NEWS RELEASE

CHESAPEAKE ENERGY

Chesapeake Energy Corporation Reports Financial and Operational Results for the 2011 First Quarter

Company Reports 2011 First Quarter Net Loss to Common Stockholders of $205 Million, or $0.32 per Fully Diluted Common Share, on Revenue of $1.6 Billion; Company Reports Adjusted Net Income Available to Common Stockholders of $518 Million, or $0.75 per Fully Diluted Common Share, Adjusted Ebitda of $1.3 Billion and Operating Cash Flow of $1.4 Billion 2011 First Quarter Production Averages 3.107 Bcfe per Day, an Increase of 20% over 2010 First Quarter Production and 6% over 2010 Fourth Quarter Production; 2011 First Quarter Liquids Production Increases 56% Compared to the 2010 First Quarter and 9% Compared to the 2010 Fourth Quarter; 2011 First Quarter Liquids Production Accounts for 13% of Total Production and 23% of Realized Natural Gas and Oil Revenue Proved Reserves Total 15.6 Tcfe Following the Sale of 2.5 Tcfe of Proved Reserves; Company Adds New Net Proved Reserves of 1.3 Tcfe Through the Drillbit at a Drilling and Completion Cost of $1.25 per Mcfe Company's Leasehold Reaches 1.2 Million Net Acres in the Utica Shale Play in the Appalachian Basin and 1.1 Million Net Acres in the Mississippian Carbonate Play in Northern Oklahoma and Southern Kansas; JV Process is Expected to Commence for Each Play in the 2011 Second Half Company Highlights its Oilfield Service Vertical Integration Strategy and Estimates that its Oilfield Service Assets Are Worth Approximately $7.0 Billion

OKLAHOMA CITY, OKLAHOMA, MAY 2, 2011 – Chesapeake Energy Corporation (NYSE:CHK) today announced its 2011 first quarter financial and operational results. For the quarter, Chesapeake reported a net loss to common stockholders of $205 million ($0.32 per fully diluted common share), operating cash flow of $1.404 billion (defined as cash flow from operating activities before changes in assets and liabilities) and ebitda of $167 million (defined as net income before income taxes, interest expense, and depreciation, depletion and amortization) on revenue of $1.612 billion and production of 280 billion cubic feet of natural gas equivalent (bcfe).

The company's 2011 first quarter results include various items that are typically not included in published estimates of the company's financial results by certain securities analysts. Excluding the items detailed below, for the 2011 first quarter, Chesapeake reported adjusted net income to common stockholders of $518 million ($0.75 per fully diluted common share) and adjusted ebitda of $1.346 billion. The excluded items and their effects on the 2011 first quarter reported results are detailed as follows:

- a net unrealized after-tax mark-to-market loss of $725 million resulting from the company's natural gas, oil and interest rate hedging programs;
- a net after-tax gain of $3 million related to the sale of certain of the company's fixed assets; and
- an after-tax loss of $1 million related to the redemption of certain of the company's senior notes.

The various items described above do not materially 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 18 – 20 of this release.

Key Operational and Financial Statistics Summarized

The table below summarizes Chesapeake's key results during the 2011 first quarter and compares them to results during the 2010 fourth quarter and the 2010 first quarter.

2011 First Quarter Average Daily Production of 3.107 Bcfe per Day Increases 20% over 2010 First Quarter Production and 6% over 2010 Fourth Quarter Production; 2011 First Quarter Liquids Production Increases 56% Compared to the 2010 First Quarter and 9% Compared to the 2010 Fourth Quarter; 2011 First Quarter Liquids Production Accounts for 13% of Total Production and 23% of Realized Natural Gas and Oil Revenue

Chesapeake's daily production for the 2011 first quarter averaged 3.107 bcfe, an increase of 521 million cubic feet of natural gas equivalent (mmcfe), or 20%, over the 2.586 bcfe produced per day in the 2010 first quarter and an increase of 187 mmcfe, or 6%, over the 2.920 bcfe produced per day in the 2010 fourth quarter.

