(217,880)	(0.64)
Income Before Income Taxes	2,495,097	5.85	780,754	2.31
Income Tax Expense:				
Current	--	--	--	--
Deferred	963,136	2.26	284,977	0.84
Total Income Tax Expense	963,136	2.26	284,977	0.84
NET INCOME	1,531,961	3.59	495,777	1.47
Preferred stock dividends	(62,793)	(0.15)	(25,526)	(0.08)
Loss on exchange/conversion of preferred stock	(10,556)	(0.02)	(22,468)	(0.07)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	1,458,612	3.42	447.783	1.32
EARNINGS PER COMMON SHARE:				
Basic	$3.75		$1.42	
Assuming dilution	$3.40		$1.32	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's)				
Basic	389,136		314,425	

Assuming dilution	450,680	352,210

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

	September 30, 2006	December 31, 2005
Cash	$716	$60,027
Other current assets	1,911,579	1,123,370
Total Current Assets	1,912,295	1,183,397
Property and equipment (net)	20,000,963	14,411,887
Other assets	1,481,663	523,178
Total Assets	$23,394,921	$16,118,462
Current liabilities	$2,004,272	$1,964,088
Long-term debt	7,861,108	5,489,742
Asset retirement obligation	179,149	156,593
Other long-term liabilities	253,884	528,738
Deferred tax liability	2,903,688	1,804,978
Total Liabilities	13,202,101	9,944,139
Stockholders' Equity	10,192,820	6,174,323
Total Liabilities & Stockholders' Equity	$23,394,921	$16,118,462
Common Shares Outstanding	436,553	370,190

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

	September 30, 2006	December 31, 2005	September 30, 2005
Long-term debt, net	$7,861,108	$5,489,742	$4,250,160
Stockholders' equity	10,192,820	6,174,323	4,206,320
Total	$18,053,928	$11,664,065	$8,456,480

CHESAPEAKE ENERGY CORPORATION
CAPITALIZATION RATIOS
(unaudited)

	September 30, 2006	December 31, 2005	September 30, 2005

Long-term debt, net	44%	47%	50%
Stockholders' equity	56%	53%	50%

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF NINE MONTHS ENDED SEPTEMBER 30, 2006 ADDITIONS TO
OIL AND NATURAL GAS PROPERTIES
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs	$2,131,638	1,212,679 (a)	$1.76
Acquisition of proved properties	1,022,777	513,667	$1.99
Subtotal	3,154,415	1,726,346	$1.83
Divestitures	(73)	(117)	
Geological and geophysical costs	101,759	--	
Adjusted subtotal	3,256,101	1,726,229	$1.89
Revisions - price	--	(387,452)	
Acquisition of unproved properties	2,118,867	--	
Leasehold acquisition costs	456,177	--	
Adjusted subtotal	5,831,145	1,338,777	$4.36
Tax basis step-up	177,679	--	
Asset retirement obligation and other	3,125	--	
Total	$6,011,949	1,338,777	$4.49

(a) Includes positive performance revisions of 541 bcfe and excludes downward revisions of 387 bcfe resulting from natural gas price declines between December 31, 2005 and September 30, 2006.

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
NINE MONTHS ENDED SEPTEMBER 30, 2006
(unaudited)

	Mmcfe
Beginning balance, 01/01/06	7,520,690
Extensions and discoveries	671,691
Acquisitions	513,667
Divestitures	(117)
Revisions - performance	540,988
Revisions - price	(387,452)
Production	(426,318)
Ending balance, 9/30/06	8,433,149
Reserve replacement	1,338,777
Reserve replacement rate	314%

CHESAPEAKE ENERGY CORPORATION
SUPPLEMENTAL DATA - OIL AND NATURAL GAS SALES AND INTEREST EXPENSE
(in 000's)

(unaudited)

