NEWS RELEASE

Chesapeake Energy Corporation Reports Record Results for the Fourth Quarter and Full-Year 2005

Company Reports 2005 Fourth Quarter Net Income Available to Common Shareholders of $432 Million on Revenue of $1.751 Billion and Production of 130 Bcfe
Company Reports Full-Year 2005 Net Income Available to Common Shareholders of $880 Million on Revenue of $4.665 Billion and Production of 469 Bcfe
Proved Reserves Reach 7.5 Tcfe from Proved Reserve Adds of 2.6 Tcfe; Reserve Replacement Equals 659% at the Attractive Drilling and Acquisition Cost of $1.74 Per Mcfe
Oil and Gas Production Increases 27% Quarter-Over-Quarter, 29% Year-over-Year, and 8% Sequential Quarter-Over-Quarter; Organic Growth in 2005 Reaches 12%

PRNewswire-FirstCall
OKLAHOMA CITY

Chesapeake Energy Corporation today reported financial and operating results for the fourth quarter of 2005 and for the full-year 2005. For the quarter, Chesapeake generated net income available to common shareholders of $432 million ($1.11 per fully diluted common share), operating cash flow of $833 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $1.066 billion (defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.751 billion and production of 130 billion cubic feet of natural gas equivalent (bcfe).

For the full-year 2005, Chesapeake generated net income available to common shareholders of $880 million ($2.51 per fully diluted common share), operating cash flow of $2.426 billion and ebitda of $2.658 billion on revenue of $4.665 billion and production of 469 bcfe.

The company's fourth quarter and full-year 2005 net income available to common shareholders and ebitda include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Such items and their after-tax effects on fourth quarter and full-year reported results are described as follows:

* an unrealized mark-to-market gain of $113.0 million for the fourth quarter and a $27.1 million gain for the full year resulting from the company's oil and natural gas and interest rate hedging programs;
* a $0.2 million loss for the fourth quarter and a $44.7 million loss for the full year resulting from the early extinguishment of certain Chesapeake debt securities; and
* a reduction of net income available to common shareholders of $4.4 million for the fourth quarter and $26.9 million for the full

year resulting from various exchanges of preferred stock for common stock.

Adjusted for the above-mentioned gains and losses and giving effect to common shares issued for preferred shares during the period, Chesapeake's net income to common shareholders in the fourth quarter of 2005 would have been $324 million ($0.84 per fully diluted common share) and ebitda would have been $888 million. Similarly adjusted, Chesapeake's net income to common shareholders for the full year 2005 would have been $924 million ($2.57 per fully diluted common share) and ebitda would have been $2.687 billion. The foregoing items do not affect the calculation of operating cash flow. A reconciliation of operating cash flow, ebitda, adjusted ebitda and adjusted net income to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 16-19 of this release.

Oil and Natural Gas Production Again Sets Record; Fourth Quarter 2005 Production Up 27% Over Fourth Quarter 2004; Full-Year 2005 Production 29% Higher than Full-Year 2004 Production; Sequential Organic Growth Rate 4% in Fourth Quarter 2005 and 12% for 2005

Production for the 2005 fourth quarter was 130.4 bcfe, an increase of 27.5 bcfe, or 27%, over the 102.9 bcfe produced in the 2004 fourth quarter and an increase of 10.0 bcfe, or 8%, over the 120.4 bcfe produced in the 2005 third quarter. The 27.5 bcfe increase in 2005's fourth quarter production over 2004's fourth quarter production consisted of 12.0 bcfe (44%) generated from organic drillbit growth and 15.5 bcfe (56%) generated from acquisitions, making the company's 2005 organic growth rate 12%. The 10.0 bcfe increase in sequential quarterly production consisted of 3.9 bcfe (39%) generated from organic drillbit growth and 6.1 bcfe (61%) generated from acquisitions, making the company's quarterly organic growth rate 4%. Production for the full-year 2005 was 468.6 bcfe, an increase of 106.0 bcfe, or 29%, over the 362.6 bcfe produced in 2004 and an increase of 200.2 bcfe, or 75%, over the 268.4 bcfe produced in 2003.

Chesapeake's 2005 organic growth of 12% follows organic growth of 20% in 2004, 18% in 2003, 6% in 2002 and 9% in 2001. During these five years, Chesapeake's organic growth rate has been 78% and its average annual organic growth rate has been 12%. The company's total U.S. production growth was 29% in 2005, 35% in 2004, 48% in 2003, 12% in 2002 and 20% in 2001. Chesapeake is anticipating a total production growth rate of 24% in 2006 and organic growth rates of at least 10% in 2006 and 7% in 2007.

Chesapeake's 2005 fourth quarter production of 130.4 bcfe was comprised of 118.3 billion cubic feet of natural gas (bcf) (91% on a natural gas equivalent basis) and 2.01 million barrels of oil and natural gas liquids (mmbbls) (9% on a natural gas equivalent basis). Chesapeake's average daily production rate for the quarter was 1.418 bcfe, consisting of 1.286 bcf of gas and 21,891 barrels (bbls) of oil. The 2005 fourth quarter was Chesapeake's 18th consecutive quarter of sequential production growth. During these 18 quarters, Chesapeake's U.S. production has increased 262%, for an average compound quarterly growth rate of 7.4% and an average compound annual growth rate of 32.8%.

Production for the full-year 2005 of 468.6 bcfe was comprised of 422.4 bcf (90% on a natural gas equivalent basis) and 7.70 mmbbls (10% on a natural gas equivalent basis). Chesapeake's average daily production rate for the year was 1.284 bcfe, consisting of 1.157 bcf of gas and 21,090 bbls of oil and natural gas liquids. The full-year 2005 was Chesapeake's 16th consecutive year of sequential production growth.

During these 16 years, Chesapeake's production has increased at an average compound annual growth rate of 65%.

Oil and Natural Gas Proved Reserves Reach Record Level of 7.5 Tcfe; Drilling and Acquisition Costs Are $1.74 per Mcfe as Company Adds 2.6 Tcfe for a Reserve Replacement Rate of 659%

Chesapeake began 2005 with estimated proved reserves of 4.902 trillion cubic feet of natural gas equivalent (tcfe) and ended the year with 7.521 tcfe, an increase of 2.619 tcfe, or 53%. Including 237 bcfe of internally estimated proved reserves acquired or to be acquired in previously announced transactions subsequent to December 31, 2005, the company's pro forma proved reserves as of year-end were 7.758 tcfe.