Chesapeake's average daily production of 3.107 bcfe for the 2011 first quarter consisted of 2.704 billion cubic feet of natural gas (bcf) and 67,200 barrels (bbls) of oil and natural gas liquids (NGLs). The company's 2011 first quarter production of 279.6 bcfe was comprised of 243.3 bcf (87% on a natural gas equivalent basis) and 6.0 million bbls of oil and NGLs (liquids) (13% on a natural gas equivalent basis). The company's year-over-year growth rate of natural gas production was 16% and its year-over-year growth rate of liquids production was 56%. Sequential quarterly production growth was 3% for natural gas and 9% for liquids. The company's percentage of revenue from liquids in the 2011 first quarter was 23% of realized natural gas and oil revenue compared to 17% in the 2010 first quarter. In affirmation of its 25/25 Plan discussed on page 8 of this release, Chesapeake anticipates delivering production growth of 25% for the two-year period ending December 31, 2012, net of property divestitures.

Chesapeake's Proved Natural Gas and Oil Reserves Decrease by 1.5 Tcfe, or 9%, in the 2011 First Quarter to 15.6 Tcfe Following the Sale of 2.5 Tcfe of Proved Reserves; Company Adds New Net Proved Reserves of 1.3 Tcfe through the Drillbit at a Drilling and Completion Cost of $1.25 per Mcfe

During the 2011 first quarter, Chesapeake continued the industry's most active drilling program, drilling 375 gross operated wells (234 net wells with an average working interest of 62%) and participating in another 430 gross non-operated wells (60 net wells with an average working interest of 14%). The company's drilling success rate was 98% for company-operated wells and 99% for non-operated wells. During the 2011 first quarter, Chesapeake's drilling and completion costs of $1.664 billion included the benefit of approximately $527 million of drilling and completion carries from its joint venture partners.

The following table compares Chesapeake's March 31, 2011 proved reserves, the decrease versus its year-end 2010 proved reserves, estimated future net cash flows from proved reserves (discounted at an annual rate of 10% before income taxes (PV-10)), and proved developed percentage based on the trailing 12-month average price required by the reserve reporting rules of the Securities and Exchange Commission

(SEC) and the 10-year average NYMEX strip prices at March 31, 2011.

A complete reconciliation of proved reserves based on these two alternative pricing methods, along with total costs, is presented on pages 14 and 15 of this release

At the end of the 2011 first quarter, Chesapeake closed the sale of its upstream and midstream assets in the Fayetteville Shale to BHP Billiton Petroleum, a wholly owned subsidiary of BHP Billiton Limited (NYSE:BHP; ASX:BHP), for net proceeds of approximately $4.65 billion in cash. The sale included approximately 2.4 trillion cubic feet of natural gas equivalent (tcfe) of proved reserves, which resulted in the decline in proved reserves for the 2011 first quarter. Excluding this sale, Chesapeake's proved reserves would have been 18.0 tcfe, an increase of 0.9 tcfe, or 5%, over the 2010 year-end proved reserves of 17.1 tcfe.

In addition to the PV-10 value of its proved reserves, the company also has substantial value in its undeveloped leasehold, particularly its unconventional natural gas shale plays in the Marcellus, Haynesville, Bossier, Pearsall and Barnett and its unconventional liquids-rich plays in the Granite Wash, Cleveland, Tonkawa and Mississippian plays of the Anadarko Basin; the Eagle Ford Shale in South Texas; the Niobrara Shale in the Powder River and DJ basins; the Bone Spring, Avalon, Wolfcamp and Wolfberry plays of the Permian Basin; the Three Forks/ Bakken play in the Williston Basin; and the Utica Shale in the Appalachian Basin.

Additionally, the net book value of the company's other assets (including gathering systems, compressors, land and buildings, investments and other non-current assets) was $6.1 billion as of March 31, 2011 and December 31, 2010.

Chesapeake's Leasehold and 3-D Seismic Inventories Total 14.3 Million Net Acres and 28.3 Million Acres, Respectively; Risked Unproved Resources in the Company's Inventory Total 107 Tcfe; Company's Leasehold Reaches 1.2 Million Net Acres in the Utica Shale Play in the Appalachian Basin and 1.1 Million Net Acres in the Mississippian Carbonate Play in Northern Oklahoma and Southern Kansas; Company Expects to Commence JV Process for Each Play in the 2011 Second Half

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (14.3 million net acres) and 3-D seismic (28.3 million acres) in the U.S. The company has accumulated the largest inventory of U.S. natural gas shale play leasehold (2.5 million net acres) and now owns a leading position in 12 of the Top 13 unconventional liquids-rich plays in the U.S. – the Granite Wash, Cleveland, Tonkawa and Mississippian plays of the Anadarko Basin; the Avalon, Bone Spring, Wolfcamp and Wolfberry plays of the Permian Basin; the Eagle Ford Shale of South Texas; the Niobrara Shale in the Powder River and DJ basins; the Three Forks/Bakken in the Williston Basin; and the Utica Shale of the Appalachian Basin.

