RE: <u>File No. S7-29-07</u>

Concept release on possible revisions to the disclosure requirements relating to oil and gas reserves.

<u>Questions:</u>

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?**

<u>Response:</u> The current system appears to be both a rules based and principle based system. Many of the current rules or interpretations of the rules are actually staff interpretations of the original 1978 rules. The overall lack of clear guidance concerning reserves estimation and classification and exclusion of modern technology has led to inconsistencies in reserves reporting, quality of reserves estimates, and a wide variance of what is reported as proved by different companies, as well as inconsistency in domestic and international reporting.

The revised reporting system should include the following:

A. The increased use of modern technology in reserves estimation and reserves reporting. However, to be considered as acceptable proven technology, the practices utilized must be in widespread usage in the areas in which the reserves are located and have a demonstrated track record of repeatability and consistency. Look backs must demonstrate and confirm the validity of the technology. Each estimate and reserves classification based on or incorporating modern technology must be documented by the entities claiming the reserves.
B. Technology (which includes new mathematical concepts or manipulations) is considered to be unproven until there is a clear track record of industry acceptance and has been verified by actual well, reservoir, and/or field performance.
C. Reserves estimation and classification rules must be consistent for domestic and international properties and reservoirs.
D. Reserves estimation and classification rules must be consistent for both "conventional" and "unconventional" reservoirs.
E. The burden of proof for reserves classification shall remain consistent between "conventional" and "unconventional" reservoirs, and for mature and newly developing areas, but recognize that there may not be enough data to support a proven classification in frontier areas or newly developing areas early in the life of those areas. Each estimate must be documented and supported by the entities claiming those reserves.

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 should we consider? Should we specify categories of reserves? If so, how should we define those categories?**

Response: Reporting of only proved reserves does not provide the investing public with a representative value of a company's total worth. Private investors or other companies may be at a disadvantage during buy outs or mergers by providing information on non-proved reserves or resources to a subset of investors. The Commission should require reporting of proved reserves but allow reporting of probable and possible reserves under a strict set of rules and principles. Definitions with adequate disclosures concerning the risk of each reserve category should be included.

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?

Response: The SPE PRMS, released in March 2007, is a giant step forward in reserves and resources estimation and classification. It is a major overhaul of previous definitions and successfully outlines the vast majority of the problem areas in reserves and resources estimation, classification, documentation, and reporting.

The SPE has already recommended that the Commission adopt the PRMS in its entirety. **I do not agree with the position of the SPE.**

While the majority of the final PRMS product is very good and needs no alterations, some issues became products of compromise by committee with individuals, companies, and countries during the review and comment period. To a degree, the SPE allowed these groups to insert non-technical issues rather than remaining an advocate for the continued best use of technology, experience, and integrity in all instances.

I am a registered engineer in Texas and a 30+ year member of the SPE. I am currently one of the instructors for the SPE short course on Petroleum Reserves, which teaches the PRMS and SEC rules, regulations, interpretations, and reserves reporting compliance and documentation. I am also an instructor for Petroskills-OGCI and teach their course in Oil and Gas Reserves.

Prior to my retirement, I was a reservoir engineer employed by a major US oil company, 2 independent oil companies, and a consulting petroleum engineering firm which issues more independent SEC-compliant reserves reports than any other engineering firm in the world.

I have authored or co-authored numerous schools on SEC and SPE reserves reporting compliance. I also authored, co-authored, or edited the reserves policy manuals for both major and independent oil companies. Currently, I serve as an independent outside auditor on two major international companies' reserves audit committees.

I have seen "new" technology come and go and have personally observed both intentional and unintentional misinterpretation and misuse of data, application of incorrect technology, sloppy engineering and geologic work, and violations of SEC reserve definitions. I have observed how the intent of the present regulations has been manipulated to achieve corporate, national, or individual goals. I have also witnessed a widespread misunderstanding pertaining to how SEC rules should be interpreted.