	THREE MONTHS ENDED September 30, 2006	2005	NINE MONTHS ENDED September 30, 2006	2005
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$141,687	$113,590	$404,595	$290,332
Oil derivatives - realized gains (losses)	(9,660)	(10,937)	(25,695)	(28,654)
Oil derivatives - unrealized gains (losses)	28,724	(4,009)	24,825	(5,951)
Total Oil Sales	160,751	98,644	403,725	255,727
Natural gas sales	811,591	833,992	2,526,168	2,005,670
Natural gas derivatives - realized gains (losses)	311,090	(111,668)	832,769	(97,955)
Natural gas derivatives - unrealized gains (losses)	209,794	(100,040)	427,768	(131,171)
Total Natural Gas Sales	1,332,475	622,284	3,786,705	1,776,544
Total Oil and Natural Gas Sales	$1,493,226	$720,928	$4,190,430	$2,032,271
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$65.05	$58.98	$62.85	$51.08
Natural gas ($ per mcf)	$6.06	$7.67	$6.52	$6.60
Natural gas equivalent ($ per mcfe)	$6.49	$7.87	$6.87	$6.79
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$60.62	$53.30	$58.86	$46.04
Natural gas ($ per mcf)	$8.39	$6.64	$8.66	$6.27
Natural gas equivalent ($ per mcfe)	$8.54	$6.85	$8.77	$6.42
Interest Expense ($ in thousands)				
Interest	$75,100	$58,206	$221,832	$160,209
Derivatives - realized (gains) losses	1,555	(843)	(852)	(2,639)
Derivatives - unrealized (gains) losses	(2,543)	1,230	(754)	(1,947)

Total Interest Expense	$74,112	$58,593	$220,226	$155,623

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

THREE MONTHS ENDED:	September 30, 2006	September 30, 2005
Cash provided by operating activities	$937,275	$557,428
Cash (used in) investing activities	(2,883,948)	(1,115,166)
Cash provided by financing activities	1,581,119	684,840

NINE MONTHS ENDED:	September 30, 2006	September 30, 2005
Cash provided by operating activities	$2,982,419	$1,577,345
Cash (used in) investing activities	(6,668,005)	(3,655,044)
Cash provided by financing activities	3,626,275	2,197,905

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

THREE MONTHS ENDED:	September 30, 2006	June 30, 2006	September 30, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$937,275	$1,077,686	$557,428
Adjustments:			
Changes in assets and liabilities	51,328	(163,520)	77,150
OPERATING CASH FLOW (1)	$988,603	$914,166	$634,578

(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.

September June September

THREE MONTHS ENDED:	30, 2006	30, 2006	30, 2005
NET INCOME	$548,335	$359,903	$176,988
Income tax expense	336,074	244,779	101,734
Interest expense	74,112	73,456	58,593
Depreciation and amortization of other assets	27,016	23,163	12,902
Oil and natural gas depreciation, depletion and amortization	343,723	328,159	231,145
EBITDA (2)	$1,329,260	$1,029,460	$581,362

(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, 2006	June 30, 2006	September 30, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$937,275	$1,077,686	$557,428
Changes in assets and liabilities	51,328	(163,520)	77,150
Interest expense	74,112	73,456	58,593
Unrealized gains (losses) on oil and natural gas derivatives	238,518	16,460	(104,049)
Other non-cash items	28,027	25,378	(7,760)
EBITDA	$1,329,260	$1,029,460	$581,362

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

NINE MONTHS ENDED:	September 30, 2006	September 30, 2005
CASH PROVIDED BY OPERATING ACTIVITIES	$2,982,419	$1,577,345
Adjustments:		
Changes in assets and liabilities	(32,787)	15,589
OPERATING CASH FLOW (1)	$2,949,632	$1,592,934

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(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.

