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September 8, 2008

To: Florence E. Harmon
Acting Secretary
Securities and Exchange Commission
File Number S7-15-08
Comments on Proposed Modernization of the Oil and Gas Reporting Requirements

Dear Ms. Harmon:

We commend the Securities and Exchange Commission on the thorough review and analysis of the commentary received from the December 2007 Concept Release and for the open and transparent process for public input to the proposed revisions in the disclosure requirements for oil and gas reporting.

We appreciate this opportunity for comment and would welcome the opportunity to discuss our responses further with the Commission staff.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

John E. Hodgin

John E. Hodgin
President, P.G., P.E.

SECURITIES AND EXCHANGE COMMISSION 17 CFR Parts 210, 229, and 249

[Release Nos. 33-8935; 34-58030; File No. S7-15-08] RIN 3235-AK00

MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS

AGENCY: Securities and Exchange Commission. **ACTION:** Proposed rule.

II.B. Year-End Pricing

II.B.1. 12-month average price
Request for Comment
Should the economic producibility of a company's oil and gas reserves be based on a 12-month historical average price?

Yes. The use of a 12-month average historical price would dampen the volatility related to the current pricing regulations. The longer term view provided by a 12-month historical average would better represent the economic conditions impacting the determination of economic producibility for reserves reported by a company.

Should we consider an historical average price over a shorter period of time, such as three, six, or nine months?

No. The use of a twelve month period incorporates enough data to avoid significant, possibly short term changes for seasonality, supply or price speculation which create rapid price fluctuations. A shorter period may unfairly distort prices and not represent a changing or sustainable trend.

Should we consider a longer period of time, such as two years? If so, why?

No. The use of a two year average may fail to account for recent economic factors and their impact on prices and current price trends.

Should we require a different pricing method?

No.

Should we require the use of futures prices instead of historical prices?

No. Futures prices are subject to market perceptions rather than market reality. While futures prices are used in financial instruments such as hedges and swaps, etc, they are seldom used in actual physical trading of oil and gas volumes. For this reason, futures should not be used in SEC filings.

Is there enough information on futures prices and appropriate differentials for all products in all geographic areas to provide sufficient reporting consistency and comparability?

Information regarding certain futures prices such as those publicly reported on the NYMEX is readily available but is typically only referenced to Henry Hub, Louisiana for gas and to Cushing, Oklahoma for oil. However, information about product differentials is not as readily accessible and tends to vary as a function of price. Furthermore, gas prices in different geographical regions do not consistently compare to the prices at Henry Hub. For example, the prices for gas sold in the Rockies do not consistently relate to the gas price at the Henry Hub. As a result, the determination of product differentials based on a future price may lack the appropriate historical substantiation and would be based on each company's best estimate. This estimation process could lead to potentially significant inconsistencies among reporting companies.

Should the average price be calculated based on the prices on the last day of each month during the 12-month period, as proposed?

No.

Is there another method to calculate the price that would be more representative of the 12-month average, such as prices on the first day of each month?

Yes. A preferred method would be to use an arithmetical average of the daily prices for the entire 12-month period as the benchmark price used for the sale of products from any particular field. The average should be calculated on a field-by-field basis rather than a company wide basis. Obviously these benchmark average prices would need to be adjusted appropriately for quality, location and other considerations for the particular property.

Why would such a method be preferable?

This method would be preferable as it would more accurately represent the historical price actually paid for the sale of products, as opposed to a price based on an average of twelve one-day prices.

Should we require, rather than merely permit, disclosure based on several different pricing methods? If so, which different methods should we require?

A requirement for multiple scenarios would be the equivalent of a probabilistic approach with an emphasis on pricing cases. The results would cause confusion for investors and could result in unintended accounting issues that would require additional disclosure.

Should we require a different price, or supplemental disclosure, if circumstances indicate a consistent trend in prices, such as if prices at year-end are materially above or below the average price for that year? If so, should we specify the particular circumstances that would trigger such disclosure, such as a 10%, 20%, or 30% differential between the average price and the year-end price? If so, what circumstances should we specify?

In general, no. As noted, short term volatility in prices may not represent a true change in trend. Consideration should be given for optional voluntary supplemental price sensitivity if the filer is of the opinion that such short term fluctuations are material to near term cash flow and planned activity levels.