During 2005, Chesapeake replaced its 469 bcfe of production with an estimated 3.088 tcfe of new proved reserves, for a reserve replacement rate of 659% at a drilling and acquisition cost of $1.74 per thousand cubic feet of natural gas equivalent (mcfe). Reserve replacement through the drillbit was 1.047 tcfe, or 223% of production (including 17 bcfe from performance revisions and 24 bcfe from oil and natural gas price revisions), or 34% of the total increase, at a cost of $1.74 per mcfe. Reserve replacement through acquisitions of proved reserves (reduced for 1 bcfe sold during the year) was 2.041 tcfe, or 436% of production and 66% of the total increase, also at a cost of $1.74 per mcfe.

Total costs incurred, including drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non-cash tax basis step-up from corporate acquisitions ($252 million in 2005, or $0.08 per mcfe, frequently booked as goodwill in the industry), asset retirement obligations and all other miscellaneous costs capitalized to oil and natural gas properties, were $2.40 per mcfe. These costs exclude future development costs of proved undeveloped reserves. A complete reconciliation of finding and acquisition cost information and a roll forward of proved reserves is presented on page 14 of this release.

Of the company's estimated proved reserves at year-end 2005, 92% were natural gas. Additionally, 65% were proved developed at year-end 2005 compared to 66% in 2004, 74% in 2003, 74% in 2002 and 71% in 2001. By volume, third-party reservoir engineers evaluated 78% of 2005's estimated proved reserves compared to 75% in 2004, 74% in 2003, 73% in 2002 and 71% in 2001. Given that Chesapeake owns an interest in more than 30,000 wells in the U.S., it would be cost prohibitive for third-party reservoir engineers to evaluate 100% of Chesapeake's properties.

As of December 31, 2005, Chesapeake's estimated future net cash flows discounted at 10% before income taxes (PV-10) and after income taxes (standardized measure) from its proved reserves were $22.9 billion and $16.0 billion, respectively, using field differential adjusted prices of $56.41 per bbl (based on a NYMEX year-end price of $61.11 per bbl) and $8.76 per thousand cubic feet ("mcf") (based on a NYMEX year-end price of $10.08 per mcf). In addition to the PV-10 value of its proved reserves, the book value of the company's other assets (including drilling rigs, land and buildings, investments in securities and other non-current assets) was $1.3 billion. The 2004 PV-10 and standardized measure of the company's proved reserves were $10.5 billion and $7.6 billion, respectively, using field differential adjusted prices of $39.91 per bbl (based on a NYMEX year-end price of $43.39 per bbl) and $5.65 per mcf (based on a NYMEX year-end price of $6.18 per mcf). A reconciliation of PV-10 to the standardized measure, which is calculated in accordance with SFAS 69, is presented on page 18 of this release.

Chesapeake's PV-10 changes by approximately $315 million for every $0.10 per mcf change in gas prices and approximately $50 million for every $1.00 per bbl change in oil prices. The decline rate of the company's proved developed producing reserves is projected to be 24% in the first year (calculated by comparing 2007 estimated production to 2006 estimated production), 16% in year two, 13% in year three, 11% in year four and 10% in year five for an average annual decline rate of 15% over the next five years.

Average Prices Realized and Hedging Results and Hedging Positions Detailed

Average prices realized during the 2005 fourth quarter (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such derivatives) were $52.65 per bbl and $8.08 per mcf, for a realized gas equivalent price of $8.14 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the fourth quarter were a negative $4.59 per bbl and a negative $2.86 per mcf. Realized losses from oil and natural gas hedging activities during the quarter generated a $2.72 loss per bbl and a $2.28 loss per mcf, for a 2005 fourth quarter realized hedging loss of $275.1 million, or $2.11 per mcfe.

Average prices realized during the full-year 2005 (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such derivatives) were $47.77 per bbl and $6.78 per mcf, for a realized gas equivalent price of $6.90 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during 2005 were a negative $4.29 per bbl and a negative $1.26 per mcf. Realized losses from oil and natural gas hedging activities during the year generated a $4.43 loss per bbl and a $0.87 loss per mcf, for a full-year 2005 realized hedging loss of $401.7 million, or $0.86 per mcfe. This compares to oil and gas hedging gains of $29.1 million realized from 2001-04 and a current mark-to-market gain of approximately $440 million for the company's oil and gas hedging positions for 2006-09. Chesapeake's first quarter 2006 realized hedging gain is expected to exceed $215 million based on NYMEX prices as of February 17, 2006.

For investors' convenience, the following tables compare Chesapeake's hedged production volumes (through swaps) as of February 23, 2006 to those as of January 17, 2006.

Swap Positions as of February 23, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2006 1Q	74%	$10.72	58%	$60.03
2006 2Q	73%	$8.82	67%	$61.13
2006 3Q	74%	$8.87	64%	$61.50
2006 4Q	64%	$9.36	62%	$61.33
2006 Total	71%	$9.43	63%	$61.02
2007	36%	$9.85	22%	$62.42
2008	22%	$9.10	14%	$65.48

Swap Positions as of January 17, 2006

	Natural Gas		Oil	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX
2006 1Q	74%	$10.72	58%	$60.03
2006 2Q	57%	$8.71	60%	$60.27

2006 3Q	56%	$8.72	57%	$60.56
2006 4Q	46%	$9.01	55%	$60.30
2006 Total	58%	$9.38	57%	$60.29
2007	23%	$9.72	15%	$59.79
2008	13%	$8.82	7%	$63.94

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.

The company's updated first quarter 2006 and full-year 2006 and 2007 forecasts are attached to this release in an Outlook dated February 23, 2006 labeled as Schedule "A". This Outlook has been changed from the Outlook dated January 17, 2006 (attached as Schedule "B" for investors' convenience) to reflect various updated information.