	September 30,	September 30,
NINE MONTHS ENDED:	2006	2005
NET INCOME	$1,531,961	$495,777
Income tax expense	963,136	284,977
Interest expense	220,226	155,623
Depreciation and amortization of other assets	74,051	34,791
Oil and natural gas depreciation, depletion and amortization	976,839	621,484
EBITDA (2)	$3,766,213	$1,592,652

(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:

	September 30,	September 30,
NINE MONTHS ENDED:	2006	2005
CASH PROVIDED BY OPERATING ACTIVITIES	$2,982,419	$1,577,345
Changes in assets and liabilities	(32,787)	15,589
Interest expense	220,226	155,623
Unrealized gains (losses) on oil and natural gas derivatives	452,593	(137,122)
Other non-cash items	143,762	(18,783)
EBITDA	$3,766,213	$1,592,652

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

September 30, June 30, September 30,

THREE MONTHS ENDED:	2006	2006	2005
Net income available to common shareholders	$522,582	$332,128	$149,059
Adjustments:			
Loss on conversion/exchange of preferred stock	--	9,547	17,725
Unrealized (gains) losses on derivatives, net of tax	(149,457)	(9,720)	66,851
Cumulative impact of new Texas margin tax	--	15,000	--
Reversal of severance tax accrual, net of tax	--	(7,192)	--
Loss on repurchases or exchanges of senior notes, net of tax	--	--	474
Adjusted net income available to common shareholders (1)	373,125	339,763	234,109
Preferred dividends	25,753	18,228	10,204
Total adjusted net income	$398,878	$357,991	$244,313
Weighted average fully diluted shares outstanding (2)	483,273	434,915	376,600
Adjusted earnings per share assuming dilution	$0.83	$0.82	$0.65

(1) Adjusted net income available to common and adjusted earnings per share assuming dilution exclude certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to GAAP earnings because:

a. Management uses adjusted net income available to common to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

b. Adjusted net income available to common is more comparable to earnings estimates provided by securities analysts.

c. Items excluded generally are one-time items, or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

(2) Weighted average fully diluted shares outstanding includes shares that were considered antidilutive for calculating earnings per share in accordance with GAAP.

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

THREE MONTHS ENDED:	September 30, 2006	June 30, 2006	September 30, 2005
EBITDA	$1,329,260	$1,029,460	$581,362
Adjustments, before tax:			
Unrealized (gains) losses on oil and natural gas			

derivatives	(238,518)	(16,460)	104,049
Reversal of severance tax accrual	--	(11,600)	--
Loss on repurchases or exchanges of senior notes	--	--	747
Adjusted EBITDA (1)	$1,090,742	$1,001,400	$686,158

(1) Adjusted EBITDA excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to EBITDA because:

a. Management uses adjusted EBITDA to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

b. Adjusted EBITDA is more comparable to earnings estimates provided by securities analysts.

c. Items excluded generally are one-time items, or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

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

NINE MONTHS ENDED:	September 30, 2006	September 30, 2005
Net income available to common shareholders	$1,458,612	$447,783
Adjustments:		
Loss on conversion/exchange of preferred stock	10,556	22,468
Unrealized (gains) losses on derivatives, net of tax	(281,076)	85,836
Cumulative impact of new Texas margin tax	15,000	--
Reversal of severance tax accrual, net of tax	(7,192)	--
Gain on sale of investment, net of tax	(72,786)	--
Employee retirement expense, net of tax	33,947	--
Loss on repurchases or exchanges of senior notes, net of tax	--	44,480
Adjusted net income available to common shareholders (1)	1,157,061	600,567
Preferred dividends	62,793	25,526
Total adjusted net income	$1,219,854	$626,093
Weighted average fully diluted shares outstanding (2)	450,680	365,135
Adjusted earnings per share assuming dilution	$2.71	$1.71

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

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

NINE MONTHS ENDED:	September 30, 2006	September 30, 2005
EBITDA	$3,766,213	$1,592,652
Adjustments, before tax:		
Unrealized (gains) losses on oil and natural gas derivatives	(452,593)	137,122
Reversal of severance tax accrual	(11,600)	--
Gain on sale of investment	(117,396)	--
Employee retirement expense	54,753	--
Loss on repurchases or exchanges of senior notes	--	70,047
Adjusted EBITDA (1)	$3,239,377	$1,799,821