II.B.2. Trailing year-end

Request for Comment

Should the price used to determine the economic producibility of oil and gas reserves be based on a time period other than the fiscal year, as some commenters have suggested? If so, how would such pricing be useful?

Yes. The determination of reserves cannot be completed until the appropriate prices are known. Since evaluators must wait until year end until prices are known, this significantly compresses the timeframe to complete the reserves estimation process at year end and then provide this information to the accountants for incorporation into year end filings based on current SEC filing deadlines. Furthermore, certain accounting data lags behind and must be estimated at year end. If the final reported price to be used was known 3 months in advance, it would allow for both more time to adequately prepare the reserves and greater accuracy in year end reports.

Would the use of a pricing period other than the fiscal year be misleading to investors?

No. Each filer would use the same pricing period which would be disclosed by the company in their filing statement. The filings for each subsequent year would include the same period (for example using the historical pricing period between October 1, XXXX and September 30, XXXX) and achieve a consistent disclosure year-on-year.

Is a lag time between the close of the pricing period and the end of the company's fiscal year necessary? If so, should the pricing period close one month, two months, three months, or more before the end of the fiscal year? Explain why a particular lag time is preferable or necessary. Do accelerated filing deadlines for the periodic reports of larger companies justify using a pricing period ending before the fiscal year end?

Yes, a time lag based on a three month period would allow alignment on a quarterly basis.

II.B.3. Prices used for accounting purposes

Request for Comment

Should we require companies to use the same prices for accounting purposes as for disclosure outside of the financial statements?

Yes. The requirement for reserves to be prepared on two different pricing scenarios imposes a significant burden and would create undue confusion. Different price scenarios do not just impact the resulting cash flows. Changes in pricing impact the economic limits and thus the reserve volumes. Some undeveloped projects may be economic under one pricing scenario and not under another. Reconciliation between the two will impose a significant time burden on the process when the process is already under stress to meet year end reporting deadlines. The potential for differing reserve volumes under two different pricing scenarios would confuse most unsophisticated oil and gas investors that do not understand the direct relationship between economics and reserve volumes.

Is there a basis to continue to treat companies using the full cost accounting method differently from companies using the successful efforts accounting method? For example, should we require, or allow, a company using the successful efforts accounting method to use an average price but require companies using the full cost accounting method to use a single-day, year-end price?

No comment.

Should we require companies using the full cost accounting method to use a single-day, year-end price to calculate the limitation on capitalized costs under that accounting method, as proposed? If such a company were to use an average price and prices are higher than the average at year end or at the time the company issues its financial statements, should that company be required to record an impairment charge?

No comment.

Should the disclosures required by SFAS 69 be prepared based on different prices than the disclosures required by proposed Section 1200?

No comment.

If proved reserves, for purposes of disclosure outside of the financial statements, other than supplemental information provided pursuant to SFAS 69, are defined differently from reserves for purposes of determining depreciation, should we require disclosure of that fact, including quantification of the difference, if the effect on depreciation is material?

No comment.

What concerns would be raised by rules that require the use of different prices for accounting and disclosure purposes? For example, is it consistent to use an average price to estimate the amount of reserves, but then apply a single-day price to calculate the ceiling test under the full cost accounting method? Would companies have sufficient time to prepare separate reserves estimates for purposes of reserves disclosure on one hand, and calculation of depreciation on the other? Would such a requirement impose an unnecessary burden on companies?

No comment.

Will our proposed change to the definitions of proved reserves and proved developed reserves for accounting purposes have an impact on current depreciation amounts or net income and to what degree?

No comment.

If we change the definitions of proved reserves and proved developed reserves to use average pricing for accounting purposes, what would be the impact of that change on current depreciation amounts and on the ceiling test? Would the differences be significant?

No comment.

General Observation: If a single day year end price is retained for accounting purposes, that one day price would be subject to the same volatile system that presently results in wide variations in year end reserves estimates. To use differing prices for accounting and reserves reporting purposes would not appear to achieve the level of clear understanding and transparency desired by all users of SEC filing information.

II.C. Extraction of Bitumen and Other Non-Traditional Resources
Request for Comment
Should we consider the extraction of bitumen from oil sands, extraction of synthetic oil from oil shales, and production of natural gas and synthetic oil and gas from coalbeds to be considered oil and gas producing activities, as proposed?

Yes.