It is my opinion that the new SPE PRMS should be the starting point for new SEC definitions, but it should be modified to close loopholes, reduce ambiguity, provide more detailed guidance in several areas, and remove both company and national agendas. Specifically, I find problems with the recommended pricing position, definitions of unproven reserves vs. resources, and certain incorporation of modern technology on a stand alone basis. The definitions should also be strengthened as to the definition of "net reserves" in international settings. This is one area of worldwide reporting inconsistency.

If the Commission adopts a modified PRMS and the PRMS changes, the Commission could again appoint an independent, unbiased review group headed by a recognized technical expert (such as Dr. Lee) to review the changes and recommend appropriate changes and modifications at that time.

I would consider it an honor and privilege to serve as a technical advisor to Dr. John Lee and the SEC staff engineers to revise, strengthen, implement, and document a new SEC reporting system, including definitions and guidance (with examples). My passion is for a technology-based set of clearly defined definitions, with integrity, ethics, documentation, and accountability being the cornerstones of that oil and gas reserves reporting system.

4. Should we consider revising the current definitions of proved reserves proved developed reserves and proved undeveloped reserves? Is there a way to revise the definition or the elements of the definition, to accommodate future technological innovations?

<u>Response:</u> A modification of the new PRMS definitions would not be materially different from the current SEC definitions of proved reserves, proved developed reserves, and proved undeveloped reserves. This could be easily accomplished. The rules would need regular, periodic review and updating. The rules may include currently utilized specific types of technology but still permit new proven technology to be incorporated as it develops (as outlined in the response to Question 1). Each reserves reporter bears the burden of proof. The Commission should regularly post new developments and staff guidelines on its website that is easily accessible.

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 reserves?

Response: The type, quality, and quantity of all data (including well production tests) required to estimate and classify reserves should be judged on the merits of each case individually. In any mature area or developing area with enough actual field examples, well logs (resistivity and porosity), sidewall and/or conventional cores, wireline formation tests, or actual production well tests, in conjunction with appropriate analogies to existing mature wells, reservoirs, or fields in the same immediate area, may or may not be sufficient for proof of proven reserves. In some cases, one of the above criteria, with appropriate analogies, may be sufficient; in other cases, all of the data may be required. The reporting company must document and produce data of sufficient quality, quantity, and similarity to existing commercial fields. This section could incorporate much of the 2001 SPE "Guidelines for the Evaluation of Petroleum Reserves and Resources" and the SPE "Standards Pertaining to the Estimating and Auditing of Petroleum Reserves Information".

Aside from verification well testing, the PRMS provides a nearly complete set of evaluation techniques. Clarification of those definitions and examples would be helpful.

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?

Response: The concept of reasonable certainty should be kept for deterministic reserves estimates. The new definitions or interpretative guidelines should be strengthened to better define how reasonable certainty is achieved and documented. It may be easier to regularly list elements or examples that do not meet the reasonable certainty test. Probabilistic estimates should be allowed under a strict set of criteria that includes no input parameters or output that exceed the observed values in the reservoir or field for which the estimate is being prepared. Appropriate analogies should be provided to support both deterministic and probabilistic estimates.

Adoption of a modified PRMS already includes numerous assumptions that are recommended or discouraged. One modification needs to be a better way to choose a common set of pricing guidelines for all reserves reporting. Perhaps an average of the previous 12 months historical prices by property or an SEC generated price forecast in November of each year would be appropriate. The PRMS' recommendation of every reporting company using its own forecast is not recommended. Very few companies, if any, will report a price forecast upon which that company actually makes decisions. The actual prices received during a previous 12-month period is a matter of record, and companies report average prices received during the previous year in financial reports. The usage of different price forecasts does not and will not level the investing playing field or promote transparency, or consistency.

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?

<u>Response:</u> The PRMS guidelines offer a good set of criteria to establish proved undeveloped reserves that are consistent with the SEC concept of reasonable certainty. The PRMS guidelines give adequate criteria that make it appropriate to assign undeveloped locations more that one offset location away.

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?