Key Operational and Financial Statistics Summarized Below for 2005 Fourth Quarter and Full-Year 2005

The table below summarizes Chesapeake's key results during the 2005 fourth quarter and compares them to the 2005 third quarter and the 2004 fourth quarter:

	Three Months Ended:		
	12/31/05	9/30/05	12/31/04
Average daily production (in mmcfe)	1,418	1,308	1,119
Gas as % of total production	91	90	90
Natural gas production (in bcf)	118.3	108.8	92.2
Average realized gas price ($/mcf) (A)	8.08	6.64	5.50
Oil production (in mbbls)	2,014	1,926	1,792
Average realized oil price ($/bbl) (A)	52.65	53.30	28.70
Natural gas equivalent production (in bcfe)	130.4	120.4	102.9
Gas equivalent realized price ($/mcfe) (A)	8.14	6.85	5.42
Net marketing income ($/mcfe)	.10	.07	.07
Production expenses ($/mcfe)	(.72)	(.67)	(.55)
Production taxes ($/mcfe)	(.55)	(.44)	(.34)
General and administrative costs ($/mcfe) (B)	(.15)	(.09)	(.08)
Stock-based compensation ($/mcfe)	(.04)	(.04)	(.02)
DD&A of oil and gas properties ($/mcfe)	(2.09)	(1.92)	(1.67)
D&A of other assets ($/mcfe)	(.12)	(.11)	(.09)
Interest expense ($/mcfe) (A)	(.49)	(.48)	(.43)
Operating cash flow ($ in millions) (C)	832.8	634.6	407.6
Operating cash flow ($/mcfe)	6.39	5.27	3.96
Adjusted ebitda ($ in millions) (D)	887.7	686.2	464.7
Adjusted ebitda ($/mcfe)	6.81	5.70	4.51
Net income to common shareholders ($ in millions)	431.8	149.1	163.2

(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 income before income taxes, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 19.

The table below summarizes Chesapeake's key statistics during 2005 and compares them to the prior two years' results:

	Year Ended: 12/31/05	12/31/04	12/31/03
Average daily production (in mmcfe)	1,284	991	735
Gas as % of total production	90	89	90
Natural gas production (in bcf)	422.4	322.0	240.4
Average realized gas price ($/mcf) (A)	6.78	5.29	4.85
Oil production (in mbbls)	7,698	6,764	4,665
Average realized oil price ($/bbl) (A)	47.77	28.33	25.85
Natural gas equivalent production (in bcfe)	468.6	362.6	268.4
Gas equivalent realized price ($/mcfe) (A)	6.90	5.23	4.79
Net marketing income ($/mcfe)	.07	.05	.04
Production expenses ($/mcfe)	(.68)	(.56)	(.51)
Production taxes ($/mcfe)	(.44)	(.29)	(.29)
General and administrative costs ($/mcfe) (B)	(.10)	(.09)	(.08)
Stock-based compensation ($/mcfe)	(.03)	(.01)	(.00)
DD&A of oil and gas properties ($/mcfe)	(1.91)	(1.61)	(1.38)
D&A of other assets ($/mcfe)	(.11)	(.08)	(.06)
Interest expense ($/mcfe) (A)	(.47)	(.45)	(.55)
Operating cash flow ($ in millions) (C)	2,425.7	1,402.5	897.2
Operating cash flow ($/mcfe)	5.18	3.87	3.34
Adjusted ebitda ($ in millions) (D)	2,687.5	1,571.7	1,058.2
Adjusted ebitda ($/mcfe)	5.74	4.33	3.94
Net income to common shareholders ($ in millions)	879.6	439.0	290.5

(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 income before income taxes and cumulative effect of accounting change, interest expense, and depreciation, depletion and amortization expense, as adjusted to remove the effects of certain items detailed on page 19.

Company's Leasehold and 3-D Seismic Inventories Now at 8.4 Million Net Acres

and 11.6 Million Acres, Respectively; Identified Unproved Reserves in Company's Inventory Now 8.8 Tcfe

Chesapeake's exploratory and development drilling programs and production enhancement operations on its existing and acquired properties continue to produce operational results that exceed the company's forecasts and distinguish the company among its peers. During 2005, Chesapeake drilled 902 gross (686 net) operated wells and participated in another 1,066 gross (130 net) wells operated by other companies. The company's drilling success rate was 98% for company-operated wells and 95% for non-operated wells. During the year, Chesapeake invested $1.511 billion in operated wells (using an average of 73 operated rigs), $309 million in non-operated wells (using an average of 66 non-operated rigs) and $362 million in acquiring new 3-D seismic data and leases (exclusive of leases acquired through acquisitions).

Chesapeake attributes its strong organic growth rates during 2005 and in the past five years to management's early recognition that oil and gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry -- people, land and seismic. During the past five years, Chesapeake has invested more than $3.0 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (8.4 million net acres) and 3-D seismic (11.6 million acres) in the U.S. On this leasehold, the company has identified more than a 10-year drilling inventory of approximately 28,000 drilling locations on which it believes it can develop approximately 2.8 tcfe of proved undeveloped reserves and approximately 8.8 tcfe of unproved reserves.

In addition, Chesapeake has significantly strengthened its technical capabilities during the past five years by increasing its land, geoscience and engineering staff by 400% to over 600 employees. Today, the company has more than 3,300 employees, of which approximately 70% work in the company's E&P operations and 30% 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 gas resource and Appalachian Basin gas resource. The company's leasehold and proved undeveloped and unproved reserve totals by play type are set forth below:

* 2.8 million net acres in its traditional conventional areas (i.e., much of the Mid-Continent, Permian, Gulf Coast, South Texas and other areas) on which it has identified approximately 2,700 drillsites, 1.0 tcfe of proved undeveloped reserves and approximately 1.0 tcfe of unproved reserves;

* 1.1 million net acres in its unconventional gas resource areas (i.e., Sahara, Granite/Cherokee/Atoka Washes, Hartshorne CBM, Barnett Shale and Ark-La-Tex tight sands) on which it has identified approximately 14,000 drillsites, 1.3 tcfe of proved undeveloped reserves and approximately 4.2 tcfe of unproved reserves;

* 1.2 million net acres in its emerging gas resource areas (i.e., Fayetteville Shale, Caney/Woodford Shales, Deep Haley, Deep Bossier and others) on which it has identified approximately 2,000 drillsites, 0.1 tcfe of proved undeveloped reserves and approximately 1.9 tcfe of unproved reserves; and

* 3.3 million net acres in the Appalachian Basin, where play types range from conventional to unconventional to emerging gas resource. On its significant Appalachian Basin acreage base acquired from CNR in November 2005, Chesapeake has identified approximately 9,200 drillsites, 0.4 tcfe of proved undeveloped reserves and more than 1.7 tcfe of unproved reserves.

Chesapeake continues to actively acquire more acreage throughout its operating areas with more than 1.4 million acres acquired in 2005, of which almost 500,000 acres was acquired in the 2005 fourth quarter through an aggressive land acquisition program that is currently utilizing more than 900 contract landmen in the field.

