NEWS
RELEASE

Chesapeake Energy Corporation Reports Strong Operating and Financial Results for the 2005 Third Quarter

Company Reports 2005 Third Quarter Net Income Available to Common Shareholders of $149 Million on Revenue of $1.1 Billion and Production of 120 Bcfe
Oil and Natural Gas Production Reaches 1.308 Bcfe per Day, a 28% Increase Over 2004 Third Quarter and 5% Over 2005 Second Quarter; 2005 Total Production Growth Expected to Exceed 25%; 2005 and 2006 Organic Growth Expected to Exceed 10%; Initial 2007 Organic Growth Estimated at 7%
Pro Forma for Pending CNR Acquisition, Proved Reserves Reach 7.3 Tcfe and Total Reserves Reach 14 Tcfe; First Nine Months 2005 Proved Reserve Adds Total 1.3 Tcfe; Reserve Replacement Equals 488% at Attractive Drilling and Acquisition Cost of $1.47 Per Mcfe

PRNewswire-FirstCall
OKLAHOMA CITY

Chesapeake Energy Corporation today reported financial and operating results for the third quarter of 2005. For the quarter, Chesapeake generated net income available to common shareholders of $149.1 million ($0.43 per fully diluted common share), operating cash flow of $635.2 million (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $581.4 million (defined as income before income taxes, interest expense, and depreciation, depletion and amortization expense) on revenue of $1.083 billion and production of 120.4 billion cubic feet of natural gas equivalent (bcfe).

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

* an unrealized mark-to-market loss of $66.8 million resulting from the company's oil, natural gas and interest rate hedging programs;

* a $0.5 million loss resulting from the early extinguishment of certain Chesapeake debt securities; and

* a reduction of net income available to common shareholders of $17.7 million resulting from a loss on the exchange of approximately $134 million of Chesapeake's 4.125% cumulative convertible preferred stock into 8.5 million shares of the company's common stock and $70 million of Chesapeake's 5.0% (series 2003) cumulative convertible preferred stock into 4.4 million shares of the company's common stock through unsolicited transactions with holders of the preferred stock.

Adjusted for the above-mentioned items, Chesapeake's net income to common shareholders in the 2005 third quarter would have been $234.1 million ($0.65 per fully diluted common share) and ebitda would have been $686.2 million. 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 available to common shareholders to comparable financial measures calculated in accordance with generally accepted accounting principles is presented on pages 13-15 of this release.

Oil and Natural Gas Production Sets Record for 17th Consecutive Quarter; 2005 Third Quarter Average Daily Production Increases 28% Over 2004 Third Quarter and 5% Over 2005 Second Quarter

Daily production for the 2005 third quarter averaged 1.308 bcfe, an increase of 284 million cubic feet of natural gas equivalent (mmcfe), or 27.7%, over the 1.024 bcfe produced per day in the 2004 third quarter and an increase of 64 mmcfe, or 5.1%, over the 1.244 bcfe produced per day in the 2005 second quarter. Of the 64 mmcfe daily increase in sequential quarterly production, 53% came from organic growth and 47% from acquisition growth, making the company's quarterly organic growth rate 2.9%, its year-to-date organic growth rate 8.0% and its annualized 2005 organic growth rate 10.7%. The company's 2005 third quarter production exceeded its September 7, 2005 forecasted mid-point production by 0.9 bcfe, or 0.7%, because of stronger than projected drilling and operational results. The effects of Hurricane Rita reduced Chesapeake's third quarter production by 0.3 bcfe as a result of onshore facility shut-ins.

Chesapeake's 2005 third quarter production of 120.4 bcfe was comprised of 108.8 billion cubic feet of natural gas (bcf) (90% on a natural gas equivalent basis) and 1.93 million barrels of oil and natural gas liquids (10% on a natural gas equivalent basis). Chesapeake's average daily production rate of 1.308 bcfe consisted of 1.183 bcf of gas and 20,935 barrels of oil and natural gas liquids (bbl).

The 2005 third quarter was Chesapeake's 17th consecutive quarter of production growth. During these 17 quarters, Chesapeake's U.S. production has increased 234%, for an average compound quarterly growth rate of 7.4% and an average compound annual growth rate of 33%.

Oil and Natural Gas Proved Reserves Reach Record Level of 6.2 Tcfe; First Nine Months 2005 Drilling and Acquisition Costs are $1.47 per Mcfe as Company Adds 1.311 Tcfe and Replaces Production by 488%

Chesapeake began 2005 with estimated proved reserves of 4.902 trillion cubic feet of natural gas equivalent (tcfe) and ended the third quarter with an internally estimated 6.213 tcfe, an increase of 1.311 tcfe, or 27%. During the 2005 first nine months, the company replaced its 338 bcfe of production with an estimated 1.649 tcfe of new proved reserves, for a reserve replacement rate of 488% at a drilling and acquisition cost of $1.47 per mcfe. Reserve replacement through the drillbit was 929 bcfe, or 275% of production (including a negative 19 bcfe from performance revisions and a positive 94 bcfe from oil and natural gas price increases), or 56% of the total increase, at a cost of $1.42 per mcfe. Reserve replacement through acquisitions was 720 bcfe, or 213% of production, or 44% of the total increase, at a cost of $1.54 per mcfe. The above figures do not include the impact of the pending CNR acquisition, which should close by December 1, 2005 and will increase Chesapeake's proved reserves by an internally estimated 1.1 tcfe.