On its total leasehold inventory, Chesapeake has identified an estimated 16.5 tcfe of proved reserves (using volume estimates based on the 10-year average NYMEX strip prices at March 31, 2011), 107 tcfe of risked unproved resources and 289 tcfe of unrisked unproved resources. The company is currently using 156 operated drilling rigs to further develop its inventory of approximately 39,000 net drillsites. Of Chesapeake's 156 operated rigs, 88 are drilling wells primarily focused on unconventional natural gas plays (including 53 operated rigs utilizing drilling carries) and 65 are drilling wells primarily focused on unconventional liquids-rich plays (including 23 operated rigs utilizing drilling carries). In addition, 151 of the company's 156 operated rigs are drilling horizontal wells.

In recognition of the value gap between oil and natural gas prices, Chesapeake has directed a significant portion of its technological and leasehold acquisition expertise during the past two years to identify, secure and commercialize new unconventional liquids-rich plays. To date, Chesapeake has built leasehold positions and established production in multiple liquids-rich plays on approximately 5.1 million net leasehold acres with 5.6 billion bbls of oil equivalent (bboe) (34 tcfe) of risked unproved resources and 17.5 bboe (105 tcfe) of unrisked unproved resources. As a result of its success to date, Chesapeake expects to increase its oil and natural gas liquids production through its drilling activities to more than 150,000 bbls per day, or 20%-25% of total production, by year-end 2012 and to more than 250,000 bbls per day, or 30%-35% of total production, through organic growth by year-end 2015.

The following table summarizes Chesapeake's ownership and activity in its unconventional natural gas plays, its unconventional liquids-rich plays and its other conventional and unconventional plays. Chesapeake uses a probability-weighted statistical approach to estimate the potential number of drillsites and unproved resources associated with such drillsites.

In 2007, the company was the first to initiate large-scale horizontal drilling in the Mississippian Carbonate play in northern Oklahoma and southern Kansas. To date, Chesapeake has drilled 53 operated Mississippian horizontal wells and has participated in the drilling of 36 non-operated Mississippian horizontal wells on its inventory of approximately 1.1 million net acres. Chesapeake is currently drilling with five operated rigs in the Mississippian play and plans to increase its operated drilling activity in the Mississippian to seven rigs by the 2011 fourth quarter.

In 2010, the company was the first to identify the potential of the Utica Shale and to initiate large scale leasing efforts in Ohio and western Pennsylvania for the Utica. To date, the company has drilled nine operated Utica wells and is currently drilling with three operated rigs. Chesapeake plans to increase its operated drilling activity in the Utica to six rigs by the end of the 2011 third quarter. The company expects to initiate a joint venture process in the 2011 second half for both the Mississippian and Utica plays.

2011 First Quarter Average Realized Prices Benefit from Realized Hedging Gains of $488 Million, or $1.74 per Mcfe; Company Provides Update on Hedging Positions

Average prices realized during the 2011 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $5.31 per thousand cubic feet (mcf) and $63.20 per bbl, for a realized natural gas equivalent price of $5.99 per thousand cubic feet of natural gas equivalent (mcfe). Realized gains from natural gas hedging activities during the 2011 first quarter generated a $2.07 gain per mcf, while realized losses from oil hedging activities generated a $2.88 loss per bbl, for 2011 first quarter net realized hedging gains of $488 million, or $1.74 per mcfe.

By comparison, average prices realized during the 2010 first quarter (including realized gains or losses from natural gas and oil derivatives, but excluding unrealized gains or losses on such derivatives) were $6.31 per mcf and $67.70 per bbl, for a realized natural gas equivalent price of $6.80 per mcfe. Realized gains from natural gas and oil hedging activities during the 2010 first quarter generated a $1.81 gain per mcf and a $5.11 gain per bbl, for 2010 first quarter realized hedging gains of $399 million, or $1.71 per mcfe. The company's realized cash hedging gains since January 1, 2001 have been $7.0 billion, or $1.20 per mcfe, on average, for every mcfe produced during the past ten years.