Are there other non-traditional resources whose extraction should be considered oil and gas producing activities? If so, why?

Since it is difficult to identify emerging technologies that may be successful in the future, the definition of "oil and gas producing activities" should embrace the SPE/WPC/AAPG/SPEE PRMS terminology of unconventional resources and emphasis should be based on the nature of the end product of such activities as proposed by the SEC.

The extraction of coal raises issues because it is most often used directly as mined fuel, although hydrocarbons can be extracted from it. As noted above, we propose to include the extraction of coalbed methane as an oil and gas producing activity. However, the actual mining of coal has traditionally been viewed as a mining activity. In most cases, extracted coal is used as feedstock for energy production rather than refined further to extract hydrocarbons. However, as technologies progress, certain processes to extract hydrocarbons from extracted coal, such as coal gasification, may become more prevalent. Applying rules to coal based on the ultimate use of the resource could lead to different disclosure and accounting implications for similar coal mining companies based solely on the coal's end use. How should we address these concerns? Should all coal extraction be considered an oil and gas producing activity? Should it all be considered mining activity? Should the treatment be based on the end use of the coal? Please provide a detailed explanation for your comments.

We note that the proposed SEC definition "would state specifically that oil and gas producing activities include the extraction of marketable hydrocarbons, in solid, liquid, or gaseous state, from oil sands, shale, coalbeds or other nonrenewable natural resources which can be upgraded into natural synthetic oil or gas, and activities undertaken with a view to such extraction." A logical extension of the definition would allow for the inclusion of coal extracted specifically for further refinement to extract marketable hydrocarbons if the final product at the point of transfer from the ownership to the buyer is oil, synthetic oil or a natural gas. However, the extraction of coal that has a transfer of ownership from owner to buyer on an as-is basis should be excluded as an oil and gas producing activity.

Again the emphasis is on the nature of the end product at the point of transfer of ownership to distinguish between an oil and gas producing activity and a mining, manufacturing and/or refining process.

Similar issues could arise regarding oil shales, although to a significantly less extent, because those resources currently are used as direct fuel only in limited applications. How should we treat the extraction of oil shales?

One difference between oil shales and coal is that coal can be used in its original form without further processing. Since oil shales must be processed into liquid or gaseous hydrocarbons, it is appropriate that its extraction be considered an oil and gas producing activity if the final product at the point of transfer from owner to buyer is a marketable hydrocarbon.

If adopted, how would the proposed changes affect the financial statements of producers of non-traditional resources and mining producers?

In our opinion, broadening the disclosure guidelines to fully encompass all oil and gas producing activities that result in marketable quantities of oil and/or gas under the agreed definition would add significantly to the oil and gas reserves for producers of unconventional resources. Such disclosure would more accurately reflect the companies' reserves as well as the country's reserves, benefiting not only investors but also strategic energy planners and the government in the management of domestic resources.

II.D. Reasonable Certainty and Proved Oil and Gas Reserves
<u>Request for Comment</u>
Is the proposed definition of "reasonable certainty" as "much more likely to be achieved than not" a clear standard? Is the standard in the proposed definition appropriate?

Since the proposed definition of reasonable certainty is generally understood within the industry at this time, it can be deemed a clear standard. The proposal to define the term reasonable certainty as "much more likely to be achieved than not" is consistent with the prior SEC guidance as noted in the March 31, 2001 website release: "The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision."

Would a different standard be more appropriate?

The introduction of the additional clarification to the defined term "reasonable certainty"; "the EUR is much more likely to increase than to either decrease or remain constant" imposes an additional constraint to the definition that implies a more stringent standard than the prior SEC guidance. We recommend the inclusion of clarifying guidance which states that <u>the EUR is much more likely to increase or remain constant than to decrease</u> which would be more aligned with the prior standards.

Is the proposed 90% threshold appropriate for defining reasonable certainty when probabilistic methods are used? Should we use another percentage value? If so, what value?

Yes. In our opinion, when probabilistic methods are used, there should be at least a 90% probability that the reserves quantities actually recovered will equal or exceed the estimate. The 90% threshold is appropriate for reasonable certainty as applied to proved reserves and should be reached at the reservoir level and not at a summary or portfolio level.

II.D.1. New technology
Request for Comment
Is our proposed definition of "reliable technology" appropriate? Should we change any of its proposed criteria, such as widespread acceptance, consistency, or 90% reliability?

