NEWS RELEASE

Chesapeake Energy Corporation Announces Agreement to Acquire Appalachian Basin Natural Gas Producer Columbia Natural Resources, LLC for $2.2 Billion in Cash

Company Will Acquire Production of 125 Mmcfe Per Day and Internally Estimated Reserves of 2.5 Tcfe, Consisting of 1.1 Tcfe of Proved Reserves and 1.4 Tcfe of Probable and Possible Reserves

Columbia Is the Fourth Largest Natural Gas Producer in the Appalachian Basin and Largest Leaseholder, Owning 4.1 Million Net Acres on Which Chesapeake Has Identified 9,435 Drilling Locations

Pro Forma for the Transaction, Chesapeake's Projected December 2005 Production Rate Increases to 1,460 Mmcfe Per Day, Proved Reserves Reach 7.1 Tcfe, Proved and Unproved Reserves Reach 13.5 Tcfe and Leasehold Inventory Doubles to 8.2 Million Net Acres

PRNewswire-FirstCall
OKLAHOMA CITY

Chesapeake Energy Corporation today announced that it has entered into an agreement to acquire Columbia Natural Resources, LLC and certain affiliated entities (CNR) from Triana Energy Holdings LLC (Triana) for $2.2 billion in cash, the assumption of an estimated $75 million working capital deficit and liabilities related to CNR's prepaid sales agreement and hedging positions.

Through this transaction, Chesapeake anticipates acquiring an internally estimated 2.5 trillion cubic feet of natural gas equivalent (tcfe) of proved, probable and possible (3P) reserves, comprised of 1.1 tcfe of proved reserves and 1.4 tcfe of probable and possible reserves. The seller's independent third party engineering report calculated CNR's 3P reserves to be 3.9 tcfe, or 56% more 3P reserves than Chesapeake will initially recognize. CNR's current daily net production is approximately 125 million cubic feet of natural gas equivalent (mmcfe), indicating a proved reserves-to-production index of 23.0 years and a proved developed reserves-to-production index of 16.0 years. The properties are principally located in West Virginia, Kentucky, Ohio, Pennsylvania and New York.

After the preliminary allocation of $175 million of the $2.2 billion purchase price (which excludes negative working capital and liabilities associated with the assumed prepaid sales agreement and hedges) to CNR's extensive mid-stream natural gas assets being acquired (including over 6,500 miles of natural gas gathering lines) and $500 million to the unevaluated portion of the 4.1 million net leasehold acres being acquired (3.5 million net acres in the U.S. and 0.6 million net acres in Canada), Chesapeake's acquisition cost for the 1.1 tcfe of internally estimated proved reserves will be approximately $1.45 per thousand cubic feet of natural gas equivalent (mcfe). Based on the company's projected development plan, which includes approximately $4.1

billion of anticipated future drilling and development costs, Chesapeake estimates that its all-in cost of acquiring and developing the 2.5 tcfe of 3P reserves will be approximately $2.48 per mcfe, exclusive of the negative working capital and prepaid sales and hedging liabilities to be assumed.

CNR's proved reserves are long-lived, have low production decline rates (the proved developed producing base is projected to decline at less than 10% per year), are 99% natural gas, have an average BTU content of 1,140 and are 70% proved developed. In addition, gas sold from the properties generally receives a $0.50 per mmbtu premium to NYMEX gas prices, compared to basis differential discounts that currently range up to $4.00 per mmbtu in various southwestern and western U.S. natural gas supply basins. Adjusting further for the favorable BTU content, CNR's natural gas today receives wellhead prices of up to $5.00 per mcfe more than typical southwestern and western U.S. natural gas production.

On the acquired properties, Chesapeake has identified 1,316 proved undeveloped (PUD) locations, 6,286 probable locations and 1,833 possible locations for a total of 9,435 undrilled locations, or an estimated drilling inventory of more than 15 years. By comparison, the seller's independent reservoir engineers identified 1,611 PUD locations (22% more than Chesapeake will initially recognize) and over 14,000 probable and possible locations (72% more than Chesapeake will initially recognize).