Total costs incurred to acquire and develop proved reserves during the first nine months of 2005 were $2.23 per mcfe. These total costs include drilling, completion, acquisition, seismic, leasehold, capitalized internal costs, non-cash tax basis step-up from various corporate acquisitions ($253 million, or $0.15 per mcfe), asset retirement obligations and all other capitalized miscellaneous costs. These costs exclude future development costs of proved undeveloped reserves, but include costs associated with acquisition of unproved properties on which proved reserves have not been booked. A complete reconciliation of finding and acquisition cost information and a roll-forward of proved reserves is presented on page 11 of this release.

As of September 30, 2005, the company's estimated future net cash flows discounted at 10% before taxes (PV-10) from its proved reserves were $28.6 billion using field differential adjusted prices of $62.01 per bbl (based on a NYMEX quarter-end price of $66.38 per bbl) and $11.36 per mcf (based on a NYMEX quarter-end price of $14.20 per mcf). Chesapeake's PV-10 changes by approximately $267 million for every $0.10 per mcf change in gas prices and approximately $49 million for every $1.00 per bbl change in oil prices. The above figures do not include the impact of the pending CNR acquisition, which would have added approximately $4.2 billion to the PV-10 total above had Chesapeake owned the CNR assets as of September 30, 2005.

Key Operational and Financial Statistics are Summarized Below
for the 2005 Third and Second Quarters and the 2004 Third Quarter

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

	Three Months Ended		
	9/30/05	6/30/05	9/30/04
Average daily production (in mmcfe)	1,308	1,244	1,024
Gas as % of total production	90	89	88
Natural gas production (in bcf)	108.8	101.1	83.2
Average realized gas price ($/mcf) (A)	6.64	5.95	5.17
Oil production (in mbbls)	1,926	2,012	1,834
Average realized oil price ($/bbl) (A)	53.30	42.82	29.15
Natural gas equivalent production (in bcfe)	120.4	113.2	94.2
Gas equivalent realized price ($/mcfe) (A)	6.85	6.08	5.13
Net marketing income ($/mcfe)	.07	.05	.04
General and administrative costs ($/mcfe) (B)	(.09)	(.08)	(.09)
Stock-based compensation ($/mcfe)	(.04)	(.02)	(.01)
Production taxes ($/mcfe)	(.44)	(.42)	(.33)
Production expenses ($/mcfe)	(.67)	(.64)	(.57)
Interest expense ($/mcfe) (A)	(.48)	(.48)	(.45)
DD&A of oil and gas properties ($/mcfe)	(1.92)	(1.85)	(1.63)
D & A of other assets ($/mcfe)	(.11)	(.10)	(.08)
Operating cash flow ($ in millions) (C)	635.2	513.3	353.4

Operating cash flow ($/mcfe)	5.28	4.53	3.75
Ebitda ($ in millions) (D)	581.4	580.2	361.3
Ebitda ($/mcfe)	4.83	5.13	3.83
Net income to common shareholders ($ in millions)	149.1	179.2	85.6

(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

Oil and Natural Gas Price Realizations Detailed, Hedging Positions Updated,

Outlooks for 2005 and 2006 Updated and Initial Outlook for 2007 Provided

Average prices realized during the 2005 third quarter (including realized gains or losses from oil and gas derivatives, but excluding unrealized gains or losses on such derivatives) were $53.30 per bbl and $6.64 per thousand cubic feet (mcf), for a realized gas equivalent price of $6.85 per mcfe. Chesapeake's average realized pricing differentials to NYMEX during the third quarter were a negative $4.81 per bbl and a negative $1.14 per mcf. Oil and natural gas hedging activities during the quarter decreased oil and gas sales by $122.6 million, or $5.68 per bbl and $1.03 per mcf, or $1.02 per mcfe.

Chesapeake has added to its 2005, 2006, 2007 and 2008 oil and natural gas hedge positions previously provided in our Outlook dated October 3, 2005. The following tables compare Chesapeake's hedged production volumes through swaps as of October 31, 2005 to those as of October 3, 2005:

Swap Positions as of October 31, 2005

	Oil		Natural Gas	
Quarter or Year	% Hedge	$ NYMEX	% Hedged	$ NYMEX
2005 3Q	46%	$51.66	68%	$6.49
2005 4Q	55%	$54.97	73%	$8.14
2006 1Q	54%	$59.71	55%	$9.89
2006 2Q	53%	$59.60	41%	$8.01
2006 3Q	50%	$59.83	40%	$8.00
2006 4Q	47%	$59.45	34%	$8.21
2006 Total	51%	$59.65	42%	$8.63
2007	8%	$54.29	7%	$9.16
2008	---	---	2%	$8.37