(1) Adjusted EBITDA excludes certain items that management believes affect the comparability of operating results. The company discloses these non-GAAP financial measures as a useful adjunct to EBITDA because:

a. Management uses adjusted EBITDA to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

b. Adjusted EBITDA is more comparable to earnings estimates provided by securities analysts.

c. Items excluded generally are one-time items, or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF OCTOBER 26, 2006

Quarter Ending December 31, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007; and Year Ending December 31, 2008.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of October 26, 2006, we are using the following key assumptions in our projections for the fourth quarter of 2006, the full-year 2006, the full-year 2007 and the full-year 2008.

The primary changes from our July 27, 2006 Outlook are in italicized bold in the table and are explained as follows:

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

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

3) We have shown our projections for the quarter ending December 31, 2006 and for the year ending December 31, 2008 for the first time.

	Quarter Ending 12/31/2006	Year Ending 12/31/2006
Estimated Production		
Oil - mbbls	2,100	8,500
Natural gas - bcf	139 - 141	527 - 529
Natural gas equivalent - bcfe	151.5 - 153.5	578 - 580
Daily natural gas equivalent midpoint - in mmcfe	1,658	1,586
NYMEX Prices (a) (for calculation of realized hedging effects only):		
Oil - $/bbl	$56.25	$65.23
Natural gas - $/mcf	$6.40	$7.20
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		
Oil - $/bbl	$8.07	-$1.03
Natural gas - $/mcf	$3.07	$2.42
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	6 - 8%	7 - 9%
Natural gas - $/mcf	8 - 12%	10 - 15%
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.85 - 0.95	$0.85 - 0.90
Production taxes (generally 6.0% of O&G revenues) (b)	$0.36 - 0.40	$0.35 - 0.40
General and administrative	$0.17 - 0.22	$0.15 - 0.20
Stock-based compensation (non-cash)	$0.10 - 0.11	$0.06 - 0.08
DD&A of oil and natural gas assets	$2.35 - 2.40	$2.30 - 2.35
Depreciation of other assets	$0.19 - 0.23	$0.18 - 0.22
Interest expense(c)	$0.58 - 0.62	$0.54 - 0.58
Other Income per Mcfe:		
Oil and natural gas marketing income	$0.02 - 0.04	$0.06 - 0.08
Service operations income	$0.08 - 0.10	$0.08 - 0.10
Book Tax Rate (approximately 95% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	420	397
Diluted	486	459
Capital Expenditures - in millions:		
Drilling, leasehold and seismic	$1,100 -1,300	$4,700 - 4,900

	Year Ending 12/31/2007	Year Ending 12/31/2008
Estimated Production		
Oil - mbbls	8,500	8,500
Natural gas - bcf	614 - 624	696 - 706
Natural gas equivalent - bcfe	665 - 675	747 - 757
Daily natural gas equivalent midpoint - in mmcfe	1,836	2,055
NYMEX Prices (a) (for calculation of realized hedging effects only):		
Oil - $/bbl	$56.25	$56.25
Natural gas - $/mcf	$7.50	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):		

Oil - $/bbl	$10.42	$8.65
Natural gas - $/mcf	$1.80	$1.09
Estimated Differentials to NYMEX Prices:		
Oil - $/bbl	6 - 8%	6 - 8%
Natural gas - $/mcf	9 - 13%	9 - 13%
Operating Costs per Mcfe of Projected Production:		
Production expense	$0.90 - 1.00	$0.90 - 1.00
Production taxes (generally 6.0% of O&G revenues) (b)	$0.41 - 0.46	$0.41 - 0.46
General and administrative	$0.20 - 0.25	$0.22 - 0.27
Stock-based compensation (non-cash)	$0.08 - 0.10	$0.08 - 0.10
DD&A of oil and natural gas assets	$2.40 - 2.50	$2.40 - 2.50
Depreciation of other assets	$0.24 - 0.28	$0.28 - 0.32
Interest expense(c)	$0.60 - 0.65	$0.60 - 0.65
Other Income per Mcfe:		
Oil and natural gas marketing income	$0.06 - 0.08	$0.06 - 0.08
Service operations income	$0.10 - 0.12	$0.10 - 0.12
Book Tax Rate (approximately 95% deferred)	38%	38%
Equivalent Shares Outstanding - in millions:		
Basic	440	445
Diluted	505	510
Capital Expenditures - in millions:		
Drilling, leasehold and seismic	$4,700 - 4,900	$4,700 -4,900