As of June 30, 2005 and pro forma for this acquisition, Chesapeake will own an internally estimated 13.5 tcfe of proved and unproved oil and natural gas reserves, comprised of 7.1 tcfe of proved reserves (which will be 92% natural gas and 100% onshore) and 6.4 tcfe of unproved reserves. The company intends to spend at least $200 million per year for the foreseeable future in further developing the acquired properties and is budgeting production growth from the acquired assets of 5-10% per year.

Chesapeake has begun the process of hedging the production it will acquire from CNR. The company intends to hedge at least 50% of CNR's estimated base production through December 2008. The prices received from such hedging should significantly exceed the pricing assumptions used by Chesapeake to value the properties.

As part of the transaction, the company will assume CNR's prepaid sales agreement and its hedging arrangements. Chesapeake expects to record any potential mark-to-market loss on those obligations as a balance sheet liability when the transaction closes. The amount of the mark-to-market loss will be dependent on gas prices on the day of closing. For example, using a flat $7.00 NYMEX gas strip through December 2009, the prepaid sales and hedging liabilities would be approximately $325 million. Using gas prices as of September 30, 2005, the prepaid sales and hedging liabilities would be approximately $775 million.

Chesapeake will soon file its Hart-Scott-Rodino (HSR) pre-merger notification form with the Federal Trade Commission. Satisfaction of the HSR requirements should occur within 30 days after filing. Accordingly, the company anticipates closing the transaction no later than December 15, 2005. The company intends to finance the acquisition from cash on hand and by issuing a balanced combination of senior notes and equity securities. As a result of this acquisition and the contemplated financings, the company has attached its updated Outlook as Exhibit "A" to this release. The company's previous Outlook, dated September 7, 2005, is attached as Exhibit "B" for comparative purposes.

Triana was formed in 2001 by management and executives of Metalmark Capital LLC as a Morgan Stanley Capital Partners portfolio company. Triana was advised in this transaction by Morgan Stanley & Co. Incorporated and Credit Suisse First Boston LLC.

Management Comment

Aubrey K. McClendon, Chesapeake's Chief Executive Officer, commented, "We are excited to announce the acquisition of CNR for several reasons. First, we will acquire very significant land and gas resource inventories to complement our already very large land and gas resource inventories. CNR's additional 4.1 million net acres and 2.5 tcfe of 3P reserves will increase Chesapeake's leasehold and gas resource inventories to 8.2 million net acres and 13.5 tcfe, respectively. According to rankings published last week by the Oil & Gas Journal, Chesapeake's pro forma 6.5 tcf of proved gas reserves will be the third largest in the U.S., trailing only those of ExxonMobil and ConocoPhillips. We believe this transaction will solidify Chesapeake's position as the premier gas resource company in the industry.

"Secondly, we are very enthusiastic about moving into the large, prolific and generally underexplored and unconsolidated Appalachian Basin. The basin covers over 185,000 square miles (almost three times the size of Oklahoma) across seven states and has produced more than 46 tcf of gas from over 400,000 wells. In 2003, the National Petroleum Council estimated the basin still contained another 9 tcf of proved gas reserves and an additional 68 tcf of unproved gas reserves. In addition, much of the basin remains underexplored. Less than 1% of the 400,000 wells drilled to date have penetrated below 7,500 feet, leaving substantial deeper exploration opportunities available for Chesapeake to pursue. We believe deep gas exploration is one of our most important competitive strengths.

"Third, we are also attracted to the value proposition of producing natural gas at a premium price to NYMEX, rather than for the steep discount to NYMEX that most other U.S. natural gas sells for today. Some basis differentials now exceed $4.00 per mmbtu, creating a very pronounced value advantage for Appalachian Basin gas production. Including an approximate 14% value upgrade for the rich BTU content of the gas, we believe prices realized on CNR's gas production today would be more than $5.00 per mcfe higher than prices received in most southwestern and western U.S. gas basins.

