Steven C. Dixon
Executive Vice President - Operations
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February 18, 2008

Securities and Exchange Commission
100 F Street, NE
Washington, DC 20549-1090
Attention: Nancy M. Morris, Secretary

Re: Concept Release on Possible Revisions to the Disclosure Requirements Relating to Oil and Gas Reserves, Release Nos. 33-8870; 34-56945 (Dec. 12, 2007) ("Concept Release"), File No. S7-29-07

Ladies and Gentlemen:

Chesapeake Energy Corporation submits this letter in response to the Securities and Exchange Commission's request for comment on possible revisions of the disclosure requirements relating to oil and natural gas reserves.

Chesapeake is the third largest producer of natural gas in the United States (first among independents) and the most active driller of new wells in the U.S. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S. east of the Rocky Mountains. As of December 31, 2007, we owned interests in approximately 38,500 producing oil and natural gas wells and had 10.9 trillion cubic feet equivalent, or tcfe, of proved reserves, of which 93% was natural gas and all of which was onshore. During 2007, Chesapeake continued the industry's most active drilling program and drilled 1,992 gross (1,695 net) operated wells and participated in another 1,679 gross (224 net) wells operated by other companies. We have built the nation's largest onshore leasehold (13.2 million net acres) and 3-D seismic (19.2 million acres) inventories. Of our 6,400 employees, over 400 are petroleum engineers, geologists and other geoscience professionals.

We welcome this opportunity to participate in reshaping the Commission's oil and natural gas reporting rules, initially developed some 30 years ago, to be more reflective of current industry technology and to provide investors with more transparent information. We believe investors, consumers, market participants and policymakers should have the most reliable data available about today's energy resource realities and tomorrow's potential.

Chesapeake provides comment below on several of the questions (reproduced in bold) posed in the Concept Release. We have focused on our areas of greatest interest, especially the reporting of natural gas reserves. Our recommendations include the following:

- The pricing method used to value oil and natural gas reserves should be changed from a single-day spot price to an average of 12-month futures strip prices.

- Reserves from all sources should be reportable if they are economic to produce. Oil and natural gas reserves from unconventional reservoirs should be defined and standards developed for reporting these reserves.

- Disclosure of probable oil and natural gas reserves in Commission filings should be permitted in accordance with newly developed guidance. This will ensure consistency in reporting and provide readers insight into a company's future prospects.

- An oversight board should be established to provide standards for estimating oil and natural gas reserves, with the authority to update guidance in response to new technologies.

- The Commission should develop a transition plan to migrate from a rules-based to a principles-based system of oil and natural gas reporting.

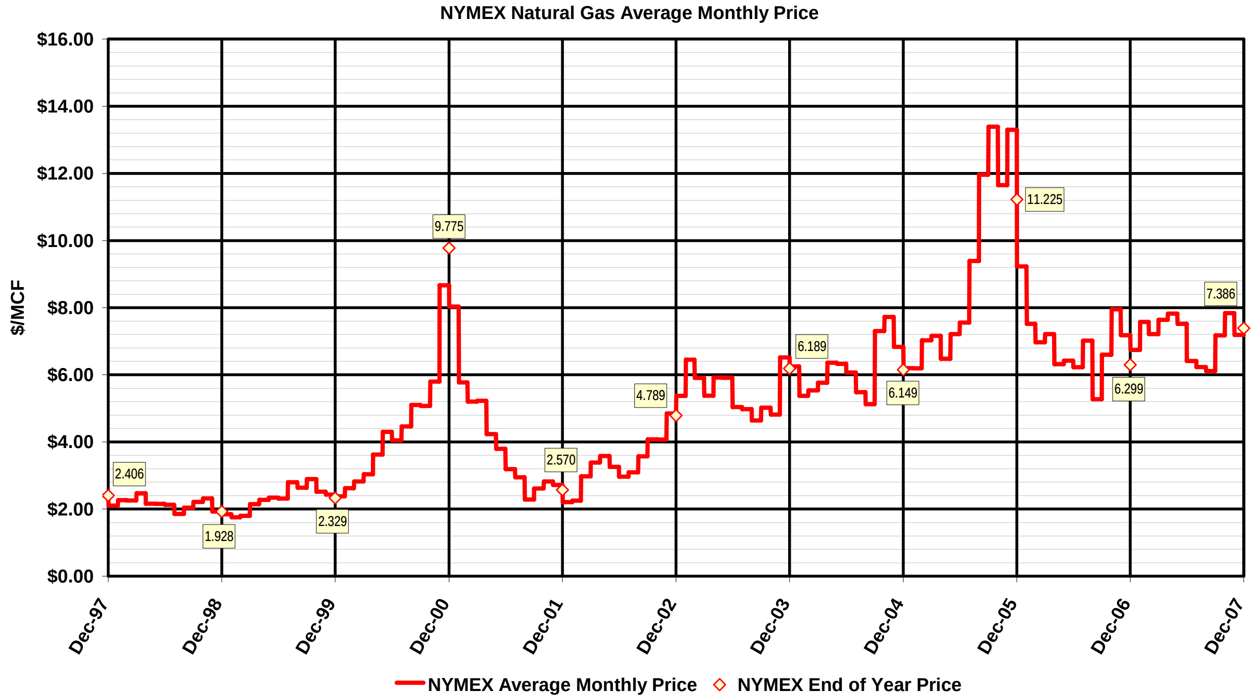
I. PRICING OF RESERVES

> **Should we reconsider requiring companies to use a sale price in estimating reserves? If so, how should we establish the price framework? Should we require or allow companies to use an average price instead of a fixed price or a futures price instead of a spot price? Should we allow companies to determine the price framework? How would allowing companies to use different prices affect disclosure quality and consistency? Regardless of the pricing method that is used, should we allow or require companies to present a sensitivity analysis that would quantify the effect of price changes on the level of proved reserves?**