Chesapeake's most significant land acquisition activities during the quarter took place in the Arkansas Fayetteville Shale and Deep Bossier plays in which today the company owns 1,000,000 net acres and 125,000 net acres, respectively. To date, Chesapeake has drilled four vertical wells in the Fayetteville Shale and is preparing to complete its first horizontal well. The company has two rigs dedicated to exploring its Fayetteville Shale acreage position, and if results are encouraging, the company plans to increase its drilling activity during 2006. Chesapeake will drill its first Deep Bossier well in East Texas later this year.

Balance Sheet Continues to Strengthen in 2005

As of December 31, 2005, Chesapeake's long-term debt was $5.490 billion and its stockholders' equity was $6.174 billion, for a debt-to-total capitalization ratio of 47%, compared to a debt-to-total capitalization ratio of 49% at year-end 2004. At year-end 2005, the company's estimated proved reserves were 7.5 tcfe, for long-term debt per mcfe of proved reserves of $0.73, compared to $0.63 per mcfe at year-end 2004 and $0.65 per mcfe at year- end 2003. We believe the growth in operating margins and cash flows per mcfe we have experienced from 2003 to 2005 more than compensate for the modest increase in debt per mcfe. Operating income per mcfe during this three-year period has increased from $2.52 per mcfe in 2003 to $2.74 per mcfe in 2004 and $3.78 per mcfe in 2005. Given Chesapeake's strong reserve replacement record through the drillbit and through acquisitions, low operating costs and high returns on invested capital, the company believes that it can continue to strengthen its balance sheet in the years ahead.

In February 2006, Chesapeake increased its financial flexibility by amending its secured revolving bank credit facility to increase the aggregate commitments under the facility from $1.25 billion to $2.0 billion and to extend the maturity to February 2011.

Chesapeake's Timely Drilling Rig Investments Deliver Operational, Acquisition and Financial Rewards

In anticipation of today's tight drilling rig market, Chesapeake began making a series of investments in drilling rigs in 2001. In that year, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. Chesapeake has invested a total of $123 million in Nomac's 19 operating rigs, invested another $26 million in 25 rigs that Nomac is currently building, and budgeted an additional $191 million for completion of these rigs.

In addition to Nomac, Chesapeake has also made four other major drilling rig investments. The first of these was its ownership of approximately 17% of the common stock of Pioneer Drilling Corporation , which it began acquiring in 2003. The company recently sold its PDC stock, realizing proceeds of $159 million and a pre-tax profit of $116 million that it will recognize in the 2006 first quarter. Chesapeake then re-invested the PDC proceeds to acquire 13 rigs from privately held Martex Drilling Company, L.L.P. for $150 million. The company believes it was able to acquire the Martex rigs at an approximate 33% discount to the stock market valuation of PDC's rigs.

Chesapeake has invested $43 million in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns 45% and 49%, respectively. DHS owns ten rigs and has five more rigs on order. Mountain owns one rig and has ordered another nine rigs for delivery in 2006 and 2007. Chesapeake's rig investments have served as a partial hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely basis.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "Today's announcement of very strong operational and financial results for the fourth quarter and full-year 2005 provides compelling evidence that Chesapeake's business strategy continues to create substantial growth and investor value while also significantly mitigating risk through our proactive commodity price and service cost hedging initiatives.

"The year 2005 marks our most successful year to date. In addition to achieving a record level of proved reserves, production, net income to common shareholders, cash flow and ebitda, Chesapeake's 12% organic growth rate and 659% reserve replacement at an attractive drilling and acquisition cost of $1.74 per mcfe were among the very best of all large-cap public E&P companies.

"In addition, we made a series of value-added acquisitions during 2005, capped off by our $3 billion acquisition of Columbia Natural Resources, a dominant producer and leasehold owner in the Appalachian Basin. We have nearly completed the integration of CNR's operations and are preparing to significantly increase our Appalachian drilling activity. Furthermore, we anticipate continuing to take advantage of our attractively priced oil and natural gas hedges and our deep backlog of drilling projects by increasing our drilling rig count during the year from its current level of 76 to 100 or more, with exact levels of future activity determined by natural gas prices, service costs and other factors.

"The company's business strategy has worked very well for investors. Since our IPO on February 4, 1993, we have delivered an approximate 2,300% increase in our common stock price during the past 13 years. Our business strategy features delivering growth through a balance of acquisitions and organic drilling, focusing on natural gas to take advantage of strong long- term natural gas supply/demand fundamentals, building dominant regional scale to achieve low operating costs and high returns on capital and successfully mitigating risk through the opportunistic hedging of commodity prices and service costs. We believe Chesapeake's management team can continue the successful execution of the company's distinctive business strategy and continue to deliver significant investor value for years to come."

Conference Call Information

A conference call has been scheduled for Friday morning, February 24, 2006 at 9:00 a.m. EST to discuss this release. The telephone number to access the conference call is 913.981.5543 and the confirmation code is 3471819. For those unable to participate in the conference call, a replay will be available from 12:00 p.m. EST, February 24, 2006 through midnight EST on March 9, 2006. The number to access the conference call replay is 719.457.0820 and the passcode for the replay is 3471819. The conference call will also be simulcast live on the Internet and can be accessed at http://www.chkenergy.com/ by selecting "Conference Calls" under the "Investor Relations" section. The webcast of the conference call will be available on the 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 gas reserves, expected oil and gas production and future expenses, projections of future oil and 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.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our prospectus supplement dated December 8, 2005 filed with the Securities and Exchange Commission on December 12, 2005. They include the volatility of oil and gas prices; adverse effects our level of indebtedness and preferred stock could have on our operations and future growth; our ability to compete effectively against strong independent oil and gas companies and majors; the availability of capital on an economic basis to fund reserve replacement costs; uncertainties inherent in estimating quantities of oil and gas reserves and projecting future rates of production and the timing of development expenditures; our ability to replace reserves and sustain production; uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities; our ability to operate successfully in the Appalachian Basin and integrate newly acquired Columbia Natural Resources into our business; unsuccessful exploration and development drilling; declines in the values of our oil and gas properties resulting in ceiling test write-downs; lower prices realized on oil and gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities; and drilling and operating risks. We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this press release, and we undertake no obligation to update this information.

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 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 terms "probable", "possible" or "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 second 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 http://www.chkenergy.com/ .