The proposed definition of the term "reliable technology" is clear. However, it is not clear how one could unconditionally present empirical proof that a specific technology leads to the correct conclusions in 90% or more of its applications. As currently written, the term "correct conclusion" is more subjective than applying the constraints for reasonable certainty as the qualifying criteria comparing the outcome to the original estimate. Additionally, the requirement to summarize the proportion of reserves related to the use of a particular technology may be excessively burdensome and in certain instances could represent a concern regarding the disclosure of emerging technology and the loss of a competitive advantage. Upon request, as is presently the case, companies should be ready to provide the SEC compelling evidence supporting all evaluation techniques and the underlying technologies used in their reserve determinations.

Is the open-ended type of definition of "reliable technology" that we propose appropriate?

The proposed definition of "reliable technology" is appropriate.

Would permitting the company to determine which technologies to use to determine their reserves estimates be subject to abuse?

As noted, the burden of providing a compelling case for the application of any evaluation technique or technology rests on the reporting company.

Do investors have the capacity to distinguish whether a particular technology is reasonable for use in a particular situation?

In most cases, no.

What are the risks associated with adoption of such a definition?

Companies are clearly aware that they are subject to review by the SEC at any time through the comment letter process. The SEC has adequate enforcement powers to mitigate systematic instances of abuse should they arise.

Is the proposed disclosure of the technology used to establish the appropriate level of certainty for material properties in a company's first filing with the Commission and for material additions to reserves estimates in subsequent filings appropriate?

First, it is unclear what "first filing" means. Would this require a new registrant to disclose all technology while imposing no such burdens on existing registrants, or is the intent for disclosure referring to the first time reserves are booked for a particular well, reservoir or field? Is the intent for disclosure of new technology, if used, or for all technology? Either way, the requirement for disclosure of (new) technology would impose a significant burden on filers as previously noted. However, filers should be required to provide concise explanations including references to the application of any evaluation technique or technology in their disclosure statements for all material changes (either additions or reductions) in reserves.

Should we require disclosure of the technology used for all properties?

No as previously noted.

Should we require companies currently filing reports with the Commission to disclose the technology used to establish appropriate levels of certainty regarding their currently disclosed reserves estimates?

No. It is difficult to envision that investors have the knowledge to determine whether appropriate technologies are suitable for a given situation. Investors would be more likely to reward companies that tout the use of technologies improperly applied and penalize companies for not using inappropriate technology. While the use of new technology is within the capabilities of evaluators, the disclosure of technology imposes a significant burden on the process.

II.D.2. Probabilistic methods

Request for Comment

Are the proposed definitions of "deterministic estimate" and "probabilistic estimate" appropriate?

Yes

Should we revise either of these definitions in any way? If so, how?

The proposed definition of a "deterministic estimate" as presently written could be construed as having application only to static volumetric estimates. We note that reserves estimated using dynamic performance methods often rely on the use of a single most appropriate variable such as exponential decline rates, hyperbolic exponents and/or terminal limits not associated with economics to name a few. We suggest the following clarification to the definition of a "deterministic estimate" as being an estimate that is based on using a single "most appropriate" value for each variable used in the estimation of reserves whether using static volumetric or dynamic performance methods.

Are the statements regarding the use of deterministic and probabilistic estimates in the proposed definition of "reasonable certainty" appropriate? Should we change them in any way? If so, how?

We suggest a minor modification, as noted by the strikeout below, in the proposed definition of a "probabilistic estimate" as being an estimate that is obtained when the full range of values that could reasonably occur from each ~~unknown~~ parameter (from the geoscience, engineering, and economic data).... Values selected for each parameter used to derive a 90% probability should include only those values which have been observed to reasonably occur in the field or in the immediate area. The inclusion of unknown values implies an evaluator may include data by extrapolation beyond values that can be reasonably substantiated. One such example would be the extrapolation of a downdip hydrocarbon limit without supporting pressure or seismic evidence.

Should an oil and gas company have the choice of using deterministic or probabilistic methods for reserves estimation, or should we require one method?

Companies should have a choice of which method they choose to estimate reserves.

If we were to require a single method, which one should it be? Why? Would there be greater comparability between companies if only one method was used?