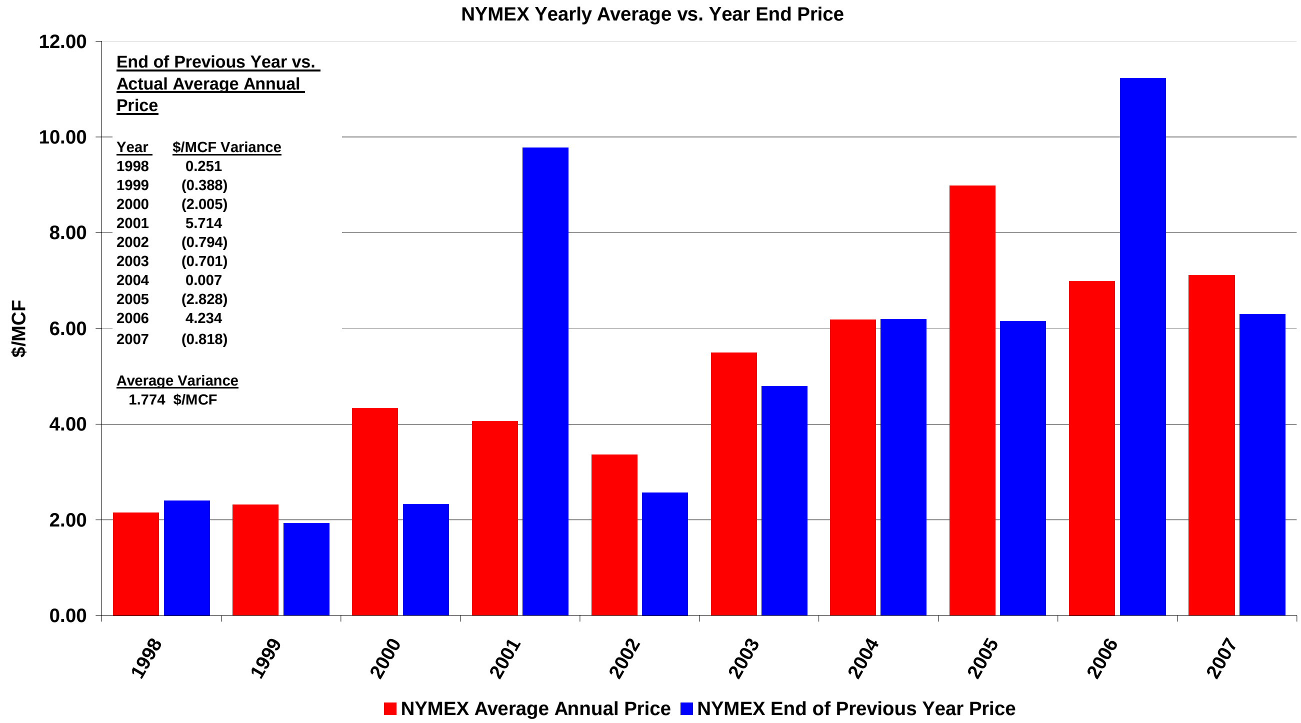
The reserve base of oil and natural gas exploration and production companies consists of crude oil and natural gas in the ground that, over time, will be produced and generally sold at market-sensitive prices. These prices, especially the prices for natural gas, are subject to sudden and wide fluctuations based on a variety of factors, including weather conditions, supply and demand imbalances, the price and availability of alternative fuels, political conditions, interruptions in transportation capacity and numerous other factors. In light of this volatility, using the price of the commodity on a single-day at the end of a period to measure oil and natural gas reserves for financial reporting purposes, as currently required, does not, we believe, yield a fair representation of reserve quantities or reserve base value. While we acknowledge that the disclosures prescribed by FAS 69 were not intended to provide investors with a fair market value of reserves, we believe that investors utilize these disclosures in assessing value, and as such, the disclosures provided should be based on a fair assessment of future expectations.

In addition to yielding a poor approximation of actual reserve value, we believe that the use of a single-day price has arbitrary effects on the financial statements of companies in our industry, particularly those that utilize the full-cost method of accounting for oil and natural gas reserves. Companies following the full-cost method are required to calculate a ceiling test at the end of each quarter. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues, less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. To the extent an excess exists, a full-cost company is generally required to write off the excess, less deferred income taxes, as an expense. In calculating future net revenues, full-cost companies are generally required to use prices as of the end of the applicable quarterly period. This requirement can result in an adverse financial accounting implication associated with write-downs of assets as a result of the volatility of commodity prices in situations where there is no substantive decline in the value of the oil and gas properties.