To provide protection against potentially weak natural gas prices in 2011 and the first half of 2012, Chesapeake has entered into hedges for a portion of its production in those two years. Depending on changes in natural gas and oil futures markets and management's view of underlying natural gas and oil supply and demand trends, Chesapeake may increase or decrease some or all of its hedging positions at any time in the future without notice. The following table summarizes Chesapeake's 2011 and 2012 open swap positions as of May 2, 2011.

In addition to the open hedging positions disclosed above, as of May 2, 2011 (as detailed below), the company had an additional $725 million and $42 million of net hedging gains on closed contracts and premiums collected on call options that will be realized in 2011 and 2012, respectively.

Assuming future NYMEX natural gas settlement prices average $4.50 and $5.50 per mcf for 2011 and 2012, respectively, and including the effect of the company's open hedges, closed contracts and previously collected call premiums, the company estimates its average NYMEX natural gas prices will be $5.98 and $5.60 per mcf for 2011 and 2012, respectively. Additionally, assuming future NYMEX oil settlement prices average $100 per bbl for 2011 and 2012, the company estimates its average NYMEX oil prices will be $96.22 and $95.80 per bbl for 2011 and 2012, respectively. These estimates do not include the effect of gathering costs and basis differentials, which include the effect of lower-priced NGLs on the company's reported realized liquids prices.

Details of the company's quarter-end hedging positions, including sold call options, are provided in the company's Form 10-Q and Form 10-K filings with the SEC and current positions are disclosed in summary format in the company's Outlook. The company's updated forecasts for 2011 and 2012 are attached to this release in the Outlook dated May 2, 2011, labeled as Schedule "A," which begins on page 21. The Outlook has been changed from the Outlook dated February 22, 2011, attached as Schedule "B," which begins on page 25, to reflect various updated information.

Chesapeake Provides Update on 25/25 Plan; Company Agrees to Monetize Certain Mid-Continent Assets through its Ninth Volumetric Production Payment

On January 6, 2011, Chesapeake announced its 25/25 Plan, which outlined the company's plan to reduce its long-term debt by 25% during 2011-12 while also delivering natural gas and oil production growth of 25% during these two years. The company expects to achieve the reduction in debt primarily with proceeds from asset monetizations and from substantially reduced leasehold spending during this period.

Two recent transactions reflect the company's substantial progress already made in implementing its 25/25 Plan. On February 11, 2011, the company closed its Niobrara Shale cooperation agreement through which CNOOC Limited (NYSE:CEO; SEHK:00883) purchased a 33.3% undivided interest in Chesapeake's 800,000 net natural gas and oil leasehold acres in the DJ and Powder River Basins in Colorado and Wyoming for approximately $4,750 per net acre. The company received approximately $570 million in cash at closing, and CNOOC has agreed to fund 66.7% of Chesapeake's share of drilling and completion costs until an additional $697 million has been paid, which Chesapeake expects to occur by year-end 2014.

In addition, on March 31, 2011, Chesapeake closed the sale of its upstream and midstream assets in the Fayetteville Shale to BHP Billiton, for net proceeds of approximately $4.65 billion in cash.

Proceeds from the transactions above will fund the purchase of approximately $1.865 billion of the company's senior notes and contingent convertible senior notes in May 2011 pursuant to company tender offers for the notes. Combined with the $140 million of contingent convertible senior notes purchased by Chesapeake in privately negotiated transactions in the past 60 days, Chesapeake will have retired an aggregate principal amount of approximately $2.005 billion of senior notes and contingent convertible senior notes in 2011. The company may negotiate or tender for the acquisition of additional senior notes and contingent convertible senior notes later in 2011 or in 2012.

Moreover, through a recently disclosed planned recapitalization of Frac Tech Services, LLC, Chesapeake anticipates receiving a cash distribution of approximately $200 million and will increase its ownership of the company's equity from 26% to 30%. The Frac Tech recapitalization transaction is expected to close in the 2011 second quarter and the company believes that by year-end 2011, the value of its equity in Frac Tech will be worth up to $1.5 billion.

Additionally, Chesapeake has agreed to monetize certain of its producing assets in the Mid-Continent through a ten-year volumetric production payment (VPP) to an affiliate of Barclays PLC (NYSE:BCS; LSE:BARC) for proceeds of approximately $850 million. The transaction includes approximately 180 bcfe of proved reserves and approximately 80 mmcfe per day of current net production. Chesapeake has retained drilling rights on the properties below currently producing intervals and outside of existing producing wellbores and the production "tail" beyond ten years. The transaction will be Chesapeake's ninth VPP and is expected to close in the 2011 second quarter. Inclusive of the pending VPP sale and the company's eight previously closed VPPs, the company will have sold 1.215 tcfe of proved reserves for total proceeds of $5.619 billion, for an average sales price of $4.62 per mcfe.