We do not advocate one method over the other; however, from practical experience, we find that estimates based on deterministic methods can be more readily verified for compliance to SEC reporting requirements. In that regard, we are of the opinion that it is more difficult to provide assurance that reserves estimated using probabilistic methods are compliant with all facets of the regulations. In general, many evaluators may lack the specialized training necessary to assure proper application of probabilistic methods to the evaluation of SEC compliant reserves.

Should we require companies to disclose whether they use deterministic or probabilistic methods for their reserves estimates?

In the spirit of transparency companies should provide full disclosure, noting if all of their estimates rely on either deterministic or probabilistic methodology or some combination of methodologies. In cases where a company uses a combination of methods, the disclosure statement should provide an explanation for the use of differing methodologies.

II.D.3. Other revisions related to proved oil and gas reserves

<u>Request for Comment</u>

Should we permit the use of technologies that do not provide direct information on fluid contacts to establish reservoir fluid contacts, provided that they meet the definition of "reliable technology," as proposed?

Yes, subject to the reservations expressed earlier regarding how companies could demonstrate reliability. Furthermore, the extrapolation of downdip hydrocarbon limits should be primarily but not solely based on pressure vs depth plots which include data points obtained from the same hydraulically continuous reservoir for both the hydrocarbon and water phases. Pressure data must be of sufficient quantity and quality to substantiate a unique continuous fluid gradient trend. Extrapolated downdip limits should not conflict with other subsurface geological or geophysical data such as downdip wet wells, seismic amplitude terminations or seismic flat spots. The use of well calibrated high resolution seismic data may also be considered subject to the constraints noted for a clear demonstration of reliability.

Should there be other requirements to establish that reserves are proved? For example, for a project to be reasonably certain of implementation, is it necessary for the issuer to demonstrate either that it will be able to finance the project from internal cash flow or that it has secured external financing?

Company management should be able to demonstrate assurance of their intent to proceed based on sanctioning at the appropriate level within the company and capability to finance the project based on approved internal budgets or business plans or firm commitments for external financing. The company should demonstrate commitment via a clear track record of project execution of similar projects in terms of timing, scope and/or expenditure. Furthermore, the company should be reasonably certain that approvals by partners and appropriate governmental regulatory agencies are in place or be reasonably certain of progressing.

II.E. Unproved Reserves—"Probable Reserves" and "Possible Reserves"

Request for Comment

Should we permit a company to disclose its probable or possible reserves, as proposed?

Yes.

If so, why?

The additional disclosure data will provide some additional insight to the broader portfolio of opportunities for the future company growth. Some investors will find this information to be important.

Should we require, rather than permit, disclosure of probable or possible reserves? If so why?

No.

Should we adopt the proposed definitions of probable reserves and possible reserves? Should we make any revisions to those proposed definitions? If so, how should we revise them?

The proposed definitions of probable and possible reserves are appropriate as they follow the PRMS definitions.

Are the proposed 50% and 10% probability thresholds appropriate for estimating probable and possible reserves quantities when a company uses probabilistic methods?

The proposed thresholds are appropriate as they follow those used in the PRMS definitions.

Should probable reserves have a 60% or 70% probability threshold? Should possible reserves have a 15% or 20% probability threshold? If not, how should we modify them?

We do not support the use of thresholds other than those used in the PRMS definitions.

II.F. Definition of "Proved Developed Oil and Gas Reserves"
Request for Comment
Should we revise the definition of proved developed oil and gas reserves, as proposed?

Yes.

Should we make any other revisions to that definition? If so, how should we revise it?

No.

II.G. Definition of "Proved Undeveloped Reserves"
II.G.1. Proposed replacement of certainty threshold
Request for Comment
Are the proposed revisions appropriate? Would the proposed expansion of the PUDs definition create potential for abuses?

We support the application of the common measure of reasonable certainty for both proved developed and undeveloped reserves. The burden of proof to establish a compelling case to support the proved area still rests with the evaluator and should be determined by the totality of all of the available engineering and geoscience data including seismic data and appropriately documented analogs. While we understand that the intent is to allow incorporation of all sources of information that could establish reasonable certainty of economic production, we believe that the phrase "at any distance from productive limits" as denoted in the proposed definition to "permit the use of evidence gathered from reliable technology that establishes reasonable certainty of economic producibility" could be misused without further qualification. For example, would that guidance allow for an evaluator to incorporate analogs evidence from beyond the generally accepted bounds of the subject reservoir in the field at hand to another producing basin elsewhere in the world? Furthermore, the additional clarifying language suggested to allow inclusion of actual drilling statistics "in the area" may be subject to misuse without further qualification for the subjective term "in the area".