The red line in the chart below depicts average monthly natural gas prices on the New York Mercantile Exchange (the "NYMEX") for the ten-year period from January 1998 through December 2007. The chart also provides the NYMEX natural gas price as of the end of each year during that period. It is clear that this single-day price has not been an accurate predictor of the price of natural gas in the following year or in later years. In fact, in several of the past ten years, this end-of-year price has not closely approximated the historical average price for even the month of December.



The following chart further illustrates this point. The red bars depict the average annual price of natural gas on the NYMEX during the ten-year period from January 1998 through December 2007. The blue bars show the end-of-year price of the preceding year, held flat until the next end-of-year price. The difference between the red and the blue bars in each year confirms that natural gas assets have been inaccurately valued, sometimes very significantly, in almost every year in the past decade. For example, at year-end 2000, natural gas assets were evaluated based on a natural gas price of $9.78 per mcf. The average price during 2001, however, was just over $4.00 per mcf, a sizeable overstatement of value. The reverse occurred in 2005 with average 2005 prices far exceeding the 2004 end-of-year price. Again in 2006, the end-of-year 2005 price far exceeded prices actually received during 2006. Only in three of the past ten years does the end-of-year pricing remotely approximate the average price for the next year.



Our discussion with industry peers has found universal agreement that the current pricing framework should be changed. There is less agreement on which one of several alternatives would be the most effective. Alternatives include (i) the historical average price for the most recent year, (ii) the average of 12-month futures strip prices (a "12-month strip price"), and (iii) a longer futures strip price, such as five years. We believe any of these alternatives is better than the existing single-day price, but for natural gas, we support using a 12-month strip price.

12-Month Strip Price

Forward pricing, we believe, is a superior alternative for measuring oil and natural gas reserves. Futures prices are set by a liquid and active market and are publicly available. Commodity markets have changed dramatically with deregulation of the industry, and buyers and sellers of oil and natural gas now have the opportunity and ability to lock into long-term pricing. Forward-looking prices should more accurately reflect the price to be received, at least during the first year of production of proved reserves, than an historical price, whether for a single-day or some period. Using the average futures price over 12 months would smooth out the volatility of daily prices, but would not extend so far into the future as to become overly speculative. We believe pricing off a 12-month strip would also mitigate the potential for unwarranted write-downs caused by short-term price fluctuations.

II. RESERVE ESTIMATES FOR UNCONVENTIONAL FORMATIONS

Should we consider eliminating any of the current exclusions from oil and gas activities? How could removing these exclusions affect disclosure quality?

The distinction between proved and unproved reserves has become increasingly blurred as the Commission's definition of proved reserves has not kept pace with the industry's ability to find, evaluate and produce natural gas reserves from unconventional reservoirs. While the industry has long known that fractured carbonates, tight sands and shales contain natural gas, it has only been the recent arrival of higher natural gas prices and greatly improved drilling and completion technologies that has made developing many of these reservoirs economical. However, because these reserves often lie in reservoirs that are continuous for tens of miles and the Commission definition of proved reserves only allows for the recognition of proved undeveloped reserves as direct offsets to producing wells in a particular formation, significant reserves of natural gas are not captured in the Commission's current definition of proved reserves. The substantial value of unproved reserves in unconventional reservoirs is evidenced by companies routinely valuing and paying for unproved reserves in today's acquisition market.

According to an estimate released in May 2007 by the U.S. Department of Energy, 40% of domestic U.S. natural gas production now comes from unconventional formations. The Energy Information Administration estimates this figure to be 45%, and we believe it will likely exceed 60% within the next decade. At Chesapeake, the most aggressive developer of unconventional reservoirs over the past five years, more than 50% of our natural gas production now comes from unconventional reservoirs and that percentage will continue increasing in the years ahead. Rule 4-10 of Regulation S-X, however, excludes from the definition of proved reserves “crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources,” not even recognizing the existence of natural gas shales.

While the Commission staff has allowed some reserve volumes of natural gas from unconventional formations to be reported as proved, we believe clear, comprehensive standards should be adopted to permit the reporting of proved reserves associated with unconventional reservoirs. The lack of uniform reporting guidance for reserves associated with unconventional formations has created the potential for large reporting inconsistencies among registrants and estimates that understate this important source of natural gas, perhaps leading to poor public policy decisions as a consequence.

Defining Unconventional Resources

Economically commercial reserves are produced today from shale, coal and other formations with matrix permeability so low that proving pressure communication between wells is not feasible. Hydrodynamic effects are not present in these formations. To account for reserves from these formations, we propose not only the elimination of the exclusions, but the adoption of a uniform definition of “unconventional reservoirs.” Once defined, guidelines specific to these important and growing reserves should be formulated.

In the 1995 U.S.G.S National Assessment of U.S. Oil and Gas Resources, the U.S. Geological Survey described unconventional reservoirs, or "continuous-type accumulations," as follows:

> *Continuous-type accumulations are essentially large single fields having spatial dimensions equal to those of plays. Continuous-type accumulations cannot be represented in terms of discrete, countable entities delineated via down-dip hydrocarbon-water contacts, as are conventional fields. The identification of a continuous-type hydrocarbon accumulation is based on an enduring concept, the geologic settings of the accumulation. Common geologic characteristics of a continuous-type accumulation include occurrence down-dip from water-saturated rocks, lack of obvious trap and seal, cross cutting of lithologic boundaries, large aerial extent, relatively low matrix permeability, abnormal pressure (either high or low), and close association with source rocks.*