(a) Oil NYMEX prices have been updated for actual contract prices through September 2006 and natural gas NYMEX prices have been updated for actual contract prices through October 2006.

(b) Severance tax per mcfe is based on NYMEX prices of $56.25 per bbl of oil and $6.40 to $7.20 per mcf of natural gas during Q4 2006, $65.23 per bbl of oil and $6.20 to $7.20 per mcf of natural gas during calendar 2006, $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2007 and 2008.

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

Commodity Hedging Activities

The company utilizes hedging strategies to hedge the price of a portion of its future oil and natural gas production. These strategies include:

(i) For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

(ii) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.

(iii) Basis protection swaps are arrangements that guarantee a price differential of oil or natural gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or 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 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 2006 (1)	69.7	$8.91	140.0	50%	$215	$1.54
2007:						
Q1	95.0	$10.65	143.2	67%	$109	$0.76
Q2	72.4	$8.95	150.6	48%	$55	$0.37
Q3	73.1	$9.04	159.2	46%	$56	$0.35
Q4	73.1	$9.71	166.0	44%	$70	$0.42
Total 2007(1)	313.6	$9.66	619.0	51%	$290	$0.47
Total 2008(1)	318.4	$9.53	701.0	45%	$31	$0.04
Total 2009			750.0		$4	$0.01

(1) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 8.6 bcf in 2006, $5.30 to $6.50 covering 72.2 bcf in 2007 and $5.75 to $6.50 covering 76.9 bcf in 2008, respectively.

Note: Not shown above are call options covering 1.8 bcf of production in 2006 at a weighted average price of $12.50, 7.3 bcf of production in 2007 at a weighted average price of $12.50 and 7.3 bcf of production in 2008 at a weighed average price of $12.50.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(a):	Volume in Bcf's	NYMEX plus(a):
Q4 2006	36.8	$0.37	-	$-
2007	141.7	0.34	36.5	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	18.2	0.31

Totals	383.7	$0.31	91.3	$0.34

(a) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($415 million as of September 30, 2006). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities", the derivative instruments assumed in connection with the CNR acquisition 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 2006	10.6	$4.86	$10.38	($5.52)	140.0	8%
2007:						
Q1	10.3	$4.82	$10.97	($6.15)	143.2	7%
Q2	10.5	$4.82	$8.48	($3.66)	150.6	7%
Q3	10.6	$4.82	$8.45	($3.63)	159.2	7%
Q4	10.6	$4.82	$8.87	($4.05)	166.0	6%
Total 2007	42.0	$4.82	$9.18	($4.36)	619.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	701.0	5%
Total 2009	18.3	$5.18	$7.28	($2.10)	750.0	2%

Note: Not shown above are collars covering 3.7 bcf of production in 2009 at an average floor and ceiling of $4.50 and $6.00, respectively.