Swap Positions as of October 3, 2005

	Oil		Natural Gas	
Quarter or Year	% Hedged	$ NYMEX	% Hedged	$ NYMEX

2005 3Q	46%	$51.66	68%	$6.49
2005 4Q	55%	$54.97	70%	$7.92
2006 1Q	54%	$59.64	48%	$9.23
2006 2Q	53%	$59.57	35%	$7.60
2006 3Q	50%	$59.85	34%	$7.61
2006 4Q	47%	$59.55	28%	$7.70
2006 Total	51%	$59.65	36%	$8.14
2007	8%	$54.29	3%	$8.28

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 2005, 2006 and 2007 forecasts are attached to this release in an Outlook dated October 31, 2005 labeled as Schedule "A". This Outlook has been changed from the Outlook dated October 3, 2005 (attached as Schedule "B" for investors' convenience) to reflect updated information resulting from the company's operational performance during the third quarter. In addition, the company is providing its initial 2007 forecast, which features projected organic growth of 7% and relatively modest operating cost increases.

Pro forma for Pending CNR Acquisition Company's U.S. Leasehold and 3-D Seismic

Inventories Increase to 8.0 Million and 11.0 Million Net Acres;
Proved and Non-Proven Reserves on the Company's Extensive
Leasehold Now Exceed 14 Tcfe

Chesapeake's exploratory and development drilling programs and production enhancement operations continue to produce operational results that exceed the company's forecasts and distinguish the company among its peers. During the 2005 third quarter, Chesapeake drilled 241 gross (186 net) operated wells and participated in another 278 gross (32 net) wells operated by other companies. The company's drilling success rate was 97% for both company-operated wells and non-operated wells. During the quarter, Chesapeake invested $390 million in operated wells (using an average of 72 operated rigs), $75 million in non- operated wells (using an average of 65 non-operated rigs) and $91 million in acquiring new 3-D seismic data and new leasehold (excluding leasehold acquired through acquisitions).

During the past seven years and pro forma for the pending CNR acquisition, Chesapeake has built what it believes to be the largest inventories of onshore leasehold (8.0 million net acres) and 3-D seismic (11.0 million acres) in the U.S. On this leasehold, the company has identified more than a 10-year inventory of approximately 25,000 drillsites on which it believes it can develop approximately 2.6 tcfe of proved undeveloped reserves and approximately 7.0 tcfe of non-proven reserves.

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 non-proven reserve totals are set forth below:

* 2.6 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 2,300 drillsites, 1.0 tcfe of proved undeveloped reserves and approximately 1.0 tcfe of

non-proven reserves;

* 1.0 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 12,000 drillsites, 1.2 tcfe of proved undeveloped reserves and approximately 3.4 tcfe of non-proven reserves;

* 0.9 million net acres in its emerging gas resource areas (i.e., Fayetteville Shale, Caney/Woodford Shales, Haley Deep and others) on which it has identified approximately 1,200 drillsites, 0.1 tcfe of proved undeveloped reserves and approximately 1.2 tcfe of non-proven reserves; and

* 3.5 million net acres in the Appalachian Basin, where play types range from conventional to unconventional to emerging gas resource. On the significant acreage base it is acquiring from CNR, Chesapeake has identified approximately 9,400 drillsites, 0.3 tcfe of proved undeveloped reserves and more than 1.4 tcfe of non-proven reserves.

Chesapeake continues to actively acquire more acreage throughout its operating areas with almost 500,000 acres acquired in the 2005 third quarter through an aggressive land acquisition program that is utilizing more than 600 landmen in the field. In addition to the pending CNR transaction through which the company will acquire 3.5 million net acres in the U.S. and 0.6 million net acres in Canada, Chesapeake's most significant land acquisition activities during the quarter took place in the Arkansas Fayetteville Shale play where the company has increased its acreage holdings to 600,000 net acres from the 200,000 net acres of leasehold previously disclosed. Chesapeake's initial six-well drilling program in the Fayetteville Shale is now underway.

Management Comments

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "Today's announcement of very strong operational and financial results for the 2005 third quarter provides ongoing confirmation that Chesapeake's business strategy continues to create significant shareholder value. This strategy has generated a 90% increase in our common stock price during the past year and more than a 25-fold increase since our IPO in February 1993 through:

* delivering consistent and value-added growth through a balance of acquisitions and exploratory and developmental drilling;

* focusing on natural gas to take advantage of strong long-term natural gas supply/demand fundamentals; and

* building dominant regional scale to achieve low operating costs and high returns.

We believe Chesapeake's management team can continue the successful execution of the company's distinctive business strategy and continue to deliver significant shareholder value for years to come."