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

	Three Months Ended December 31, 2005		Three Months Ended December 31, 2004	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and gas sales	1,240,314	9.51	665,782	6.47
Oil and gas marketing sales	510,665	3.92	276,269	2.68
Total Revenues	1,750,979	13.43	942,051	9.15
OPERATING COSTS:				
Production expenses	94,296	0.72	56,321	0.55
Production taxes	71,585	0.55	35,372	0.34
General and administrative expenses	24,632	0.19	9,973	0.10
Oil and gas marketing expenses	497,214	3.82	269,109	2.61
Oil and gas depreciation, depletion and amortization	272,551	2.09	171,900	1.67
Depreciation and amortization of other assets	16,175	0.12	9,030	0.09
Provision for legal settlements	---	---	4,500	0.04
Total Operating Costs	976,453	7.49	556,205	5.40
INCOME FROM OPERATIONS	774,526	5.94	385,846	3.75
OTHER INCOME (EXPENSE):				
Interest and other income	2,662	0.02	913	0.01
Interest expense	(64,177)	(0.49)	(43,288)	(0.42)
Loss on repurchases or exchanges of Chesapeake debt	(372)	(0.01)	(17,632)	(0.17)
Total Other Income (Expense)	(61,887)	(0.48)	(60,007)	(0.58)
Income Before Income Taxes	712,639	5.46	325,839	3.17
Income Tax Expense:				
Current	---	---	---	---
Deferred	260,114	1.99	117,301	1.14
Total Income Tax Expense	260,114	1.99	117,301	1.14
NET INCOME	452,525	3.47	208,538	2.03
Preferred stock dividends	(16,287)	(0.13)	(8,707)	(0.08)
Loss on conversion/exchange of preferred stock	(4,406)	(0.03)	(36,678)	(0.36)
NET INCOME AVAILABLE TO				

COMMON SHAREHOLDERS	431,832	3.31	163,153	1.59

EARNINGS PER COMMON SHARE:

Basic	$ 1.25	$ 0.59
Assuming dilution	$ 1.11	$ 0.52

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

Basic	344,614	277,410
Assuming dilution	403,730	328,029

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

	Twelve Months Ended December 31, 2005		Twelve Months Ended December 31, 2004	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and gas sales	3,272,585	6.98	1,936,176	5.34
Oil and gas marketing sales	1,392,705	2.97	773,092	2.13
Total Revenues	4,665,290	9.95	2,709,268	7.47
OPERATING COSTS:				
Production expenses	316,956	0.68	204,821	0.56
Production taxes	207,898	0.44	103,931	0.29
General and administrative expenses	64,272	0.14	37,045	0.10
Oil and gas marketing expenses	1,358,003	2.89	755,314	2.08
Oil and gas depreciation, depletion and amortization	894,035	1.91	582,137	1.61
Depreciation and amortization of other assets	50,966	0.11	29,185	0.08
Provision for legal settlements	---	---	4,500	0.01
Total Operating Costs	2,892,130	6.17	1,716,933	4.73
INCOME FROM OPERATIONS	1,773,160	3.78	992,335	2.74
OTHER INCOME (EXPENSE):				
Interest and other income	10,452	0.02	4,476	0.01
Interest expense	(219,800)	(0.46)	(167,328)	(0.46)
Loss on repurchases or exchanges of Chesapeake debt	(70,419)	(0.15)	(24,557)	(0.07)
Total Other Income (Expense)	(279,767)	(0.59)	(187,409)	(0.52)
Income Before Income Taxes	1,493,393	3.19	804,926	2.22
Income Tax Expense:				
Current	---	---	---	---

Deferred	545,091	1.17	289,771	0.80
Total Income Tax Expense	545,091	1.17	289,771	0.80
NET INCOME	948,302	2.02	515,155	1.42
Preferred stock dividends	(41,813)	(0.09)	(39,506)	(0.11)
Loss on conversion/exchange of preferred stock	(26,874)	(0.05)	(36,678)	(0.10)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	879,615	1.88	438,971	1.21

EARNINGS PER COMMON SHARE:

Basic	$ 2.73	$ 1.73
Assuming dilution	$ 2.51	$ 1.53

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

Basic	322,034	253,212
Assuming dilution	366,683	305,718

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

	December 31, 2005	December 31, 2004
Cash	$60,027	$6,896
Other current assets	1,123,370	560,644
Total Current Assets	1,183,397	567,540
Property and equipment (net)	14,411,887	7,444,384
Other assets	523,178	232,585
Total Assets	$16,118,462	$8,244,509
Current liabilities	$1,964,088	$963,953
Long term debt	5,489,742	3,075,109
Asset retirement obligation	156,593	73,718
Other long term liabilities	528,738	34,973
Deferred tax liability	1,804,978	933,873
Total Liabilities	9,944,139	5,081,626
STOCKHOLDERS' EQUITY	6,174,323	3,162,883
TOTAL LIABILITIES & STOCKHOLDERS' EQUITY	$16,118,462	$8,244,509
COMMON SHARES OUTSTANDING	370,190	311,869

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF 2005 COSTS INCURRED
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs (A)	$1,820,071	1,046,767	$1.74
Acquisition of proved properties	3,554,651	2,041,235	1.74
Subtotal	5,374,722	3,088,002	1.74
Acquisition of unproved properties	1,375,675	---	---
Divestitures	(9,769)	(486)	---
Leasehold acquisition costs	290,946	---	---
Geological and geophysical costs	70,901	---	---
Adjusted subtotal	7,102,475	3,087,516	2.30
Tax basis step-up	251,722	---	---
Asset retirement obligation and other	52,619	---	---
Total	$7,406,816	3,087,516	$2.40

(A) Reserves include revisions to previous estimates

CHESAPEAKE ENERGY CORPORATION
ROLL-FORWARD OF PROVED RESERVES
(unaudited)

	Mmcfe
Beginning balance, 12/31/04	4,901,751
Extensions and discoveries	1,005,564
Acquisitions	2,041,235
Divestitures	(486)
Revisions - performance	16,729
Revisions - price	24,474
Production	(468,577)
Ending balance, 12/31/05	7,520,690
Reserve replacement	3,087,516
Reserve replacement rate	659%