This description, used in combination with the following from the American Association of Petroleum Geologist Bulletin V.86, November 2003, can serve as the foundation of a Commission definition of “unconventional reservoirs”:

> *[T]here is a fundamentally important geologic distinction: conventional gas resources are buoyancy-driven deposits, occurring as discrete accumulations in structural and stratigraphic traps, whereas unconventional gas resources are generally not buoyancy-driven accumulations. They are regionally pervasive accumulations, most commonly independent of structural and stratigraphic traps.*

Need for Guidance in Reporting Proved Undeveloped Reserves (PUD) from Unconventional Reservoirs

The Commission's existing definition of proved reserves describes conventional reservoirs. It simply does not take into account the characteristics of unconventional reservoirs. As noted in the AAPG description quoted above, unconventional reservoirs are not buoyancy driven. The permeability in these reservoirs is too low for water to dominate production or to allow for gravity segregation. The extreme low permeability of unconventional formations is not conducive to establishing pressure communication between wells, a necessary marker of proved reserves under existing Commission rules. Yet unconventional reservoirs are known to be regionally extensive and can be shown to be productive across large areas.

The dilemma faced by petroleum engineers needing to report on oil and natural gas reserves in unconventional formations without relevant rules was brought into sharp focus in a Commission staff review letter dated July 9, 2007 to Parallel Petroleum Corporation. With respect to booking proved undeveloped reserves for unconventional reservoirs, the staff wrote, “[Y]ou should limit estimates of proved undeveloped reserves from future horizontal wells to two parallel offset wells to a productive horizontal well. Please confirm that in the future you will limit proved undeveloped reserves from horizontal wells to these amounts *unless you have demonstrated productive continuity* *through pressure communication between wells more than an offset location away and on either side of a future horizontal well.*" (Emphasis added.)

In our view, establishing pressure communication to prove continuity of production is not applicable to unconventional reserves, and proved undeveloped reserves for unconventional reservoirs should not be limited to an arbitrary 2:1 parallel offset rule. The guidance contained in the Parallel Petroleum correspondence has only added to the confusion of producers and engineering firms in regard to booking PUDs offsetting horizontal producing wells.

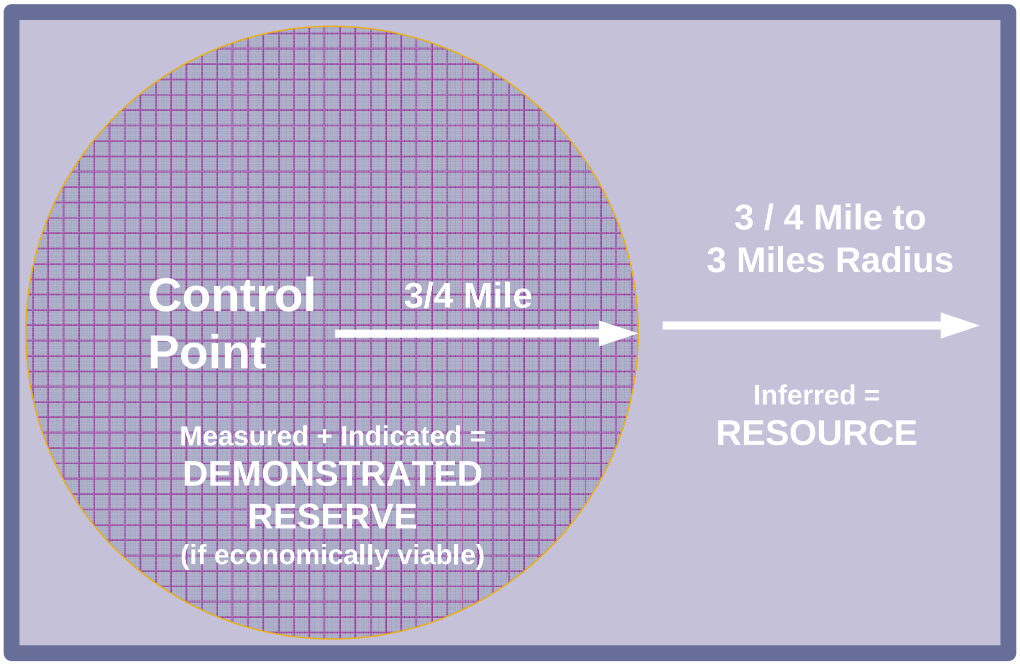
The need exists for consistent comprehensive guidance in regard to booking proved undeveloped locations, especially PUDs in unconventional reservoirs to be developed by horizontally drilled wells.

A Proposed Approach—Borrow from Coal Reserve Reporting

After reviewing U.S.G.S. Circular 891 and the Commission's Industry Guide 7 and discussing options with mining industry experts, Chesapeake recommends that the Commission adapt its existing guidance for reporting coal reserves to the reporting of oil and natural gas reserves from unconventional reservoirs.

In our view, similarities exist between extracting oil and natural gas from unconventional rocks, rocks that are laterally continuous over vast areas and that are not significantly influenced by structure or stratigraphy, and mining coal. Coal mining requires data points (drill holes, mine shafts, outcrops) to obtain measurement of thickness, elevation, coal rank and quality. These data are then applied to a larger area to calculate the volume of coal reserves. The oil and gas industry does exactly the same thing in estimating reserves from unconventional formations. We discover the thickness; we map the aerial extent using control points and seismic information; we obtain rock and gas samples; and we evaluate the rock to determine gas-in-place. It is our opinion, based upon our research, that we routinely collect more data and higher quality data than does the coal mining industry.