Chesapeake Highlights its Oilfield Service Vertical Integration Strategy and Estimates that its Oilfield Service Assets Are Worth Approximately $7.0 Billion

Chesapeake has built a large inventory of low-risk natural gas and oil resources which the company plans to develop aggressively in the decades ahead. As a result, the company will consistently utilize a large and growing amount of oilfield services for this resource development. In the next decade alone, Chesapeake's gross drilling and completion expenditures may reach $100 billion. This high level of planned drilling activity will create considerable value for the providers of oilfield services and Chesapeake's strategy is to capture a portion of this value for its shareholders rather than transfer it to third-party vendors. In addition, the company utilizes its service company operations as a hedge against oilfield service inflation.

To date, Chesapeake has invested in drilling rigs, compression equipment, rental tools, water management equipment, trucking, midstream services and most recently, fracture stimulation equipment. Chesapeake's industry-leading drilling and completion activities require a high level of planning and project coordination that the company believes is best accomplished through vertical integration and ownership of a significant portion of the oilfield services it utilizes. This vertical integration approach also creates a multitude of cost savings, an alignment of interests, operational synergies, greater capacity of equipment, increased safety and better coordinated logistics. In addition, Chesapeake's control of a large portion of the oilfield service equipment it utilizes provides unique advantages in accelerating the timing of its leasehold development and therefore accelerating the creation of present value from its vast inventory of undeveloped properties.

As an extension of this strategy, Chesapeake recently agreed to acquire and has now commenced a cash tender offer to purchase all of the outstanding shares of Bronco Drilling Company, Inc. (NASDAQ: BRNC) for $315 million, or $11 a share. The cash tender offer will expire on May 23, 2011. The acquisition includes 22 high-quality drilling rigs primarily operating in the Williston and Anadarko basins and has support from Bronco's two largest shareholders, who collectively own 32% of Bronco's stock.

Based on projected levels of Chesapeake's oilfield service company unconsolidated cash flow from operations of approximately $1.0 billion in 2012, Chesapeake believes that the combined value of its oilfield service company assets, including the value of its investment in Frac Tech, is worth approximately $7.0 billion. The company is in the process of evaluating various alternatives to partially monetize its oilfield service assets and expects to achieve such a monetization in 2012.

Conference Call Information

A conference call to discuss this release has been scheduled for Tuesday, May 3, 2011, at 9:00 a.m. EDT. The telephone number to access the conference call is **913-981-5539** or toll-free **888-820-9417**. The passcode for the call is **8789033**. We encourage those who would like to participate in the call to dial the access number between 8:50 and 9:00 a.m. EDT. For those unable to participate in the conference call, a replay will be available for audio playback from 1:00 p.m. EDT on Tuesday, May 3, 2011 through midnight EDT on Tuesday, May 17, 2011. The number to access the conference call replay is **719-457-0820** or toll-free **888-203-1112**. The passcode for the replay is **8789033**. The conference call will also be webcast live on Chesapeake's website at www.chk.com in the "Events" subsection of the "Investors" section of the website. The webcast of the conference call will be available on Chesapeake's website for one year.

This news 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 natural gas and oil reserves and resources, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned drilling activity, drilling and completion costs, anticipated asset sales, projected cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures of the estimated realized effects of our current hedging positions on future natural gas and oil sales are based upon market prices that are subject to significant volatility. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this news release, and we undertake no obligation to update this information.

Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in our 2010 Form 10-K filed with the U.S. Securities and Exchange Commission on March 1, 2011. These risk factors include the volatility of natural gas and oil prices; the limitations our level of indebtedness may have on our financial flexibility; declines in the values of our natural gas and oil properties resulting in ceiling test write-downs; the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures; inability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; hedging activities resulting in lower prices realized on natural gas and oil sales, the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations; a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices; drilling and operating risks, including potential environmental liabilities; legislative and regulatory changes adversely affecting our industry and our business; general economic conditions negatively impacting us and our business counterparties; transportation capacity constraints and interruptions that could adversely affect our cash flow; and adverse results in pending or future litigation.