Conference Call Information

A conference call has been scheduled for Tuesday morning, November 1, 2005 at 9:00 a.m. EST to discuss this earnings release. The telephone number to access the conference call is 719.457.2630. For those unable to participate in the conference call, a replay will be available from 12:00 noon EST, November 1, 2005 through midnight EST on Monday, November 14, 2005. The number to access the conference call replay is 719.457.0820 and the passcode is 2076841. 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, including the acquisition of CNR. 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 item 1 of our 2004 Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 9, 2005. They include the volatility of oil and gas prices; adverse effects our level of indebtedness 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; 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 "non-proven" 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 non-proven drillsites and estimation of non-proven reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

Pro forma for the acquisition of Columbia Natural Resources, LLC and its affiliates, 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 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 September 30, 2005		Three Months Ended September 30, 2004	
	$	$/mcfe	$	$/mcfe
REVENUES:				
Oil and gas sales	720,928	5.99	450,936	4.79
Oil and gas marketing sales	361,915	3.01	178,860	1.90
Total Revenues	1,082,843	9.00	629,796	6.69
OPERATING COSTS:				
Production expenses	80,765	0.67	54,102	0.57
Production taxes	53,102	0.44	30,872	0.33
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	10,536	0.09	8,361	0.09
Stock-based compensation	5,249	0.04	584	0.01
Oil and gas marketing expenses	353,510	2.94	175,426	1.86
Oil and gas depreciation, depletion, and amortization	231,145	1.92	153,586	1.63
Depreciation and amortization of other assets	12,902	0.11	7,700	0.08
Total Operating Costs	747,209	6.21	430,631	4.57
INCOME FROM OPERATIONS	335,634	2.79	199,165	2.12

OTHER INCOME (EXPENSE):				
Interest and other income	2,428	0.02	885	0.01
Interest expense	(58,593)	(0.48)	(48,689)	(0.52)
Loss on repurchases or exchanges of Chesapeake debt	(747)	(0.01)	---	---
Total Other Income (Expense)	(56,912)	(0.47)	(47,804)	(0.51)
Income Before Income Taxes	278,722	2.32	151,361	1.61
Income Tax Expense:				
Current	---	---	---	---
Deferred	101,734	0.85	54,489	0.58
Total Income Tax Expense	101,734	0.85	54,489	0.58
NET INCOME	176,988	1.47	96,872	1.03
Preferred stock dividends	(10,204)	(0.08)	(11,287)	(0.12)
Loss on conversion/ exchange of preferred stock	(17,725)	(0.15)	---	---
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	149,059	1.24	85,585	0.91
EARNINGS PER COMMON SHARE:				
Basic	$0.46		$0.33	
Assuming dilution	$0.43		$0.29	
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in 000's):				
Basic	322,101		257,096	
Assuming dilution	367,639		338,285	

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

	Nine Months Ended September 30, 2005		Nine Months Ended September 30, 2004	
	$	$/mcfe	$	$/mcfe

REVENUES:				
Oil and gas sales	2,032,271	6.01	1,270,394	4.89
Oil and gas marketing sales	882,040	2.61	496,823	1.91
Total Revenues	2,914,311	8.62	1,767,217	6.80
OPERATING COSTS:				
Production expenses	222,660	0.66	148,500	0.57
Production taxes	136,313	0.40	68,559	0.26
General and administrative expenses:				
General and administrative (excluding stock-based compensation)	29,468	0.09	23,947	0.09
Stock-based compensation	10,172	0.03	3,125	0.01
Oil and gas marketing expenses	860,789	2.55	486,205	1.88
Oil and gas depreciation, depletion, and amortization	621,484	1.84	410,237	1.58
Depreciation and amortization of other assets	34,791	0.10	20,155	0.08
Total Operating Costs	1,915,677	5.67	1,160,728	4.47
INCOME FROM OPERATIONS	998,634	2.95	606,489	2.33
OTHER INCOME (EXPENSE):				
Interest and other income	7,790	0.02	3,563	0.01
Interest expense	(155,623)	(0.46)	(124,040)	(0.47)
Loss on repurchases or exchanges of Chesapeake debt	(70,047)	(0.20)	(6,925)	(0.03)
Total Other Income (Expense)	(217,880)	(0.64)	(127,402)	(0.49)
Income Before Income Taxes	780,754	2.31	479,087	1.84
Income Tax Expense:				
Current	---	---	---	---
Deferred	284,977	0.84	172,470	0.66
Total Income Tax Expense	284,977	0.84	172,470	0.66
NET INCOME	495,777	1.47	306,617	1.18
Preferred stock dividends	(25,526)	(0.08)	(30,799)	(0.12)

Loss on conversion/ exchange of preferred stock	(22,468)	(0.07)	---	---
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	447,783	1.32	275,818	1.06

EARNINGS PER COMMON SHARE:

Basic	$1.42	$1.13
Assuming dilution	$1.32	$0.96

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

Basic	314,425	245,087
Assuming dilution	352,210	320,089

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

	September 30, 2005	December 31, 2004
Cash	$127,102	$6,896
Other current assets	1,216,464	560,644
Total Current Assets	1,343,566	567,540
Property and equipment (net)	10,677,424	7,444,384
Other assets	344,639	232,585
Total Assets	$12,365,629	$8,244,509
Current liabilities	$2,042,478	$963,953
Long term debt	4,250,160	3,075,109
Asset retirement obligation	86,022	73,718
Other long term liabilities	121,521	34,973
Deferred tax liability	1,659,128	933,873
Total Liabilities	8,159,309	5,081,626
STOCKHOLDERS' EQUITY	4,206,320	3,162,883
TOTAL LIABILITIES & STOCKHOLDERS' EQUITY	$12,365,629	$8,244,509
COMMON SHARES OUTSTANDING	344,059	311,869