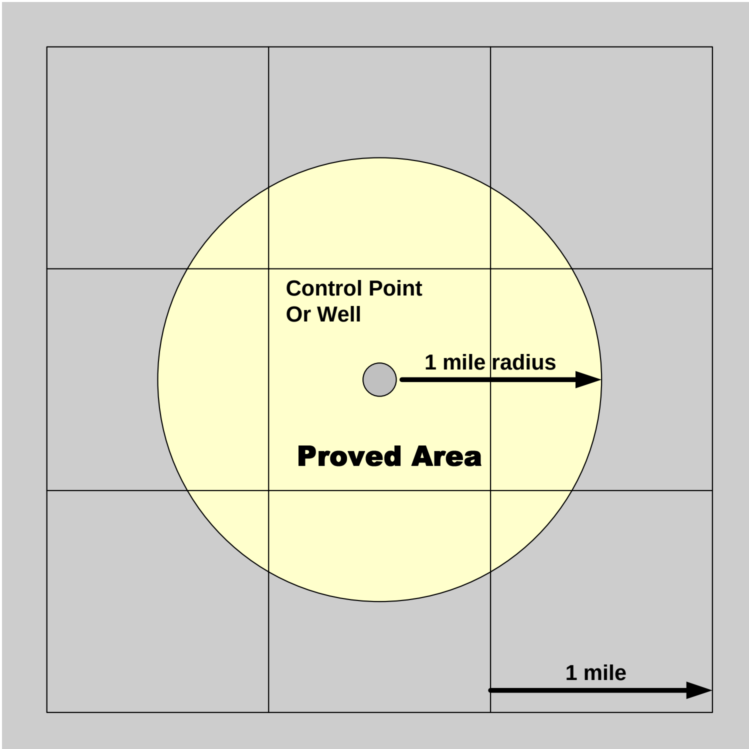
Although some of the nomenclature varies, the coal mining industry books proved reserves based upon a ¾ mile radius around a known control point. The term used within that industry is "demonstrated reserve" which is a combination of "measured" (that which lies within ¼ mile of the control point) and "indicated" (that which lies between ¼ to ¾ mile from the control point). In all instances, data must suggest the extraction of the coal is economic. The schematic below illustrates the control-point method of defining proved coal reserves.



In the coal mining industry, a change in thickness of a few inches or a change in elevation of a few feet is critical to project economics. In the oil and gas industry, most unconventional reservoirs are typically tens to hundreds of feet thick with little to no change in thickness over vast areas. Even when thickness does vary, it generally takes a significant change to alter overall economic viability. Structural changes have to be in the order of hundreds to thousands of feet to affect project commerciality. If deposits as thin and variable as coal can be measured in the manner prescribed in Industry Guide 7, we believe this existing reporting system can be used to define unconventional oil and natural gas reservoirs that are substantially thicker and more laterally pervasive than most commercial coal deposits in the U.S.

We believe a proved area developed by a known commercial control point within an unconventional oil or natural gas reservoir can reliably be justified at a distance of one mile in radius. In fact, one mile is extremely conservative when the nature of the geology is considered. One-mile offset PUDs are commonplace in conventional oil and natural gas reservoirs, and conventional reservoirs are more variable than unconventional reservoirs in structure, stratigraphy, water saturations, thickness and permeability.

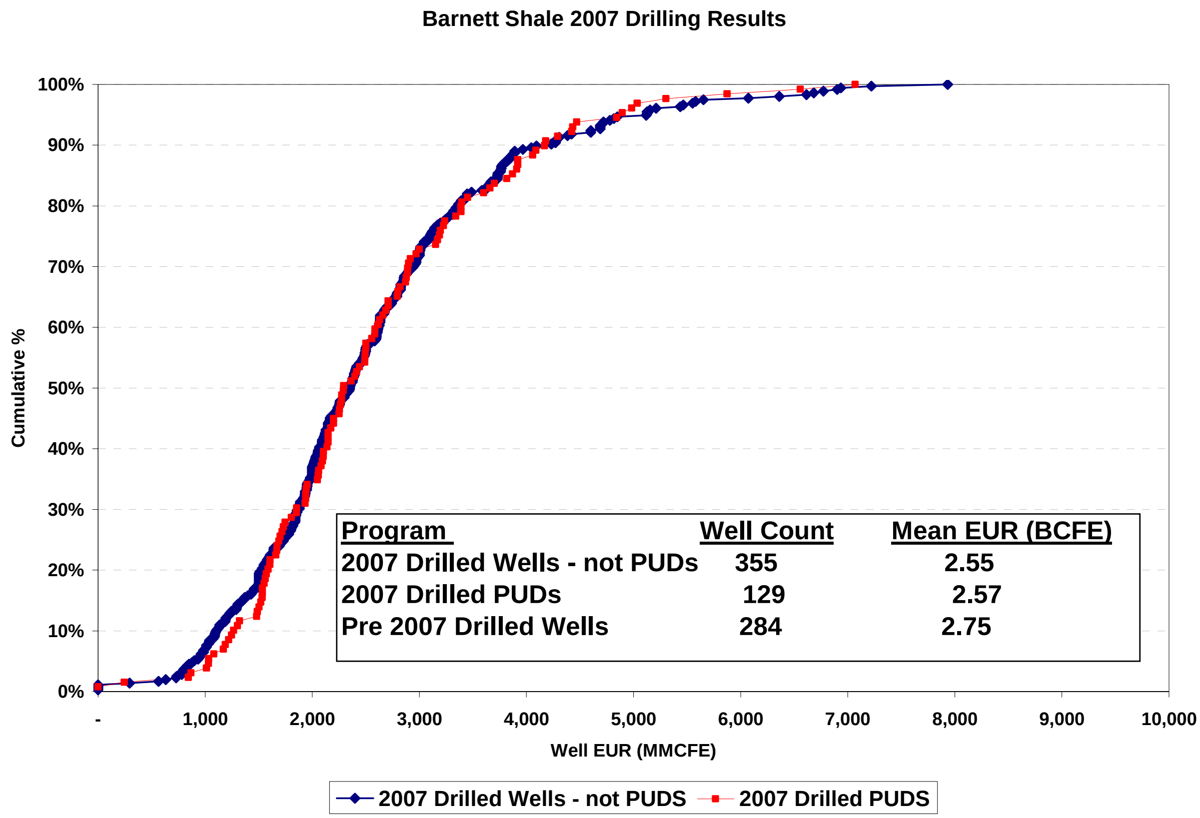
This approach, illustrated below, could establish a proved area only if supported by sufficient engineering and geologic data and control. In some instances, seismic or other data might suggest a different shape or diameter, but never, in our view, should the proved area exceed one mile from the point of control.



