General Request for Comment

As noted above, in light of the extent and pace of changes in the oil and gas industry and public concern that our oil and gas reserves disclosure requirements are not fully aligned with current industry practice, we are reconsidering our oil and gas reserves disclosure requirements. The Commission seeks public comment on our oil and gas reserves disclosure requirements and related issues.

Questions

1. Should we replace our rules-based current oil and gas reserves disclosure requirements, which identify in specific terms which disclosures are required and which are prohibited, with a principles-based rule? If yes, what primary disclosure principles should the Commission consider? If the Commission were to adopt a principles-based reserves disclosure framework, how could it affect disclosure quality, consistency and comparability? No comment

2. 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? Yes, allow probable and possible reserves as these are important as having a large inventory of future drilling locations is vital for future reserve replacement and production growth. In order to bring consistency and eliminate nomenclature differences use Society of Petroleum Engineers--Petroleum Resources Management System definitions. At the very least the SEC should allow the "best estimate" (2P) as an additional reserve disclosure.

3. 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? Adopt all of the Society of Petroleum Engineers--Petroleum Resources Management System.

4. Should we consider revising the current definition of proved reserves, proved developed reserves and proved undeveloped reserves? If so, how? Is there a way to revise the definition or the elements of the definition, to accommodate future technological innovations? Utilize the definitions and guidelines in the Society of Petroleum Engineers--Petroleum Resources Management System. The definitions and guidelines take into account modern technology. For example PUD locations are

5. Should we specify the tests companies must undertake to estimate reserves? If so, what tests should we require? Should we specify the data companies must produce to support reserves conclusions? If so, what data should we require? Should we specify the process a company must follow to assess that data in estimating its reserves? No, covered by Petroleum Resources Management System as follows: "In order to be considered as

proved reserves there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests

6. Should we reconsider the concept of reasonable certainty? If we were to replace it, what should we replace it with? How could that affect disclosure quality? Should we consider requiring companies to make certain assumptions? Should we prohibit others? Use Petroleum Resources Management System's certainty definitions.

7. Should we reconsider the concept of certainty with regard to proved undeveloped reserves? Should we allow companies to indefinitely classify undeveloped reserves as proved? Reasonable certainty should be the certainty used with regard to proved undeveloped reserves. The guidelines in Petroleum Resources Management System areas follows: The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive and interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. A limit should be set for proved undeveloped reserves to be initiated with 5 years recommended as a benchmark.

8. Should we reconsider the concept of economic producibility? If we were to replace it, what should we replace it with? How could that affect disclosure quality? Should we consider requiring companies to make certain assumptions? Should we prohibit others? Use Petroleum Resources Management System's commerciality criteria.

9. Should we reconsider the concept of existing operating conditions? If we were to replace it, what should we replace it with? How could that affect disclosure quality? Should we consider requiring companies to make certain assumptions? Should we prohibit others? Use Petroleum Resources Management System.

10. 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 use of standard prices, such as annual average prices or year-end prices, make the SEC evaluations more consistent and comparable among companies. The use of average prices may reduce volatility but year-end prices may be more representative of year-end values. The solution should require standardized selling prices and costs and allow additional reserve disclosures at different prices (sensitivity analyses). The sensitivities should be standardized as either +/- fixed %(i.e. +/- 20%) or change per unit (i.e. +/- $.50 in price) and present what that change means in reserves and value.

11. Should we consider eliminating any of the current exclusions from proved reserves? How could removing these exclusions affect disclosure quality? No comment

12. Should we consider eliminating any of the current exclusions from oil and gas activities? How could removing these exclusions affect disclosure quality? No comment

13. Should we consider eliminating the current restrictions on including oil and gas reserves from sources that require further processing, e.g., tar sands? If we were to eliminate the current restrictions, how should we consider a disclosure framework for those reserves? What physical form of those reserves should we consider in evaluating such a framework? Is there a way to establish a disclosure framework that accommodates unforeseen resource discoveries and processing methods? No comment

14. 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? No comment

15. Should we consider requiring companies to engage an independent third party to evaluate their reserves estimates in the filings they make with us? If yes, what should that party's role be? Should we specify who would qualify to perform this function? If so, who should be permitted to perform this function and what professional standards should they follow? Are there professional organizations that the Commission can look to set and enforce adherence to those standards? The preparation of reserves or audit or review by an independent third party would enhance the reliability, consistency and completeness of all companies' reserve reporting. Evaluation standards are being discussed and under development but at the very least the work at independent third party firms is done by or under the direction of professional engineers, geologists and geophysicists with their individual standards. The process is self correcting because if the SEC has problem with the reserves the firm will not stay in business.

In addition to the areas for comment identified above, we are interested in any other issues that commenters may wish to address and the benefits and costs relating to investors, issuers and other market participants of the possibility of revising disclosure rules pertaining to petroleum reserves included in Commission filings. Please be as specific as possible in your discussion and analysis of any additional issues. Where possible, please provide empirical data or observations to support or illustrate your comments.

The current staff interpretation that PUD locations must be immediately adjacent to producing units and their interpretation that certainty means absolute certainty for utilization of newer technologies such as 3-D seismic for PUD locations more than one offset away is outdated and not consistent with how companies make drilling decisions. For our major asset we have used our 3-D interpretation for the past 7 years drilling a mixture of PUD, probable, possible and even un-engineered locations with 100 % success in obtaining commercial wells. In addition the current interpretation is very difficult to apply to this same field which has 4 different well drilling densities with areas approved for 40, 20, 10 and 5 acre development. If PUD locations are booked as direct offsets to a 40 acre drilled producing well and the area is down spaced to 10 acres drilling do we lose PUD locations? Has the certainty been decreased for the other 3 locations in the booked 40 acre area?