"In addition, we are eager to begin working in a large U.S. natural gas basin that shares many similarities to our stronghold in the Mid-Continent, where 59% of our pro forma production is located. As in the Mid-Continent area seven years ago, Appalachian Basin asset ownership is very fragmented and gas production has typically been developed by a large number of very small private companies, a few mid-sized public independents and several large pipeline and utility companies. We believe that Chesapeake's significant presence in the Barnett, Woodford, Caney and Fayetteville shale plays, our expertise in tight sand and horizontal coalbed methane drilling and our commitment to deep natural gas exploration will enable us to achieve success in Appalachia.

"Although the Appalachian Basin will be a new area for Chesapeake, we have been in conversations with CNR's management for over three years and have been educating ourselves about the basin during that time. We believe the geological age of the reservoirs, the types of geological plays and the gas- prospectivity of the basin are an excellent fit with Chesapeake's existing competitive advantages. We look forward to decades of success in the Appalachian Basin.

"And finally, it has become abundantly clear in the past month that the U.S. needs significant additional supplies of clean-burning, domestically- produced onshore natural gas. During the past five years, Chesapeake has been the most active driller in the U.S. and has discovered and developed major new supplies of natural gas that U.S. consumers increasingly need. In 2006, the company plans to utilize an average of 85-90 drilling rigs to continue exploring for new supplies of natural gas. While others in the industry are increasingly focused on international projects, we remain committed to supplying consumers with as much natural gas as Chesapeake can find onshore in the U.S."

Henry Harmon, President and CEO of Triana said, "This transaction underscores the success of combining Triana management's vision and the longstanding partnership with executives of Metalmark Capital to create one of the largest gas exploration and production companies in the Appalachian Basin."

Conference Call Information

A conference call has been scheduled for Tuesday morning, October 4, 2005 at 9:00 a.m. EDT to discuss this press release. The telephone number to access the conference call is 913.981.5592. For those unable to participate in the conference call, a replay will be available from 12:00 noon EDT, October 4, 2005 through midnight EDT on October 18, 2005. The number to access the conference call replay is 719.457.0820 and the passcode is 5537544. 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 our expected acquisition of Columbia Natural Resources, LLC and related financings, 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 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. In addition, the CNR acquisition is subject to conditions which must be satisfied before closing. 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 "un-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 unproven drillsites and estimation of unproven reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers.

The announcement of proposed financings through the issuance of equity and senior notes in this press release shall not constitute an offer to sell or a solicitation of an offer to buy the securities. The terms of any such offerings have not been decided. The securities may not be registered under the Securities Act of 1933 or any state securities laws and, if not registered, may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act and state laws.

Pro forma for the CNR acquisition, 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, most recently, the Appalachian Basin regions of the United States. The company's Internet address is http://www.chkenergy.com/ .

SCHEDULE "A"

CHESAPEAKE'S OUTLOOK AS OF OCTOBER 3, 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:

% Hedged

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Avg. NYMEX Gain (Loss) from Locked Swaps	Price Including Open & Locked Positions	Open Swap Positions as a Assuming Gas Production in Bcf's of:	% 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	% Hedged Assuming Oil Production in mbo's of:	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.

SCHEDULE "B"

CHESAPEAKE'S PREVIOUS OUTLOOK AS OF SEPTEMBER 7, 2005
(PROVIDED FOR REFERENCE ONLY)

NOW SUPERSEDED BY OUTLOOK AS OF OCTOBER 3, 2005

Quarter Ending September 30, 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 September 7, 2005, we are using the following key assumptions in our projections for the third quarter of 2005, the full-year 2005 and the full- year 2006.