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

Three Months Ended December 31,	Twelve Months Ended December 31,

	2005	2004	2005	2004
Oil and Gas Sales ($ in thousands):				
Oil Sales	$111,513	$79,033	$401,845	$260,915
Oil derivatives - realized gains (losses)	(5,478)	(27,595)	(34,132)	(69,267)
Oil derivatives - unrealized gains (losses)	10,325	25,379	4,374	3,454
Total Oil Sales	116,360	76,817	372,087	195,102
Gas Sales	1,225,616	566,492	3,231,286	1,789,275
Gas derivatives - realized gains (losses)	(269,596)	(59,658)	(367,551)	(85,634)
Gas derivatives - unrealized gains (losses)	167,934	82,131	36,763	37,433
Total Gas Sales	1,123,954	588,965	2,900,498	1,741,074
Total Oil and Gas Sales	$1,240,314	$665,782	$3,272,585	$1,936,176
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$55.37	$44.10	$52.20	$38.57
Gas ($ per mcf)	$10.36	$ 6.15	$ 7.65	$ 5.56
Gas equivalent ($ per mcfe)	$10.25	$ 6.27	$ 7.75	$ 5.65
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$52.65	$28.70	$47.77	$28.33
Gas ($ per mcf)	$ 8.08	$ 5.50	$ 6.78	$ 5.29
Gas equivalent ($ per mcfe)	$ 8.14	$ 5.42	$ 6.90	$ 5.23
Interest Expense ($ in thousands)				
Interest	$66,121	$44,446	$226,330	$162,781
Derivatives - realized (gains) losses	(2,306)	(607)	(4,945)	(791)
Derivatives - unrealized (gains) losses	362	(551)	(1,585)	5,338
Total Interest Expense	$64,177	$43,288	$219,800	$167,328

CHESAPEAKE ENERGY CORPORATION
CONDENSED CONSOLIDATED CASH FLOW DATA

(in 000's)
(unaudited)

THREE MONTHS ENDED:	December 31, 2005	December 31, 2004
Cash provided by operating activities	$829,543	$394,256
Cash (used in) investing activities	(3,362,450)	(712,963)
Cash provided by financing activities	2,465,832	276,530

TWELVE MONTHS ENDED:	December 31, 2005	December 31, 2004
Cash provided by operating activities	$2,406,888	$1,432,274
Cash (used in) investing activities	(7,017,494)	(3,381,204)
Cash provided by financing activities	4,663,737	1,915,245

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

THREE MONTHS ENDED:	Dec. 31, 2005	Sept. 30, 2005	Dec. 31, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$829,543	$557,428	$394,256
Adjustments:			
Changes in assets and liabilities	3,250	77,150	13,330
OPERATING CASH FLOW*	$832,793	$634,578	$407,586

* 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 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 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:	Dec. 31, 2005	Sept. 30, 2005	Dec. 31, 2004
NET INCOME	$452,525	$176,988	$208,538
Income tax expense	260,114	101,734	117,301
Interest expense	64,177	58,593	43,288
Depreciation and amortization of other assets	16,175	12,902	9,030
Oil and gas depreciation, depletion and amortization	272,551	231,145	171,900
EBITDA**	$1,065,542	$581,362	$550,057

** Ebitda represents net income (loss) before cumulative effect of accounting change, income tax expense (benefit), 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:	Dec. 31, 2005	Sept. 30, 2005	Dec. 31, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$829,543	$557,428	$394,256
Changes in assets and liabilities	3,250	77,150	13,330
Interest expense	64,177	58,593	43,288
Unrealized gains (losses) on oil and gas derivatives	178,259	(104,049)	107,510
Other non-cash items	(9,687)	(7,760)	(8,327)
EBITDA	$1,065,542	$581,362	$550,057

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

(unaudited)

TWELVE MONTHS ENDED:	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	$2,406,888	$1,432,274	$938,907
Adjustments:			
Changes in assets and liabilities	18,839	(29,752)	(41,673)
OPERATING CASH FLOW*	$2,425,727	$1,402,522	$897,234

* 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 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 gas exploration and production industry. Operating cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing, or financing activities as an indicator of cash flows, or as a measure of liquidity.

TWELVE MONTHS ENDED:	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003
NET INCOME	$948,302	$515,155	$312,981
Income tax expense	545,091	289,771	190,360
Interest expense	219,800	167,328	154,356
Depreciation and amortization of other assets	50,966	29,185	16,793
Oil and gas depreciation, depletion and amortization	894,035	582,137	396,465
Cumulative effect of accounting changes	---	---	(2,389)
EBITDA**	$2,658,194	$1,583,576	$1,041,566

** Ebitda represents net income (loss) before cumulative effect of accounting change, income tax expense (benefit), interest expense, and depreciation, depletion and amortization expense. Ebitda is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Ebitda is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreement and is used in the financial covenants in our bank credit agreement and our senior note indentures. Ebitda is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP. Ebitda is reconciled to cash provided by operating activities as follows:

TWELVE MONTHS ENDED:	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003
CASH PROVIDED BY OPERATING ACTIVITIES	$2,406,888	$1,432,274	$938,907
Changes in assets and liabilities	18,839	(29,752)	(41,673)
Interest expense	219,800	167,328	154,356
Unrealized gains (losses) on oil and gas derivatives	41,137	40,887	10,531
Other non-cash items	(28,470)	(27,161)	(20,555)
EBITDA	$2,658,194	$1,583,576	$1,041,566

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

	Three Months Ended December 31, 2005	Twelve Months Ended December 31, 2005
Net income available to common shareholders	$431,832	$879,615
Adjustments:		
Loss on conversion/exchange of preferred stock	4,406	26,874
Net Income	$436,238	$906,489
Adjustments, net of tax:		
Unrealized (gains) losses on derivatives	(112,965)	(27,128)
Loss on repurchases or exchanges of debt	236	44,716
Adjusted net income available to common shareholders*	$323,509	$924,077
Adjusted earnings per share assuming dilution**	$0.84	$2.57

* 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 gas producing companies.
b. Adjusted net income available to common are 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.

** For purposes of calculating fully diluted shares and earnings per share assuming dilution for the three months ended December 31, 2005, accounting rules prohibit the company from assuming the conversion of the 5.0% (Series 2003) and the 4.125% preferred stock for common shares prior to conversion or exchange since the effect would have been anti-dilutive. For purposes of calculating fully diluted shares and earnings per share assuming dilution for the twelve months ended December 31, 2005, accounting rules prohibit the company from assuming the conversion of the 4.125% preferred stock for common shares prior to conversion or exchange since the effect would have been anti-dilutive. In determining adjusted earnings per share, we have reflected the converted shares as though they were converted at the beginning of the period (fully diluted share count of 404.8 million and 375.3 million for the three and twelve months ended December 31, 2005, respectively).