The company also has the following crude oil swaps in place:

Assuming Open Swap

	Open Swaps in mbbls	Avg. NYMEX Strike Price	Oil Production in mbbls of:	Positions as a % of Estimated Total Oil Production
Q4 2006(1)	1,840	$65.64	2,100	88%
2007:				
Q1	1,710	$70.21	2,095	82%
Q2	1,456	$72.16	2,120	69%
Q3	1,472	$71.92	2,140	69%
Q4	1,472	$71.62	2,145	69%
Total 2007(1)	6,110	$71.42	8,500	72%
Total 2008(1)	5,032	$71.45	8,500	59%
Total 2009	183	$66.10	8,500	2%

(1) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $60.00 covering 184 mbbls in 2006, $45.00 to $60.00 covering 1,460 mbbls in 2007 and $45.00 to $60.00 covering 1,098 mbbls in 2008, respectively.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF JULY 27, 2006

(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF OCTOBER 26, 2006

Quarter Ending September 30, 2006; Year Ending December 31, 2006; Year Ending December 31, 2007.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of July 27, 2006, we are using the following key assumptions in our projections for the third quarter of 2006, the full-year 2006 and the full-year 2007.

The primary changes from our June 5, 2006 Outlook are in italicized bold in the table and are explained as follows:

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

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

3) We have shown our projections for the quarter ending September 30, 2006 for the first time.

	Quarter Ending 9/30/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production (a):			
Oil - mbbls	2,000	8,400	8,400
Natural gas - bcf	136 - 140	531 - 541	595 - 605
Natural gas equivalent - bcfe	148 - 152	581 - 591	645 - 655
Daily natural gas equivalent midpoint -in mmcfe	1,630	1,605	1,781
NYMEX Prices (b) (for calculation of realized hedging effects			

only):			
Oil - $/bbl	$56.25	$61.67	$56.25
Natural gas - $/mcf	$6.96	$7.57	$7.50
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/bbl	$7.26	$1.92	$11.43
Natural gas - $/mcf	$1.89	$1.99	$1.89
Estimated Differentials to NYMEX Prices:			
Oil - $/bbl	6 - 8%	7 - 9%	6 - 8%
Natural gas - $/mcf	8 - 12%	10 - 15%	9 - 13%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.85 - 0.95	$0.85 - 0.95	$0.90 - 1.00
Production taxes (generally 6.0% of O&G revenues) (c)	$0.38 - 0.42	$0.41 - 0.46	$0.41 - 0.46
General and administrative	$0.15 - 0.20	$0.15 - 0.20	$0.15 - 0.20
Stock-based compensation (non-cash)	$0.05 - 0.07	$0.06 - 0.08	$0.08 - 0.10
DD&A of oil and natural gas assets	$2.35 - 2.40	$2.30 - 2.40	$2.40 - 2.50
Depreciation of other assets	$0.18 - 0.22	$0.18 - 0.22	$0.24 - 0.28
Interest expense(d)	$0.55 - 0.59	$0.54 - 0.58	$0.60 - 0.65
Other Income per Mcfe:			
Marketing and other income	$0.02 - 0.04	$0.04 - 0.06	$0.04 - 0.06
Service operations income	$0.10 - 0.12	$0.08 - 0.12	$0.10 - 0.15
Book Tax Rate (approximately 95% deferred)	38%	38%	38%
Equivalent Shares Outstanding:			
Basic	418 mm	397 mm	423 mm
Diluted	484 mm	459 mm	488 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$900 -1,100 mm	$3,700 -4,000 mm	$3,800 - 4,100 mm

(a) Production forecast for Q3 2006 and calendar 2006 excludes provisions for possible production curtailments that the industry and Chesapeake may experience as a result of high pipeline pressures and/or early filling of U.S. natural gas storage facilities.

(b) Oil NYMEX prices have been updated for actual contract prices through June 2006 and natural gas NYMEX prices have been updated for actual contract prices through July 2006.

(c) Severance tax per mcfe is based on NYMEX prices of $56.25 per bbl of oil and $6.80 to $7.60 per mcf of natural gas during Q3 2006, $57.35 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2006 and $56.25 per bbl of oil and $7.50 to $8.50 per mcf of natural gas during calendar 2007.

(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, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

(ii) For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure. In other words, there is no limit to Chesapeake's exposure but there is a limit to the downside exposure of the counterparty.