The primary changes from our August 4, 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 August 4, 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 included the effects of refinancing amounts outstanding under our revolving credit facility with the issuance of $600 million of our 6.5% Senior Notes which occurred in August 2005.
5) We have included the projected effects of refinancing amounts outstanding on our revolving credit facility with the issuance of 8 million shares of common stock and $250 million of preferred stock.

	Quarter Ending September 30, 2005	Year Ending December 31, 2005	Year Ending December 31, 2006
Estimated Production:			
Oil - Mbo	1,950	7,650	7,700
Gas - Bcf	107-109	411-417	465-475
Gas Equivalent - Bcfe	118.5-120.5	457-463	511-521
Daily gas equivalent midpoint - in Mmcfe	1,300	1,260	1,414
NYMEX Prices (for calculation of realized hedging effects only):			
Oil - $/Bo	$61.34	$56.09	$50.00

Gas - $/Mcf	$8.53	$7.64	$7.00
Estimated Differentials to NYMEX Prices:			
Oil - $/Bo	-$4.50	-$4.46	-$4.50
Gas - $/Mcf	-$0.80	-$0.75	-$0.80
Estimated Realized Hedging Effects (based on expected NYMEX prices above):			
Oil - $/Bo	-$4.48	-$4.13	$4.94
Gas - $/Mcf	-$1.21	-$0.32	$0.48
Operating Costs per Mcfe of Projected Production:			
Production expense	$0.68-0.72	$0.68-0.72	$0.72-0.77
Production taxes (generally 7% of O&G revenues) (A)	$0.51-0.56	$0.45-0.50	$0.45-0.50
General and administrative	$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	$0.04-0.06
DD&A - oil and gas	$1.85-1.95	$1.80-1.90	$2.00-2.10
Depreciation of other assets	$0.09-0.11	$0.09-0.11	$0.10-0.12
Interest expense (B)	$0.48-0.52	$0.45-0.49	$0.45-0.50
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	322 mm	318 mm	332 mm
Diluted	376 mm	370 mm	389 mm
Capital Expenditures:			
Drilling, leasehold and seismic	$485-$535 mm	$1,900-$2,100 mm	$2,100-$2,300 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, $55.00 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:

% Hedged

	Open Swaps in Bcf's	Avg. NYMEX Strike Price Of Open Swaps	Avg. NYMEX 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
2005:						
Q3	72.9	$6.64	-$0.15	$6.49	108.0	68%
Q4	78.0	$7.94	-$0.13	$7.81	110.8	70%
Remaining 2005 (A)	150.9	$7.31	-$0.14	$7.17	218.8	69%
2006:						
Q1	56.3	$9.19	-$0.15	$9.04	110.0	51%
Q2	41.4	$7.51	-$0.13	$7.38	115.0	36%
Q3	41.9	$7.52	-$0.13	$7.39	120.0	35%
Q4	35.4	$7.57	-$0.13	$7.44	125.0	28%
Total 2006 (A)	175.0	$8.07	-$0.14	$7.93	470.0	37%
Total 2007	11.7	$8.55	-$0.99	$7.56	505.0	2%

(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 35.7 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.

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
Remaining 2005	96.3	$ 0.27	218.8	44%
2006	130.1	0.32	470.0	28%
2007	126.5	0.28	505.0	25%
2008	118.6	0.27	530.0	22%
2009	86.6	0.29	555.0	16%
Totals	558.1	$ 0.29	2,278.8	24%

* 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
2005:				
Q3	903.5	$51.66	1,950	46%
Q4	1,073.5	$54.97	1,942	55%
Remaining 2005 (A)	1,977.0	$53.46	3,892	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

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http://investors.chk.com/2005-10-03-Chesapeake-Energy-Corporation-Announces-Agreement-to-Acquire-Appalachian-Basin-Natural-Gas-Producer-Columbia-Natural-Resources-LLC-for-2-2-Billion-in-Cash