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF COSTS INCURRED FOR NINE MONTHS ENDED SEPTEMBER 30, 2005
($ in 000's, except per unit amounts)
(unaudited)

	Cost	Reserves (in mmcfe)	$/mcfe
Exploration and development costs (A)	$1,317,984	928,708	$1.42
Acquisition of proved properties	1,108,932	720,953	1.54
Subtotal	2,426,916	1,649,661	1.47
Acquisition of unproved properties	767,595	---	---
Divestitures	(1,881)	(491)	---
Leasehold acquisition costs	164,568	---	---
Geological and geophysical costs	44,300	---	---
Adjusted subtotal	3,401,498	1,649,170	2.06
Tax basis step-up	253,194	---	---
Asset retirement obligation and other	20,130	---	---
Total	$3,674,822	1,649,170	$2.23

(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	853,297
Acquisitions	720,953
Divestitures	(491)
Revisions-performance	(18,612)
Revisions-price	94,023
Production	(338,164)
Ending balance, 9/30/05	6,212,757
Reserve replacement	1,649,170
Reserve replacement rate	488%

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

Three Months Ended September 30, Nine Months Ended September 30,

	2005	2004	2005	2004
Oil and Gas Sales ($ in thousands):				
Oil sales	$113,590	$73,921	$290,332	$181,882
Oil derivatives - realized gains (losses)	(10,937)	(20,464)	(28,654)	(41,672)
Oil derivatives - unrealized gains (losses)	(4,009)	(14,436)	(5,951)	(21,925)
Total Oil Sales	$98,644	$39,021	$255,727	$118,285
Gas sales	$833,992	$447,466	$2,005,670	$1,222,783
Gas derivatives - realized gains (losses)	(111,668)	(17,514)	(97,955)	(25,976)
Gas derivatives - unrealized gains (losses)	(100,040)	(18,037)	(131,171)	(44,698)
Total Gas Sales	$622,284	$411,915	$1,776,544	$1,152,109
Total Oil and Gas Sales	$720,928	$450,936	$2,032,271	$1,270,394
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$58.98	$40.31	$51.08	$36.58
Gas ($ per mcf)	$7.67	$5.38	$6.60	$5.32
Gas equivalent ($ per mcfe)	$7.87	$5.53	$6.79	$5.41
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$53.30	$29.15	$46.04	$28.20
Gas ($ per mcf)	$6.64	$5.17	$6.27	$5.21
Gas equivalent ($ per mcfe)	$6.85	$5.13	$6.42	$5.15
Interest Expense ($ in thousands):				
Interest	$58,206	$42,258	$160,209	$118,335
Derivatives - realized (gains) losses	(843)	221	(2,639)	(184)
Derivatives - unrealized (gains) losses	1,230	6,210	(1,947)	5,889
Total Interest Expense	$58,593	$48,689	$155,623	$124,040

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

THREE MONTHS ENDED:	September 30, 2005	September 30, 2004
Cash provided by operating activities	$558,061	$367,649
Cash (used in) investing activities	(1,115,166)	(1,068,791)
Cash provided by financing activities	684,207	673,978

NINE MONTHS ENDED:	September 30, 2005	September 30, 2004
Cash provided by operating activities	$1,638,368	$1,038,206
Cash (used in) investing activities	(3,655,044)	(2,668,241)
Cash provided by financing activities	2,136,882	1,638,527

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF CERTAIN FINANCIAL MEASURES
(in 000's)
(unaudited)

THREE MONTHS ENDED:	September 30, 2005	September 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$558,061	$367,649
Adjustments:		
Changes in assets and liabilities	77,150	(14,252)
OPERATING CASH FLOW*	$635,211	$353,397

*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:	September 30, 2005	September 30, 2004
Net income	$176,988	$96,872
Income tax expense	101,734	54,489
Interest expense	58,593	48,689
Depreciation and amortization of other assets	12,902	7,700
Oil and gas depreciation, depletion and amortization	231,145	153,586
EBITDA**	$581,362	$361,336

**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:	September 30, 2005	September 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$558,061	$367,649
Changes in assets and liabilities	77,150	(14,252)
Interest expense	58,593	48,689
Unrealized gains (losses) on oil and gas derivatives	(104,049)	(32,473)
Other non-cash items	(8,393)	(8,277)
EBITDA	$581,362	$361,336

CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF CERTAIN FINANCIAL MEASURES
(in 000's)
(unaudited)

NINE MONTHS ENDED:	September 30, 2005	September 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$1,638,368	$1,038,206

Adjustments:		
Changes in assets and liabilities	15,589	(43,082)
OPERATING CASH FLOW*	$1,653,957	$995,124

*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.