(iii) Basis protection swaps are arrangements that guarantee a price differential of oil or natural gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Commodity markets are volatile, and as a result, Chesapeake's hedging activity is dynamic. As market conditions warrant, the company may elect to settle a hedging transaction prior to its scheduled maturity date and lock in the gain or loss on the transaction.

Chesapeake enters into oil and natural gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and natural gas prices. Accordingly, associated gains or 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 natural gas swaps in place:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Avg. Gain (Loss) from Locked Swaps	NYMEX Price Including Open & Locked Positions	% Hedged: Open Swap Positions Assuming Natural Gas Production in Bcf's of:	% Hedged: as a % of Estimated Total Natural Gas Production
2006:						
Q1	93.8	$10.81	-$0.09	$10.72	124.1	76%
Q2	101.4	$8.82	-$0.05	$8.77	129.8	78%
Q3	117.9	$8.80	-$0.05	$8.75	138.0	85%
Q4	114.9	$9.46	-$0.04	$9.42	144.1	80%

Total 2006(1)	428.0	$9.42	-$0.05	$9.37	536.0	80%

Total 2007	392.1	$9.99	-$0.03	$9.96	600.0	65%

Total 2008	329.4	$9.53	-	$9.53	642.0	51%

Total 2009	3.7	$9.02	-	$9.02	687.0	1%

(1) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 43.0 bcf in 2006, $5.75 to $6.50 covering 53.9 bcf in 2007 and $5.75 to $6.50 covering 69.5 bcf in 2008, respectively.

Note: Not shown above are collars covering 0.2 bcf of production in 2006 at a weighted average floor and ceiling of $6.00 and $9.70 and call options covering 7.3 bcf of production in 2006 at a weighted average price of $12.50, 25.6 bcf of production in 2007 at a weighted average price of $10.53 and 7.3 bcf of production in 2008 at a weighed average price of $12.50.

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

	Mid-Continent		Appalachia	
	Volume in Bcf's	NYMEX less(a):	Volume in Bcf's	NYMEX plus(a):
2006	130.1	$0.32	-	$-
2007	137.2	0.33	36.5	0.35
2008	118.6	0.27	36.6	0.35
2009	86.6	0.29	18.2	0.31
Totals	472.5	$0.30	91.3	$0.34

(a) weighted average

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million ($469 million as of June 30, 2006). The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes listed below at their fair values on the date of our acquisition of CNR.

Pursuant to SFAS 149 "Amendment of SFAS 133 on Derivative Instruments and Hedging Activities", the derivative instruments assumed in connection with the CNR acquisition 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:

% Hedged

	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
2006:						
Q1	7.9	$4.91	$12.14	($7.23)	124.1	6%
Q2	10.5	$4.86	$9.97	($5.11)	129.8	8%
Q3	10.6	$4.86	$9.95	($5.09)	138.0	8%
Q4	10.6	$4.86	$10.38	($5.52)	144.1	7%
Total 2006	39.6	$4.87	$10.51	($5.64)	536.0	7%
Total 2007	42.0	$4.82	$9.18	($4.36)	600.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	642.0	6%
Total 2009	18.3	$5.18	$7.28	($2.10)	687.0	3%

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, respectively.

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:	% Hedged: Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	$60.03	2,116	52%
Q2	1,379.5	$61.85	2,143	64%
Q3	1,747.0	$64.83	2,000	87%
Q4	1,840.0	$65.64	2,141	86%
Total 2006(1)	6,076.0	$63.52	8,400	72%
Total 2007	6,110.0	$71.42	8,400	73%
Total 2008	5,032.0	$71.45	8,000	63%
Total 2009	182.5	$66.10	8,000	2%

(1) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $60.00

covering 654.5 mbbls in 2006, $45.00 to $60.00 covering 1,460.0 mbbls in 2007 and $45.00 to $60.00 covering 1,098.0 mbbls in 2008, respectively.

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