<u>Response:</u> Economic producibility should be retained as a criteria required to be classified as proved reserves. Economic limit should be defined as the point at which the monthly cash flow goes negative and stays negative. A short term negative is acceptable if the cost forward economics are positive, not counting any liability for existing abandonment obligations. Abandonment costs for new wells or projects must be included in the cash flow, and the project must be economic at the as of date of the report.

Obviously, the prices used in the report will have a major effect on economic limit. Again, using average wellhead prices, with adjustments for BTU, differentials, and transportation, should be a 12 month average or a price deck posted by the SEC. If using a 12 month average, a September to September may be representative and practical. The price should reflect the base price for the location of each field in the report along with the average differential for the same time frame. All companies should be required to use this 12 month average or an SEC provided price forecast. No companies should use their best estimate of future pricing conditions, as allowed in the PRMS.

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?

<u>Response:</u> The concept of existing operating conditions should be better defined and clarified with examples. Each company should evaluate the actual operating expenses for the previous 12 months and the previous 6 months. The average cost of the most representative period should then be applied. For example, a field may average 85M$ per month over the last year, but during the last 6 months expenses average 110M$ due to rising costs. The last six months should be chosen as most reflective if appropriate.

If a change in conditions is to occur, that change must be documented. Examples could include abandonment of a water injection program, removal of one platform in a multi-platform field, additional compression, etc. Costs should be reflected upward or downward for specific itemized events. Companies should reflect budgeted operating expense increases based on proven projects. Companies should not reduce the operating expenses unless the reduction is tied directly to an explicit and described change in operating conditions that is reasonably certain to occur.

Operating costs may be split into fixed and variable components. The variable components may be reflected in a variable $/well/month, $/MCF, $/BBL, processing fees, or other component that must be documented as to how the component is derived and why it is valid. The fixed component should reflect costs that are required to operate the field that are not dependent on well count, throughput, or other reoccurring operating expense. Companies should be prohibited from making all operating expenses dependent on a variable based on throughput, such as $/BBL or $/MCF, which will change as volumes drop. This is a major flaw in many current reports.

Companies should provide a written explanation of how the operating costs were determined.

<u>Third Party Processing Income</u>
If a company receives income from a third party for operating wells, platforms, fields, projects, or processing of third party gas, the company may reflect the income from those operations on a separate income page. The difficulty arises from making an estimate of the volumes and life of the third party products if the reporting company does not have an interest in the same properties. Perhaps a credit with a diminishing value could be incorporated. For example in year 1, 80% of the previous year's income, year 2 60%, year 3 40%, year 4 20%, and then no additional credits.

The company also should document what the third party processing costs and deduct that actual portion of the expenses from their operating expenses.

At no time does the reporting company book reserves for processing or transporting third party oil and gas.

10. Should we reconsider requiring companies to use a sale price in estimating reserves? 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 the disclosure quality and consistency? Regardless of he 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?

<u>Response:</u> The Commission should definitely reconsider revising the pricing policies and definitions. As previously stated, use of either a 12 month average or a price deck generated by the Commission and available no later than November 1 of each year. Using the average of September to September would allow companies to have the data captured and available. This data would include price differentials to the reference sales point, BTU and quality adjustments, or actual averages for local spot market for new projects. The prices used should be a historical average and not based on futures prices.

Under no circumstances should individual companies be allowed to generate their own price forecasts for the basic proven SEC reserves report. This is will lead to inconsistency, and no one will be able to compare companies.

Use of a single day price, as currently used, causes wild changes in reserves, such as the bitumen problem in 2004, or extension of marginal properties due to high year end, weather-related spiking.

Companies should be allowed to run, publish, and discuss the effects of price sensitivities but not required to do so. If published, the price assumptions must be clearly documented and state that they are not SEC compliant price assumptions.

Use of an average price or SEC generated price deck would lead to consistency between companies.

11. Should we consider eliminating any of the current exclusions from proved reserves? How could removing these exclusions affect disclosure quality?