Development of the reserve volume within the proved area would be based upon all technical data available, acceptable economic parameters and prevailing well spacing. This approach would not mandate a certain number of offsets. The reporting company would determine the proper plan of development within a proved area. The number and location of the undrilled locations associated with a plan of development, recoveries per well and overall recovery factors would have to be supported by engineering, petrophysical and geological data. Seismic data could be used as additional support but should not be mandated. The reserve volume generated by this plan of development would be booked as proved undeveloped.

To further verify the reasonableness of this approach for unconventional reservoirs, we have analyzed our 2007 drilling results in the Barnett and the Fayetteville shale plays. We believe both of these formations and plays fit the proposed definition of unconventional resources.

The chart below shows no difference in risk or uncertainty for the north-central Texas Barnett Shale wells we drilled in 2007, whether they were defined as PUDs or as unproved reserves under existing rules (wells not booked as proved prior to drilling are referred to below as “New Drill Adds”). These results suggest that the area within the Barnett currently considered proved under existing Commission rules is significantly smaller than the facts demonstrate. Additionally, 479 out of 484 wells we drilled in the Barnett Shale in 2007 were productive. This is a geologic success ratio of 99%, far exceeding any conventional play. No difference in success ratio was seen between PUDs and non-PUDs.



The Fayetteville Shale play in central Arkansas is at least two years behind the Barnett Shale in terms of well count and explored play boundaries, yet the geologic success of the 308 Fayetteville wells in which Chesapeake participated in 2007 was 98%. The average estimated ultimate recovery (EUR) of the drilled PUDs was 2.1 bcfe per well compared to 1.9 bcfe per well for the wells not booked as PUDs prior to drilling. Again, even in this fairly immature unconventional play, the continuous nature of the formations greatly reduces risk and uncertainty.

Both of these actual case studies support the use of a proved-area approach to report proved undeveloped natural gas reserves in an unconventional play. For companies that have significant unconventional oil and natural gas reserves, the recognition of these now unreported PUDs would have a potentially material effect on financial reporting.

III. A PRINCIPLES-BASED FRAMEWORK

What aspects of technology should we consider in evaluating a disclosure framework? Is there a way to establish a disclosure framework that accommodates technological advances?

Technology in the oil and gas industry has advanced while the Commission's oil and gas reporting rules have been largely static. Technology that is commonplace in the industry today and on which companies rely in budgeting capital expenditures for future development is not recognized by the Commission as a reliable reporting platform for proved reserves. To make a meaningful change will require a paradigm shift in reporting methodology.

Rather than list technologies that are acceptable for determining and reporting reserves, we recommend that the Commission follow a principles-based model of reporting. Validity of proved reserve estimates should never be about a single log or a particular seismic interpretation, but rather should reflect a preponderance of all of the technical evidence and data interpretation. Commission staff advice has sometimes acknowledged this point. The staff's Current Issues and Rulemaking Projects Outline of November 14, 2000 says, "The use of high quality, well calibrated seismic data can improve reservoir description . . . . However, seismic data is not an indicator of continuity of production and therefore, can not be the *sole* [emphasis added] indicator of additional proved reserves . . . ." We recommend that all technology be permitted in determining reserves. Let the cumulative evidence speak for itself without excluding a particular technology simply because it was developed, tested and shown to be accurate after the issuance of the latest rules.

This recommended "principles-based" approach builds upon the Commission staff's response to conditions in the deepwater Gulf of Mexico a few years ago. In response to evidence provided by operators, the staff allowed new technology to be used in regard to well tests validating reserves. The staff showed the flexibility to respond to changing conditions but then went on to limit its application to just this one region. This seemed arbitrary at the time and remains so in our view. The use of new technology should be permitted world-wide unless extreme specific circumstances indicate otherwise in an isolated area.