NINE MONTHS ENDED:	September 30, 2005	September 30, 2004
Net income	$495,777	$306,617
Income tax expense	284,977	172,470
Interest expense	155,623	124,040
Depreciation and amortization of other assets	34,791	20,155
Oil and gas depreciation, depletion and amortization	621,484	410,237
EBITDA**	$1,592,652	$1,033,519

**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:

NINE MONTHS ENDED:	September 30, 2005	September 30, 2004
CASH PROVIDED BY OPERATING ACTIVITIES	$1,638,368	$1,038,206
Changes in assets and liabilities	15,589	(43,082)
Interest expense	155,623	124,040

Unrealized gains (losses) on oil and gas derivatives	(137,122)	(66,623)
Other non-cash items	(79,806)	(19,022)
EBITDA	$1,592,652	$1,033,519

CHESAPEAKE ENERGY CORPORATION

RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON & ADJUSTED EBITDA

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

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net income available to common shareholders	$149,059	$447,783
Adjustments:		
Loss on conversion/exchange of preferred stock	17,725	22,468
Net Income	$166,784	$470,251
Adjustments, net of tax:		
Unrealized (gains) losses on derivatives	66,851	85,836
Loss on repurchases or exchanges of debt	474	44,480
Adjusted net income available to common*	$234,109	$600,567
Adjusted earnings per share assuming dilution**	$0.65	$1.71
EBITDA	$581,362	$1,592,652
Adjustments, before tax:		
Unrealized (gains) losses on oil and gas derivatives	104,049	137,122
Loss on repurchases or exchanges of debt	747	70,047
Adjusted EBITDA*	$686,158	$1,799,821

*Adjusted net income available to common and adjusted earnings per share assuming dilution and adjusted EBITDA 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 and EBITDA because:

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

b. Adjusted net income available to common and adjusted EBITDA are more comparable to earnings and EBITDA 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 and nine months ended September 30, 2005, accounting rules prohibit the company from assuming the conversion of the 4.125% preferred stock, 4.50% preferred stock and 5.00% (Series 2003) preferred stock for common shares prior to conversion or exchange for either period since the effect would have been anti-dilutive. In determining adjusted earnings per share, we have reflected these shares as though they were converted at the beginning of the period which increases the fully diluted share count to 376.6 million and 365.1 million for the three and nine months ended September 30, 2005, respectively.

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF OCTOBER 31, 2005

Quarter Ending December 31, 2005; Year Ending December 31, 2005; 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 October 31, 2005, we are using the following key assumptions in our projections for the fourth quarter of 2005, the full-year 2005, the full-year 2006 and the full-year 2007.

The primary changes from our October 3, 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 October 3, 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 updated certain of our costs to reflect changing market conditions.
4) We have provided our initial guidance for the full-year 2007.
5) We have not reflected any of CNR's derivative positions. We will record 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.

	Quarter Ending 12/31/2005	Year Ending 12/31/2005	Year Ending 12/31/2006	Year Ending 12/31/2007
Estimated Production:				
Oil - Mbo	1,950	7,650	7,700	7,750
Gas - Bcf	112 - 114	416 - 419	512 - 522	553 - 563

Gas Equivalent - Bcfe	124 - 126	462 - 465	558 - 568	599 - 609
Daily gas equivalent midpoint -in Mmcfe	1,359	1,270	1,543	1,655
NYMEX Prices (for calculation of realized hedging effects only):				
Oil - $/Bo	$60.00	$56.59	$50.00	$50.00
Gas - $/Mcf	$10.64	$8.05	$7.00	$7.00
Estimated Differentials to NYMEX Prices:				
Oil - $/Bo	6-8%	6-8%	6-8%	6-8%
Gas - $/Mcf	10-15%	8-12%	8-12%	8-12%
Estimated Realized Hedging Effects (based on expected NYMEX prices above):				
Oil - $/Bo	-$2.78	-$4.30	$4.94	$0.35
Gas - $/Mcf	-$1.58	-$0.41	$0.80	$0.26
Operating Costs per Mcfe of Projected Production:				
Production expense	$0.70 - 0.74	$0.68 - 0.72	$0.77 - 0.82	$0.80 - 0.85
Production taxes (generally 6.5% of O&G revenues) (A)	$0.60 - 0.64	$0.45 - 0.50	$0.40 - 0.45	$0.40 - 0.45
General and administrative	$0.10 - 0.12	$0.10 - 0.12	$0.11 - 0.13	$0.11 - 0.13
Stock-based compensation (non-cash)	$0.03 - 0.05	$0.03 - 0.05	$0.08 - 0.10	$0.10 - 0.12
DD&A - oil and gas	$2.05 - 2.10	$1.85 - 1.95	$2.15 - 2.20	$2.25 - 2.30
Depreciation of other assets	$0.10 - 0.12	$0.09 - 0.11	$0.10 - 0.12	$0.11 - 0.13
Interest expense (B)	$0.48 - 0.52	$0.45 - 0.49	$0.48 - 0.53	$0.50 - 0.55
Other Income and Expense per Mcfe:				
Marketing and other income	$0.02 - 0.04	$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%	36.5%
Equivalent Shares Outstanding:				
Basic	345 mm	322 mm	360 mm	364 mm
Diluted	406 mm	375 mm	424 mm	429 mm
Capital Expenditures:				

Drilling, leasehold and seismic	$575 - 625 mm	$2,000 - 2,200 mm	$2,700 - 2,900 mm	$3,100 - 3,300 mm

(A) Severance tax per mcfe is based on NYMEX prices of $60.00 per bo and natural gas prices ranging from $9.00 to $11.30 per mcf during Q4 2005, $60.00 per bo and natural gas prices ranging from $7.25 to $12.50 per mcf during calendar 2005, $50.00 per bo and $6.75 to $7.60 per mcf during calendar 2006 and 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.