Response: The PRMS does a good job including oil (natural or synthetic), gas, or plant products that are generated from either conventional or unconventional resources. The Commission should allow inclusion of oil or gas generated from coal, tar sands, oil shale, shale, or by any established extraction method so long as the project meets Commission economic standards and has a known and repeatable history.

The same criteria for commerciality, undeveloped classification, and certainty should apply to both conventional and unconventional resources.

The disclosure quality would be greatly improved by accounting for all hydrocarbon reserves.

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

Response: All activities and processes that result in the sale of oil, synthetic oil, natural gas, or plant products should be included. This would include upgraders for generation of synthetic crude oil, mining (if necessary to extract and produce the synthetic oil), and other extraction processes.

Transportation, refining, and marketing of consumer end use products should still be excluded. All activities up to the point of sale of the gas, oil, synthetic oil, or plant products would be deemed oil and gas activities.

The disclosure quality would be greatly improved by accounting for all hydrocarbon reserves.

Natural gas that is injected into a reservoir for pressure maintenance or improved recovery should be classified as reserves until it is sold if the gas was originally owned by the company injecting the natural gas. Gas purchased from a third party for injection would be considered as a storage project and not reserves.

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?

Response: See answer 12. The PRMS summarizes this topic well and should be adopted. Future changes should be accounted for by regular review between the Commission and outside sources such as the SPE or SPEE.

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?

Response: By adopting a modified SPE PRMS framework, the Commission could review and either incorporate or modify any updates or changes proposed by the SPE, AAPG, SPEE, or WPC. Again, any technology that has been field tested and has showed consistency and repeatability in a given area may qualify as acceptable technology. Each company bears the burden of proof to show that a technology should be accepted as proved in a given region.

15. Should we consider requiring companies to engage an independent third party to evaluate their reserve estimates in the filings they make to us? If yes, what should that third 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?

Response: The Commission should **not** require companies to engage an independent third party to evaluate or audit their reserves estimates unless that company has a 3 year track record of downward reserve revisions in excess of 10 % of that year's beginning reserves base, or if that company has been requested by the Commission in any year to make downward reserves revisions or write offs in excess of 20 % of that company's assets at the beginning of the year. These revisions or write-offs should be those that are not caused by sale of assets or by prices and economics. In the cases of negative reserves revisions, the Commission may or may not require that the company submit to a 3rd party evaluation or review of significant assets. If such an independent 3rd party evaluation is requested by the Commission, the Commission will approve the independent 3rd party, and that 3rd party may not have participated in the evaluation year or years in question. (This ensures that no 3rd party audits itself.)

Third party independent estimates should be encouraged in the form of:

1. Independent Reports
2. Audit of Company Properties
3. Inclusion of 3rd party in company internal audit teams

If a third party is employed at the option of the company, that employment must be disclosed and reported, even if the reporting party files their own estimates or chooses to not use any work by the third party. At the point at which an evaluation or audit is commenced, fields may not be deleted from the auditing process.

Standards for 3rd party evaluation or audit procedures are adequately presented in the SPE "Standards Pertaining to the Estimating and Auditing of Petroleum Reserves Information".

The SPE, SPEE, AAPG, and WPC have no regulatory capacity and no enforcement capabilities. The SEC or the US Congress should set up fines and penalties for willful violation, misrepresentation, destruction of data, willful omission of data, coercion, and other acts by the executives, management, and employees accountable for estimation of reserves in reporting companies and any 3rd party independent evaluator who commits such acts. Basically, there should be stern enforcement of provisions already in current laws for fraud and the Sarbanes-Oxley Act. One or two convictions would clean up the non-compliance faster than a comment letter.

<u>Other Topics for Consideration by the Commission:</u>

1. Consistency in how shrinkage is reported. The PRMS is a good model.
2. Consistency in how net reserves are estimated. The PRMS is a good start but needs more clarification.
3. A revision in how non-hydrocarbon gases are handled. The PRMS is a good model.

Thank you for the opportunity to submit these responses.

Sincerely,

Robert M. Wagner PE

SPE Co-instructor of Petroleum Reserves Short Course