IV. DISCLOSURE OF PROBABLE RESERVES

Should the Commission consider allowing companies to disclose reserves other than proved reserves in filings with the SEC? If we were to allow companies to include reserves other than proved reserves, what reserves disclosure should we consider? Should we specify categories of reserves? If so, how should we define those categories?

Companies should have the option, but not the obligation, to report reserves other than proved reserves. To make the implementation manageable, Chesapeake recommends that:

- reporting of other than proved reserves be limited to probable reserves only, and
- guidelines be established for estimating and reporting probable reserves.

Probable Reserves Reporting – Why?

We believe the reporting of proved reserves only is misleading to investors, policymakers and natural gas consumers. We are particularly sensitive to the underreporting of U.S. natural gas resources and believe it may negatively influence all stakeholders. For policymakers and consumers, this approach creates a false perception that natural gas resources are scarce. For investors, we believe it deprives them of potentially the most important information considered by management in charting a company's course. They cannot see the company's operations and business strategy through management's eyes without this information. We recognize, however, the risk of allowing highly uncertain reserves to be reported in a registrant's Commission filings. We therefore advocate limiting disclosure to probable reserves.

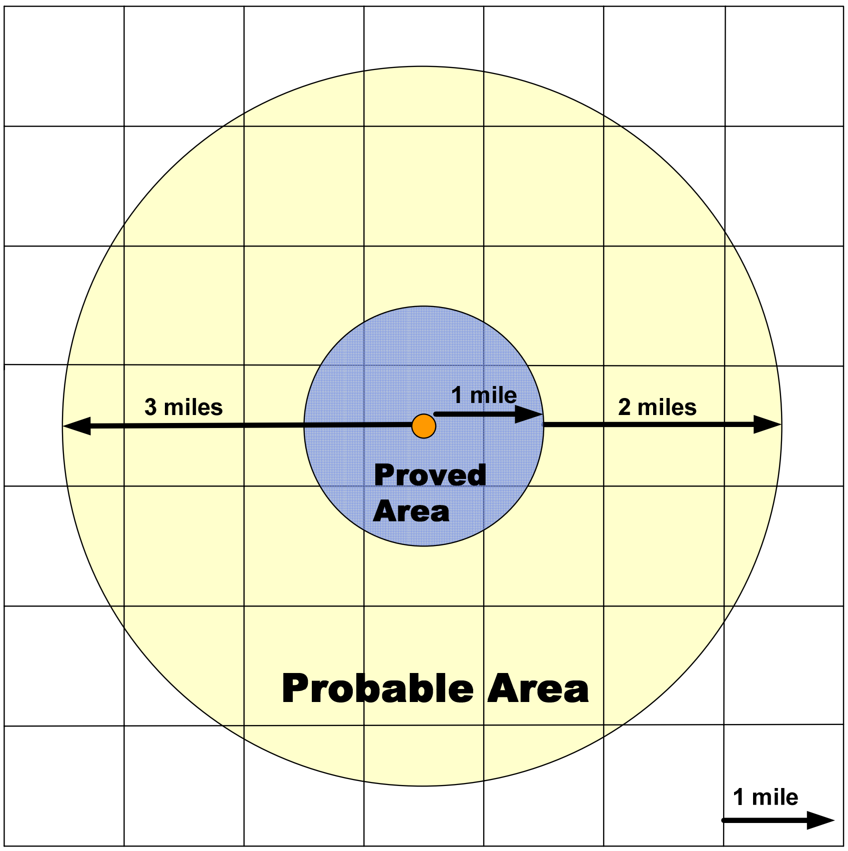
In addition to providing stakeholders with more useful information, we believe that the adoption of standards under which probable reserves are defined and reportable in Commission filings would bring disclosures in filed and non-filed documents closer together. There presently exists a two-tiered disclosure regime in which companies file Commission reports containing only proved reserve information and at the same time use a plethora of other communications (e.g., earnings releases, earnings calls, analyst presentations and investor and industry conferences) to provide much more “upside” information, information that is not consistent among industry participants and perhaps not equally accessible to all investors. We believe that the adoption of standards regarding probable reserves would require companies to follow more consistent reporting standards in their Commission reports and other communications.

Repeated studies by the Potential Gas Committee (PGS) and the U.S.G.S. have concluded that tremendous quantities of natural gas supply exist in the U.S.; however, the vast majority of this supply goes unreported in public company filings with the Commission. In its December 2004 report, the PGS concluded that of a 1,308 tcf U.S.-based future supply of natural gas, only 189 tcf constituted proved reserves. This PGS report recognized and incorporated known and emerging coal and shale plays at the time of its publication. Since then further advances in developing and defining unconventional reservoirs have been introduced. Current rules and exclusions compared to the expansion of unconventional reservoirs and production will serve to widen this gap even further. One consequence, we believe, is that our industry, and our company, is undervalued in the equity markets because value is not always appropriately given by investors for what can be very significant amounts of low-risk unproved reserves. Further, in the growing debate about how to best meet the country’s growing energy needs while also reducing potentially harmful greenhouse gas emissions, we believe natural gas is often ignored as a possible solution because it is always considered “scarce” as the industry under present rules can never show more than about a ten-year supply of proved reserves remaining. We believe better public policy decisions could be made if the true size of our nation’s natural gas reserves was better documented.