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF PV-10
($ in 000's)
(unaudited)

	December 31, 2005	December 31, 2004
Standardized measure of discounted future net cash flows (SMOG)	$15,967,911	$7,645,539
Discounted future cash flows for income taxes	6,965,683	2,858,851
Discounted future net cash flows before income taxes (PV-10)	$22,933,594	$10,504,390

PV-10 is discounted (at 10%) future net cash flows before income taxes. The standardized measure of discounted future net cash flows includes the effects of estimated future income tax expenses and is calculated in accordance with SFAS 69. Management uses PV-10 as one measure of the value of the company's current proved reserves and to compare relative values among peer companies without regard to income taxes. We also understand that securities analysts and rating agencies use this measure in similar ways. While PV-10 is based on prices, costs and discount factors which are consistent from company to company, the standardized measure is dependent on the unique tax situation of each individual company.

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

THREE MONTHS ENDED:	December 31, 2005	September 30, 2005	December 31, 2004
EBITDA	$1,065,542	$581,362	$550,057
Adjustments, before tax:			
Unrealized (gains) losses on oil and gas derivatives	(178,259)	104,049	(107,510)
Loss on repurchases or exchanges of debt	372	747	17,632
Provision for legal settlement	---	---	4,500
Adjusted EBITDA*	$887,655	$686,158	$464,679

TWELVE MONTHS ENDED:	December 31, 2005	December 31, 2004	December 31, 2003
EBITDA	$2,658,194	$1,583,576	$1,041,566
Adjustments, before tax:			
Unrealized (gains) losses on oil and gas derivatives	(41,137)	(40,887)	(10,531)
Loss on repurchases or exchanges of debt	70,419	24,557	20,759
Provision for legal settlement	---	4,500	6,402
Adjusted EBITDA*	$2,687,476	$1,571,746	$1,058,196

* 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 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 FEBRUARY 23, 2006

Quarter Ending March 31, 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 February 23, 2006, we are using the following key assumptions in our projections for the first quarter of 2006, the full-year 2006 and the full- year 2007.

The primary changes from our January 17, 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 since our January 17, 2006 Outlook.
2) We have updated our expectations for future NYMEX oil and gas prices based on current market conditions in order to illustrate hedging effects only.
3) We have updated the share count for the effect of accelerating the stock-based awards to our former Chief Operating Officer; however, we have not reflected the impact to stock-based compensation that will occur in the 2006 first quarter or full year.
4) We have not reflected the gain related to the sale of our investment in Pioneer Drilling Company in other income for the 2006 first quarter or full year.
5) We have updated the book tax rate for 2006 and 2007 primarily to account for the impact of state income taxes associated with our newly acquired Appalachian operations.

	Quarter Ending 3/31/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production:			
Oil - Mbbl	1,900	7,700	7,750
Gas - Bcf	121-131	530-540	572-582
Gas Equivalent - Bcfe	132-142	576-586	619-629
Daily gas equivalent midpoint -in Mmcfe	1,522	1,593	1,709
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bbl	$58.51	$54.00	$50.00
Gas - $/Mcf	$9.47	$7.99	$7.00
Estimated Realized Hedging Effects (based on assumed NYMEX prices above):			
Oil - $/Bbl	$0.96	$4.51	$2.77
Gas - $/Mcf	$1.54	$1.40	$1.34
Estimated Differentials to NYMEX Prices:			

Oil - $/Bbl	6-8%	6-8%	6-8%
Gas - $/Mcf	10-15%	8-12%	8-12%
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.77-0.82	$0.77-0.82	$0.80-0.85
Production taxes (generally 6.0% of O&G revenues) (A)	$0.48-0.53	$0.41-0.46	$0.36-0.41
General and administrative	$0.15-0.17	$0.14-0.16	$0.14-0.15
Stock-based compensation (non-cash)	$0.07-0.09	$0.08-0.10	$0.10-0.12
DD&A - oil and gas	$2.12-2.18	$2.15-2.20	$2.25-2.30
Depreciation of other assets	$0.14-0.16	$0.14-0.16	$0.14-0.16
Interest expense (B)	$0.52-0.57	$0.52-0.57	$0.53-0.58
Other Income and Expense per Mcfe:			
Marketing and other income	$0.02-0.04	$0.02-0.04	$0.02-0.04
Book Tax Rate (approximately equal to 95% deferred)	38%	38%	38%
Equivalent Shares Outstanding:			
Basic	368 mm	374 mm	381 mm
Diluted	431 mm	435 mm	440 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$650-700 mm	$3,000-3,200 mm	$3,300-3,500 mm

(A) Severance tax per mcfe is based on NYMEX prices of $58.51 per bo and natural gas prices ranging from $9.00 to $10.00 per mcf during Q1 2006, $54.00 per bo and $7.50 to $8.50 per mcf during calendar 2006 and $50.00 per bo and $6.50 to $7.50 per mcf during calendar 2007.

(B) 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 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 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 gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and 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 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 in place the following natural gas swaps:

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Avg. Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	% Hedged Assuming Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Gas Production
2006:						
Q1	93.8	$10.81	-$0.09	$10.72	126.0	74%
Q2	96.9	$8.88	-$0.06	$8.82	132.0	73%
Q3	101.7	$8.93	-$0.06	$8.87	137.0	74%
Q4	90.0	$9.41	-$0.05	$9.36	140.0	64%
Total 2006(A)	382.4	$9.49	-$0.06	$9.43	535.0	71%
Total 2007	206.9	$9.91	-$0.06	$9.85	577.0	36%
Total 2008	131.8	$9.10	---	$9.10	604.0	22%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 43.0 bcf in 2006.

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 $10.57 and 7.3 bcf of production in 2008 at a weighed average price of $12.50.

The company has also entered into the following natural gas basis protection swaps:

	Volume in Bcf's	NYMEX less*:	Assuming Gas Production in Bcf's of:	% Hedged
2006	130.1	$0.32	535	24%
2007	137.2	0.33	577	24%
2008	118.6	0.27	604	20%
2009	86.6	0.29	634	14%
Totals	472.5	$0.30	2,350	20%

* weighted average

The company has entered into the following crude oil hedging arrangements:

	Open Swaps in mbo's	Avg. NYMEX Strike Price	% Hedged Assuming Oil Production in mbo's of:	Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	$60.03	1,900.0	58%
Q2	1,289.5	$61.13	1,920.0	67%
Q3	1,242.0	$61.50	1,940.0	64%
Q4	1,196.0	$61.33	1,940.0	62%
Total 2006(A)	4,837.0	$61.02	7,700.0	63%
Total 2007	1,730.0	$62.42	7,750.0	22%
Total 2008	1,098.0	$65.48	7,800.0	14%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $42.00 covering 501.5 mbo in 2006.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability as do other liabilities assumed in connection with the acquisition resulted in an increase in the total purchase price which is 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 will result in adjustments to our oil and gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do 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 gas revenues related to the derivative positions. If, however, the actual sales price is different than the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and 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 have 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 acquisitions are deemed to contain a significant financing element and all cash flows associated with these positions will be reported as financing activity in the statement of cash flows.