Should we replace the current "certainty" threshold for reserves in drilling units beyond immediately adjacent drilling units with a "reasonable certainty" threshold as proposed?

Yes, noting the observations given above.

Is it appropriate to prohibit a company from assigning proved status to undrilled locations if the locations are not scheduled to be drilled more than five years, absent unusual circumstances, as proposed?

Yes, as a general guideline, given the option to include long lead time projects with appropriate disclosure. The use of the term "unusual circumstances" could be considered an unfair standard as many large development projects in their early stages of development (that may not be particularly complex projects in remote areas) often require more than 5 years to develop. We also note that the proposal by the SEC states that the new definition "would prohibit a company from assigning proved status to undrilled locations if a development plan has not been adopted indicating that the locations are scheduled to be drilled within five years, unless it disclose unusual circumstances…". The use of the term "developed plan…adopted" raises a question of documentation. In many cases, a field may not be required to have a regulatory or governmentally approved official development plan. Absent such an official development plan, there may exist only an approved budget for of some short duration for near-term activity and an internal longer term business plan which would support the company stated goal of fully developing the field. We suggest that the SEC clarify the criteria needed to support that a "development plan has been adopted" by the company. Although not specifically addressed, proved undeveloped reserves are often assigned for situations other than undrilled locations. In certain cases proved non-producing behind pipe zones are classified as proved undeveloped based on certain levels of future capital expenditures. Does the SEC intend to apply the same standard to these cases?

Should the proposed time period be shorter or longer than five years? Should it be three years? Should it be longer, such as seven or ten years?

Five years is reasonable since a longer time period can be used with sufficient justification and documentation.

Should the proposed definition specify the types of unusual circumstances that would justify a development schedule longer than five years for reserves that are classified as proved undeveloped reserves?

As proposed, the definition provides several generalized circumstances such as complex projects and remote locations. As it would be difficult to envision the various circumstances for inclusion in the definition, we support the requirement for the disclosing company to provide adequate justification of delays beyond the proposed five year period. Each situation should be viewed within its context and on a case by case basis.

II.G.2. Proposed definitions for continuous and conventional accumulations
Request for Comment

Should we provide separate definitions of conventional and continuous accumulations, as proposed?

The inclusion of separate definitions of conventional and continuous accumulations would be appropriate if the SEC opts to require disclosure related to the divisions of a company's reserves into these two types. The SEC preamble to the proposed definitions appears to suggest that proximity is an issue related to the determination of PUDs associated with the two different types of hydrocarbon accumulations. "The fundamental difficulty in making these estimates is calculating the volume of a resource beyond the immediate area in which wells have been drilled ... that should be included in the proved category". How does this guidance to segregate reserves by accumulation type relate to the proposed changes in the definition of proved undeveloped reserves?

Would separate disclosure of these accumulations be helpful to investors?

Certainly some investors may find the increase in disclosure detail to be helpful; however, we suggest that the SEC give consideration to weighing the benefits compared to the potentially burdensome task of providing separate estimates by accumulation type. Furthermore, in a limited number of cases both conventional and continuous accumulations exist within the same field resulting in an arbitrary allocation of the fixed cost of operations.

Should we revise our proposed definition of "continuous accumulations" in any way? For example, should the proposed definition provide examples of such accumulations? If so, how should we revise it?

The proposed definitions are adequate as they are aligned with the PRMS guidance. One suggestion would be to additionally note that continuous accumulations may be pervasive throughout large areas and have ill-defined boundaries but eventually are bounded by field limits determined by reservoir quality or economics.

Should we revise our proposed definition of "conventional accumulations" in any way? If so, how should we revise it?

The proposed definitions are adequate as they are aligned with the PRMS guidance. One suggestion would be to additionally note that conventional accumulations "typically" are bounded by a hydrocarbon-water contact but not in all situations such as fault bounded reservoirs or reservoirs that are limited by stratigraphic boundaries.