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	NYMEX Price Including Open & Locked Positions	Assuming Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Gas Production
2005:						
Q4 2005(A)	82.2	$8.27	-$0.13	$8.14	113.0	73%
2006:						
Q1	67.5	$10.01	-$0.12	$9.89	122.0	55%
Q2	51.9	$8.11	-$0.10	$8.01	127.0	41%
Q3	52.4	$8.10	-$0.10	$8.00	132.0	40%
Q4	45.7	$8.31	-$0.10	$8.21	136.0	34%
Total 2006(A)	217.5	$8.74	-$0.11	$8.63	517.0	42%
Total 2007	38.1	$9.47	-$0.31	$9.16	558.0	7%
Total 2008	11.0	$8.37	---	$8.37	585.0	2%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 20.1 bcf in 2005 and $3.75 to $5.50 covering 43.0 bcf in 2006.

Note: Not shown above are collars covering 1.4 bcf of production in 2005 at a weighted average floor and ceiling of $3.49 and $5.27 and 0.2 bcf of production in 2006 at a weighted average floor and ceiling of $6.00 and $9.70 and call options covering 1.8 bcf of production in 2005 at a weighted average price of $5.86, 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
4th Quarter 2005	49.4	$0.27	113	44%
2006	130.1	0.32	517	25%
2007	126.5	0.28	558	23%
2008	118.6	0.27	585	20%
2009	86.6	0.29	615	14%
Totals	511.2	$0.29	2,388	21%

* weighted average

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

	Open Swaps in mbo's	Avg. NYMEX Strike Price	Assuming Oil Production in mbo's of:	% Hedged Open Swap Positions as % of Total Estimated Production
2005:				
Q4 2005(A)	1,073.5	$54.97	1,950.0	55%
2006:				
Q1	1,035.0	$59.71	1,900.0	54%
Q2	1,016.5	$59.60	1,920.0	53%
Q3	966.0	$59.83	1,940.0	50%
Q4	920.0	$59.45	1,940.0	47%
Total 2006(A)	3,937.5	$59.65	7,700.0	51%
Total 2007	635.0	$54.29	7,750.0	8%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $26.00 to $42.00 covering 276 mbo in 2005 and $40.00 to $42.00 covering 501.5 mbo in 2006.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF OCTOBER 3, 2005
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF OCTOBER 31, 2005

Quarter Ending September 30, 2005; Quarter Ending December 31, 2005; Year Ending December 31, 2005; Year Ending December 31, 2006.

We have adopted a policy of periodically providing investors with guidance on certain factors that affect our future financial performance. As of October 3, 2005, we are using the following key assumptions in our projections for the third quarter of 2005, the fourth quarter of 2005, the full-year 2005 and the full-year 2006.

The primary changes from our September 7, 2005 Outlook are in italicized bold in the table and are explained as follows:

1) We have shown the operational and financial effects of the pending acquisition and anticipated financing as described in our press release dated October 3, 2005. We have assumed that the CNR acquisition will close no later than December 15, 2005.

2) We have updated the projected effect of changes in our hedging positions since our September 7, 2005 Outlook.
3) We have updated our expectations for future NYMEX oil and gas prices based on current market conditions in order to illustrate hedging effects only.
4) We have updated certain of our costs to reflect changing market conditions and the impact of the CNR acquisition.
5) We have increased our estimated basic common share count to reflect the common stock issued in connection with the exchanges of a portion of our preferred stock during September 2005.
6) We have provided guidance for the fourth quarter of 2005.

	Quarter Ending 9/30/2005	Quarter Ending 12/31/2005	Year Ending 12/31/2005	Year Ending 12/31/2006
Estimated Production:				
Oil - Mbo	1,950	1,950	7,650	7,700
Gas - Bcf	107 - 109	112 - 114	416 - 419	512 - 522
Gas Equivalent - Bcfe	118.5 - 120.5	124 - 126	462 - 465	558 - 568
Daily gas equivalent midpoint - in Mmcfe	1,300	1,359	1,270	1,543
NYMEX Prices (for calculation of realized hedging effects only):				
Oil - $/Bo	$61.34	$60.00	$56.09	$50.00
Gas - $/Mcf	$8.53	$9.00	$7.64	$7.00
Estimated Differentials to NYMEX Prices:				
Oil - $/Bo	-$4.50	-$4.50	-$4.50	-$4.50
Gas - $/Mcf	-$0.80	-$1.50	-$1.00	-$1.00
Estimated Realized Hedging Effects (based on expected NYMEX prices above):				
Oil - $/Bo	-$4.48	-$2.78	-$4.09	$4.94
Gas - $/Mcf	-$1.21	-$0.33	-$0.21	$0.66
Operating Costs per Mcfe of Projected Production:				
Production expense	$0.68 - 0.72	$0.70 - 0.74	$0.68 - 0.72	$0.77 - 0.82
Production taxes (generally 7% of O&G revenues) (A)	$0.51 - 0.56	$0.56 - 0.60	$0.45 - 0.50	$0.45 - 0.50
General and administrative	$0.10 - 0.12	$0.10 - 0.12	$0.10 - 0.12	$0.11 - 0.13