The following details in 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 (per Mcf)	Assuming Gas Acquired Production in Bcf's of: Total Gas Production	% Hedged Open Swap Positions as a % of Estimated
2006:						
Q1	7.9	$4.91	$12.14	($7.23)	126.0	6%
Q2	10.5	$4.86	$9.97	($5.11)	132.0	8%
Q3	10.6	$4.86	$9.95	($5.09)	137.0	8%
Q4	10.6	$4.86	$10.38	($5.52)	140.0	8%
Total 2006	39.6	$4.87	$10.51	($5.64)	535.0	7%
Total 2007	42.0	$4.82	$9.18	($4.36)	577.0	7%
Total 2008	38.4	$4.67	$8.01	($3.34)	604.0	6%
Total 2009	18.3	$5.18	$7.28	($2.10)	634.0	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.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF JANUARY 17, 2006
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF FEBRUARY 23, 2006

Quarter Ending March 31, 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 January 17, 2006, we are using the following key assumptions in our projections for the first quarter of 2006, the full-year 2006 and the full-year 2007.

The primary changes from our December 6, 2005 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 since our December 6, 2005 Outlook.
2) We have updated our expectations for future NYMEX oil and gas prices based on current market conditions in order to illustrate hedging effects only.
3) We have included the effects of the financing completed in December 2005 as well as conversions of preferred stock to common stock since December 6, 2005.
4) We have updated for operational and financial effects of the acquisitions and anticipated financing of these acquisitions as described in our press release dated January 17, 2006.
5) We have shown our projections for the quarter ending March 31, 2006 for the first time.

	Quarter Ending 3/31/2006	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production:			
Oil - Mbo	1,900	7,700	7,750
Gas - Bcf	121-131	530-540	572-582
Gas Equivalent - Bcfe	132-142	576-586	619-629
Daily gas equivalent midpoint - in Mmcfe	1,522	1,593	1,709
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bo	$56.67	$53.54	$50.00
Gas - $/Mcf	$9.48	$8.00	$7.00
Estimated Differentials to NYMEX Prices:			
Oil - $/Bo	6-8%	6-8%	6-8%
Gas - $/Mcf	10-15%	8-12%	8-12%
Estimated Realized Hedging Effects (based on expected NYMEX prices above):			
Oil - $/Bo	$2.00	$3.88	$1.45
Gas - $/Mcf	$1.51	$1.12	$0.87
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.75-0.80	$0.77-0.82	$0.80-0.85
Production taxes (generally 6.5% of O&G revenues) (A)	$0.52-0.56	$0.45-0.50	$0.40-0.45
General and administrative	$0.11-0.13	$0.11-0.13	$0.11-0.13
Stock-based compensation (non-cash)	$0.07-0.09	$0.08-0.10	$0.10-0.12
DD&A - oil and gas	$2.12-2.18	$2.15-2.20	$2.25-2.30
Depreciation of other assets	$0.10-0.12	$0.10-0.12	$0.11-0.13
Interest expense (B)	$0.52-0.57	$0.52-0.57	$0.53-0.58
Other Income and Expense per Mcfe:			
Marketing and other income	$0.02-0.04	$0.02-0.04	$0.02-0.04

Book Tax Rate (approximately

equal to 95% deferred)	36.5%	36.5%	36.5%
Equivalent Shares Outstanding:			
Basic	365 mm	366 mm	371 mm
Diluted	431 mm	432 mm	436 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$575-625 mm	$2,800-3,000 mm	$3,100-3,300 mm

(A) Severance tax per mcfe is based on NYMEX prices of $57.50 per bo and natural gas prices ranging from $9.00 to $9.80 per mcf during Q1 2006, $53.00 per bo and $7.50 to $8.50 per mcf during calendar 2006 and $50.00 per bo and $6.65 to $7.65 per mcf during calendar 2007.
(B) 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 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 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 gas sales. All realized gains and losses from oil and natural gas derivatives are included in oil and 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 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.

We have not reflected any of the derivative positions acquired from CNR in the following tables. We have recorded such positions at fair value in the purchase price allocation as a liability on the date of acquisition. Changes in fair value subsequent to the acquisition date for the derivative positions assumed will result in adjustments to our oil and gas revenues only upon cash settlement and only to the extent the cash settlement differs from the original liability recorded.

The company currently has in place the following natural gas swaps:

% Hedged

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Avg. Gain (Loss) from Locked Swaps	Avg. NYMEX Price Including Open & Locked Positions	Assuming Gas Production in Bcf's of:	Open Swap Positions as a % of Estimated Total Gas Production
2006:						
Q1	93.5	$10.81	-$0.09	$10.72	126.0	74%
Q2	75.5	$8.79	-$0.08	$8.71	132.0	57%
Q3	76.4	$8.79	-$0.07	$8.72	137.0	56%
Q4	64.7	$9.08	-$0.07	$9.01	140.0	46%
Total 2006(A)	310.1	$9.46	-$0.08	$9.38	535.0	58%
Total 2007	131.2	$9.81	-$0.09	$9.72	577.0	23%
Total 2008	78.7	$8.82	---	$8.82	604.0	13%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 43.0 bcf in 2006.

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, 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 also entered into the following natural gas basis protection swaps:

	Volume in Bcf's	NYMEX less*:	Assuming Gas Production in Bcf's of:	% Hedged
2006	130.1	$0.32	535	24%
2007	137.2	0.33	577	24%

2008	118.6	0.27	604	20%
2009	86.6	0.29	634	14%
Totals	472.5	$0.30	2,350	20%

* weighted average

The company has entered into the following crude oil hedging arrangements:

	Open Swaps in mbo's	Avg. NYMEX Strike Price	% Hedged Assuming Oil Production in mbo's of:	Open Swap Positions as % of Total Estimated Production
2006:				
Q1	1,109.5	$60.03	1,900.0	58%
Q2	1,153.0	$60.27	1,920.0	60%
Q3	1,104.0	$60.56	1,940.0	57%
Q4	1,058.0	$60.30	1,940.0	55%
Total 2006(A)	4,424.5	$60.29	7,700.0	57%
Total 2007	1,182.5	$59.79	7,750.0	15%
Total 2008	549.0	$63.94	7,800.0	7%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $40.00 to $42.00 covering 501.5 mbo in 2006.

SOURCE: Chesapeake Energy Corporation

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