Our production forecasts are dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties.

The SEC requires natural gas and oil companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of natural gas and oil that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. In this news release, we use the terms "risked and unrisked unproved resources" to describe Chesapeake's internal estimates of volumes of natural gas and oil that are not classified as proved reserves but are potentially recoverable through exploratory drilling or additional drilling or recovery techniques. These are broader descriptions of potentially recoverable volumes than probable and possible reserves, as defined by SEC regulations. Estimates of unproved resources are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of actually being realized by the company. We believe our estimates of unproved resources are reasonable, but such estimates have not been reviewed by independent engineers. Estimates of unproved resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

The company calculates the standardized measure of future net cash flows of proved reserves only at year end because applicable income tax information on properties, including recently acquired natural gas and oil interests, is not readily available at other times during the year. As a result, the company is not able to reconcile interim period-end PV-10 values to the standardized measure at such dates. The only difference between the two measures is that PV-10 is calculated before considering the impact of future income tax expenses, while the standardized measure includes such effects. Year-end standardized measure calculations are provided in the financial statement notes in our annual reports on Form 10-K.

Chesapeake Energy Corporation is the second-largest producer of natural gas, a Top 15 producer of oil and natural gas liquids and the most active driller of new wells in the U.S. Headquartered in Oklahoma City, the company's operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Three Forks/Bakken and Utica unconventional liquids plays. The company has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. Chesapeake's stock is listed on the New York Stock Exchange under the

symbol CHK. Further information is available at www.chk.com where Chesapeake routinely posts announcements, updates, events, investor information, presentations and press releases.

Commodity Hedging Activities

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

1. Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
2. Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.
3. Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market prices falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.
4. Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
5. Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

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. Since the latter half of 2009 through May 2, 2011, the company has taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to its counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with strike prices above the then current market price. This effectively allowed the company to sell out-year volatility through call options at terms acceptable to Chesapeake in exchange for straight natural gas swaps with strike prices in excess of the market price for natural gas at that time.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices.

Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Realized gains (losses) are comprised of settled trades related to the production periods being reported. Unrealized gains (losses) are comprised of both temporary fluctuations in the mark-to-market values of non-qualifying trades and settled values of non-qualifying derivatives related to future production periods.

At May 2, 2011, the company has the following open natural gas swaps in place for 2011 and 2012, excluding contracts that will be novated with VPP #9. In addition, the company currently has $593 million of net hedging gains related to closed natural gas contracts and premiums collected on call options for future production periods.

Commodity Hedging Activities

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

1. Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
2. Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.
3. Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market prices falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.
4. Knockout swaps: Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty's exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.
5. Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin basis protection swaps, which typically have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which typically have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

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. Since the latter half of 2009 through February 22, 2011, the company has taken advantage of attractive strip prices in 2012 through 2017 and sold natural gas and oil call options to its counterparties in exchange for 2010, 2011 and 2012 natural gas swaps with strike prices above the then current market price. This effectively allowed the company to sell out-year volatility through call options at terms acceptable to Chesapeake in exchange for straight natural gas swaps with strike prices in excess of the market price for natural gas at that time.

Chesapeake enters into natural gas and oil derivative transactions in order to mitigate a portion of its exposure to adverse market changes in natural gas and oil prices. Accordingly, associated gains or losses from the derivative transactions are reflected as adjustments to natural gas and oil sales. All realized gains and losses from natural gas and oil derivatives are included in natural gas and oil sales in the month of related production. In accordance with generally accepted accounting principles, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). Realized gains (losses) are comprised of settled trades related to the production periods being reported. Unrealized gains (losses) are comprised of both temporary fluctuations in the mark-to-market values of non-qualifying trades and settled values of non-qualifying derivatives related to future production periods.

The company currently has the following open natural gas swaps in place for 2011 and 2012. In addition to the open swap positions disclosed below, at February 22, 2011, the company had $687 million of net hedging gains related to closed natural gas contracts and premiums collected on call options for future production periods.

SOURCE: Chesapeake Energy Corporation

Chesapeake Energy Corporation
Investor Contacts:
Jeffrey L. Mobley, CFA, 405-767-4763
jeff.mobley@chk.com
or
John J. Kilgallon, 405-935-4441
john.kilgallon@chk.com
or
Media Contact:
Jim Gipson, 405-935-1310
jim.gipson@chk.com

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