Stock-based compensation (non-cash)	$0.03 - 0.05	$0.03 - 0.05	$0.03 - 0.05	$0.04 - 0.06
DD&A - oil and gas	$1.85 - 1.95	$2.05 - 2.10	$1.85 - 1.95	$2.15 - 2.20
Depreciation of other assets	$0.09 - 0.11	$0.10 - 0.12	$0.09 - 0.11	$0.10 - 0.12
Interest expense (B)	$0.48 - 0.52	$0.48 - 0.52	$0.45 - 0.49	$0.48 - 0.53
Other Income and Expense per Mcfe:				
Marketing and other income	$0.02 - 0.04	$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%	36.5%
Equivalent Shares Outstanding:				
Basic	322 mm	342 mm	321 mm	355 mm
Diluted	376 mm	399 mm	373 mm	418 mm
Capital Expenditures:				
Drilling, leasehold and seismic	$485 - $535 mm	$575 - $625 mm	$2,000 - $2,200 mm	$2,500 - $2,700 mm

(A) Severance tax per mcfe is based on NYMEX prices of $60.00 per bo and natural gas prices ranging from $8.70 to $10.00 per mcf during Q3 2005, $60.00 per bo and natural gas prices ranging from $9.25 to $10.00 per mcf during Q4 2005, $60.00 per bo and natural gas prices ranging from $8.25 to $10.00 per mcf during calendar 2005 and $50.00 per bo and $7.15 to $7.90 per mcf during calendar 2006.

(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.

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	NYMEX Price Including Open & Locked Positions	Assuming Gas Production in Bcf's of:	% Hedged Open Swap Positions as a % of Estimated Total Gas Production
2005:						
Q3	72.9	$6.64	-$0.15	$6.49	108.0	68%
Q4	79.5	$8.06	-$0.14	$7.92	113.0	70%
Remaining 2005(A)	152.4	$7.38	-$0.14	$7.24	221.0	69%
2006:						
Q1	58.5	$9.38	-$0.15	$9.23	122.0	48%
Q2	44.6	$7.73	-$0.13	$7.60	127.0	35%
Q3	45.1	$7.73	-$0.12	$7.61	132.0	34%
Q4	38.4	$7.82	-$0.12	$7.70	136.0	28%
Total 2006 (A)	186.6	$8.27	-$0.13	$8.14	517.0	36%
Total 2007	14.4	$9.09	-$0.81	$8.28	555.0	3%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $3.75 to $5.50 covering 42.6 bcf in 2005 and $3.75 to $5.50 covering 43.0 bcf in 2006.

Note: Not shown above are collars covering 3.0 bcf of production in 2005 at a weighted average floor and ceiling of $3.59 and $5.37 and 0.2 bcf of production in 2006 at a weighted average floor and ceiling of $6.00 and $9.70 and call options covering 3.7 bcf of production in 2005 at a weighted average price of $5.79, 7.3 bcf of production in 2006 at a weighted average price of $12.50 and 7.3 bcf of production in 2007 at a weighted 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
3rd & 4th Quarter 2005	96.3	$0.27	221	44%
2006	130.1	0.32	517	25%
2007	126.5	0.28	555	23%
2008	118.6	0.27	580	20%
2009	86.6	0.29	605	14%
Totals	558.1	$0.29	2,478	23%

* weighted average

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

	Open Swaps in mbo's	Avg. NYMEX Strike Price	Assuming Oil Production in mbo's of:	% Hedged Open Swap Positions as % of Total Estimated Production
2005:				
Q3	903.5	$51.66	1,950	46%
Q4	1,073.5	$54.97	1,950	55%
Remaining 2005 (A)	1,977.0	$53.46	3,900	51%
2006:				
Q1	1,035.0	$59.64	1,900.0	54%
Q2	1,016.5	$59.57	1,920.0	53%
Q3	966.0	$59.85	1,940.0	50%
Q4	920.0	$59.55	1,940.0	47%
Total 2006 (A)	3,937.5	$59.65	7,700.0	51%
Total 2007	635.0	$54.29	7,750.0	8%

(A) Certain hedging arrangements include swaps with knockout prices ranging from $26.00 to $42.00 covering 552 mbo in 2005 and $40.00 to $42.00 covering 501.5 mbo in 2006.

SOURCE: Chesapeake Energy Corporation

CONTACT: investors, Jeffrey L. Mobley, CFA, Vice President - Investor Relations and Research, +1-405-767-4763, or jmobley@chkenergy.com , or media, Thomas S. Price, Jr., Senior Vice President - Corporate Development, +1-405-879-9257, or tprice@chkenergy.com , both of Chesapeake Energy Corporation

Web site: http://www.chkenergy.com/