II.G.3. Proposed treatment of improved recovery projects

<u>Request for Comment</u>

Should we expand the definition of proved undeveloped reserves to permit the use of techniques that have been proven effective by actual production from projects in an analogous reservoir in the same geologic formation in the immediate area or by other evidence using reliable technology that establishes reasonable certainty?

Yes. We also suggest providing clear guidance to define what constitutes an appropriate analogue.

II.H. Proposed Definition of Reserves

<u>Request for Comment</u>

Is the proposed definition of "reserves" appropriate? Should we change it in any way? If so, how?

The definition of reserves should be aligned with PRMS. We suggest that consideration should be given to denote reserves are those sales volumes of marketable hydrocarbons measured and reported at the custody transfer point. We note the use of the phrase "economic producibility at current prices and costs". We suggest that the use of current prices and costs be clarified and in agreement with the final position on the period used to derive the hydrocarbon prices.

II.I. Other Proposed Definitions and Reorganization of Definitions
Request for Comment
Are these additional proposed definitions appropriate? Should we revise them in any way?

In general yes, subject to the suggested clarifications offered.

Are there other terms that we have used in the proposal that need to be defined? If so, which terms and how should we define them?

We note that evaluators would benefit from further clarification of the following terms used in the context of the proposed definitions:

- Same geological formation
- Immediate area
- Analog(ue)
- Productive unit
- Drilling unit

Should we alphabetize the definitions, as proposed?

Yes.

Would any undue confusion result from the re-ordering of existing definitions?

No.

III. Proposed Amendments to Codify the Oil and Gas Disclosure Requirements in Regulation S-K
Request for Comment
Is the proposed amendment to Instruction 3, limiting it to extractive activities other than oil and gas activities, appropriate? Should we simply call them mining activities?

No comment.

Are there any other aspects of Item 102 that we should revise? If so, what are they and how should they be revised?

No comment.

III.A. Proposed New Subpart 1200 to Regulation S-K Codifying Industry Guide 2 Regarding Disclosures by Companies Engaged in Oil and Gas Producing Activities

III.A.1. Overview

III.A.2. Proposed Item 1201 (General instructions to oil and gas industry-specific disclosures)

Request for Comment

Are the proposed general instructions to Subpart 1200 clear and appropriate? Are there any other general instructions that we should include in this proposed Item?

No comment.

For disclosure items requiring tabulated information, should we require companies to adhere to a specified tabular format, instead of permitting companies to reorganize, supplement, or combine the tables?

No comment.

In particular, should we permit a company to disclose reserves estimates from conventional accumulations in the same table as it discloses its reserves estimates from continuous accumulations?

No comment.

III.A.3. Proposed Item 1202 (Disclosure of reserves)

III.A.3.i.Oil and gas reserves tables

Request for Comment

Should we permit companies to disclose their probable reserves or possible reserves? Is the probable reserves category, the possible reserves category (or both categories) too uncertain to be included as disclosure in a company's public filings? Should we only permit disclosure of probable reserves? What are the advantages and disadvantages of permitting disclosure of probable and possible reserves, from the perspective of both an oil and gas company and an investor in an oil and gas company that chooses to provide such disclosure? Would investors be concerned by such disclosure? Would they understand the risks involved with probable or possible reserves? Would the proposed disclosure requirements provide sufficient disclosure for investors to understand how companies classified their reserves?

As previously noted, we support the optional disclosure of probable and/or possible reserves. We take no position on whether a company should be limited to the disclosure of just their probable reserves. We do advise the SEC to require that each filing contain an explanatory section which fully describes and defines the levels of uncertainty (as opposed to risk) associated with probable and/or possible reserves quantities. Furthermore, it is incumbent that the filing includes a clear statement and explanation of whether the PRMS deterministic incremental approach, the PRMS deterministic scenario approach or the PRMS probabilistic scenario approach underpins the reserves quantities presented in the filing. Absent a concise explanation, we are concerned that investors would not appreciate the difference between the incremental quantities of probable or possible reserves and the cumulative quantities represented as the 2P, 3P or P50 and P10 scenarios.

Should the proposed Item require more disclosure regarding the technologies used to establish certainty levels and assumptions made to determine the reserves estimates for each classification?

No as previously noted.

Should companies be required to provide risk factor disclosure regarding the relative uncertainty associated with the estimation of probable and possible reserves? Should we allow filers to report sums of proved and probable reserves or sums of proved, probable, and possible reserves? Or, to avoid misleading investors, should we allow only disclosure of each category of reserves by itself and not in sum with others, as proposed?