Probable Reserves Reporting Guidelines

For conventional reservoirs, we recommend that the Commission adopt a simple "two locations out" rule as the general standard if a company chooses to disclose probable reserves.

For reporting probable reserves from unconventional reservoirs, we recommend that the Commission expand its coal mining guidelines to cover oil and natural gas activity using a three-mile radius guide, as illustrated below.



Similar to the one-mile proved area we have recommended for reporting unconventional proved reserves, this additional two-mile ring would be a maximum distance, not a required one. Within the area, the appropriate engineering and geologic data would be required to support economic development. All available data, including seismic, would be viewed to support the probable area; however, by the very nature of being further removed from the last measured economic point, the probable reserves become less certain than proved reserves.

V. ADOPTION OF THE PETROLEUM RESOURCES MANAGEMENT SYSTEM

Should the Commission adopt all or part of the Society of Petroleum Engineers – Petroleum Resources Management System? If so, what portions should we consider adopting? Are there other classification

frameworks the Commission should consider? If the Commission were to adopt a different classification framework, how should the Commission respond if that framework is later changed?

The PRMS has been carefully scrutinized by numerous industry organizations, regulatory commissions and individuals. The body of work it represents and the effort to build consensus undertaken should not be ignored by industry producers or by the Commission. Chesapeake is in support of migrating to this more principles-based system or some variation thereof. However, we caution that this must be done in a logical and systematic way, allowing for an appropriate transition for industry and the Commission to respond to the demands and changes required. We believe the transition period could be as long as five years.

A transition plan is required for the following reasons:

1. Industry training: Not all producers, petroleum engineering firms or investors are currently aware of the requirements of the PRMS. They may not be well versed in how statistical calculations function, how correlations of variables need to be addressed and how aggregation issues affect final outcomes.

2. Proper tools: Not all producers and reserve estimators have the software required to implement PRMS principles. Time will be required to adopt these tools and to utilize them consistently and effectively.

3. Establishment of an oversight committee: Chesapeake supports the concept of establishing an oversight board, a reserve accounting standards board that would provide guidance to the oil and natural gas industry and the Commission. Such a board would be responsible for reviewing and updating guidance for estimating reserves, incorporating technology advances as appropriate. We note that SPE's Oil and Gas Reserves Committee is comprised of industry professionals with other employment obligations and may not be the best option for a standards-setting body. Other alternatives need to be discussed and considered during this transition period.

4. Talent constraints: Effectively implementing a principles-based reserve reporting system will place additional pressures on people resources within our industry. A new system has the potential to increase engineering, geologic and accounting requirements. As an industry, we are already in competition for professionals in short supply and this is projected to worsen in coming years as the vast majority of today's reservoir engineers reach retirement age.

5. Public Perception: Special attention must be paid to counteracting public suspicion of a new reporting system. The public must be assured that we will continue to have consistent, reliable reporting across our industry. We can not ignore public perception that our industry is untrustworthy. Any transition should proactively address this issue and attempt to insure that a reporting

system change is for the good of all interested parties, including consumers and investors.

While Chesapeake generally favors moving to the PRMS, we recommend that the full resource classification structure of PRMS not be adopted. It is overly burdensome and goes well beyond what is required for public reporting. Tracking of contingent and uneconomic resources is an issue for individual companies to weigh, not the Commission to mandate.

The PRMS document focuses on the use of statistics and greatly downplays the common industry approach of calculating reserves using deterministic methods. It does state that deterministic reserve estimates are acceptable. We believe deterministic methods must continue to be recognized. Stochastic calculations are not applicable to all situations and may be best served early in the decision-making process. Deterministic reporting is more straightforward, more understandable, more measurable and more auditable. Its "best estimate" approach has been utilized for decades within our industry. Any migration to a principles-based reporting system has to safeguard this time-honored method.

VI. CONCLUSIONS

We have recommended a number of changes in the Commission's disclosure requirements for oil and natural gas reserves, in each case with a view to implementing the changes in an orderly manner. These changes are summarized below.

- Chesapeake supports changing the pricing method used to value oil and natural gas reserves to an average of period-end 12-month futures strip prices.

- The source of oil and natural gas reserves is irrelevant. Reserves from all sources should be reportable if they are economic to produce.

- Oil and natural gas reserves from unconventional resources must be written into the Commission's definitions and standards to give producers proper credit for these volumes and to provide consumers, investors, market participants and policymakers the data to make informed decisions.

- Disclosure of probable oil and natural gas reserves should be allowed, but not mandated, in accordance with guidelines developed to insure consistency in reporting.

- Chesapeake supports the establishment of an oversight board that would provide standards for estimating oil and natural gas reserves, with the authority to update guidance in response to new technologies.

- The Commission should develop a transition plan to migrate from a rules-based to a principles-based system of oil and natural gas reporting.

Some of the changes, such as the use of a new pricing mechanism, could be effected quickly. Other changes represent a significant departure from the existing reporting scheme and will require careful rule drafting to accomplish their purpose. Chesapeake sincerely thanks the Commission for this opportunity to comment on the disclosure system for our industry. We would be pleased to meet with the staff to share our technology expertise and advise on implementation issues. Please contact the undersigned at 405-879-9111 if we can help in any way.

Sincerely,

Steven C. Dixon
Executive Vice President Operations
Chief Operating Officer