We believe that the appropriate classification of reserves based on the PRMS definitions addresses the differing levels of uncertainty between reserves categories. Adherence to the PRMS definitions would provide a framework for consistency and as a result, comparability between different filers reserves quantities. We are concerned about proposing to disclose risk factors or the inclusion of risk adjusted quantities as the determination of risk is highly subjective and would likely vary significantly between filers. It is our opinion that investors would be better informed by the inclusion of a written discussion of the key factors relating to the probability that the quantities will actually be recovered. We do not advise the addition of incremental quantities of reserves in different reserve categories and would prefer that disclosure be of each category by itself.

Should we require disclosure of probable or possible reserves estimates in a company's public filings if that company otherwise discloses such estimates outside of its filings?

We take no position on whether a company should be required to disclose their probable and possible reserves if they otherwise make public these estimates outside their filings.

Should we require all reported reserves to be simple arithmetic sums of all estimates, as proposed?

As noted, we do not advise the addition of incremental quantities of reserves in different reserve categories and would prefer that disclosure be of each category by itself.

Alternatively, should we allow probabilistic aggregation of reserves estimated probabilistically up to the company level? If we do so, will company reserves estimated and aggregated deterministically be comparable to company reserves estimated and aggregated probabilistically?

We note that under PRMS definitions, probabilistic aggregation of reserves is limited to the field, property or project level. Summarization at the company level should be based on arithmetic summation by reserves category. Significant differences may occur between the arithmetic summation and probabilistic aggregation of proved (1P) quantities as well as proved plus probable plus possible (3P) quantities of reserves and to a lesser degree with respect to proved plus probable (2P) quantities of reserves as noted in the PRMS publication. Investors may not be aware that the probabilistic aggregation of reserves could result in different estimated quantities than those from derived from the addition of deterministic estimates. Reserves for different fields, properties or projects estimated using differing methodologies (deterministic and probabilistic) then summarized at the company level would further distort comparisons to estimates based solely on one methodology. As a result, we suggest that all of a company's reserves be based on the application of a single methodology.

Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

We have observed that the oil and gas tables as proposed for inclusion in the filing segregate proved reserves into both the developed or undeveloped classifications and a resulting summary of total proved reserves; however, table entries for probable and possible are only noted as (total) probable and (total) possible. We suggest that the SEC clarify whether filers can include probable and possible reveres by classification or as total quantities only.

Should we eliminate the current exception regarding the disclosure of estimates of resources in the context of an acquisition, merger, or consolidation if the company previously provided those estimates to a person that is offering to acquire, merge, or consolidate with the company or otherwise to acquire the company's securities? If so, would this create a significant imbalance in the disclosures being made to the possible acquirer, as opposed to the company's shareholders?

No comment.

III.A.3.ii. Optional reserves sensitivity analysis table
<u>Request for Comments</u>

Should we adopt such an optional reserves sensitivity analysis table? Would such a table be beneficial to investors? Is such a table necessary or appropriate?

As previously noted the requirement for reserves to be prepared on different pricing scenarios imposes a significant burden and would create undue confusion. Different price scenarios do not just impact the resulting cash flows. Changes in pricing impact the economic limits and thus the reserve volumes. Some undeveloped projects may be economic under one pricing scenario and not under another. Reconciliation between the two will impose a significant time burden on the process when the process is already under stress to meet year-end reporting deadlines. The potential for differing reserve volumes under two different pricing scenarios would confuse oil and gas investors that do not understand the direct relationship between economics and reserve volumes.

Should we require a sensitivity analysis if there has been a significant decline in prices at the end of the year? If so, should we specify a certain percentage decline that would trigger such disclosure? Should we revise the proposed form and content of the table? If so, how should we revise the table's form or content?

As previously noted we do not believe that disclosure of alternate pricing scenarios should be a requirement. Consideration should be given for optional voluntary supplemental price sensitivity if the filer is of the opinion that such short term fluctuations are material to near term cash flow and planned activity levels.

As noted above in this release, SFAS 69 currently uses single-day, year-end prices to estimate reserves, while the reserves estimates in the proposed tables would be based on 12-month average year-end prices. If the FASB elects not to change its SFAS 69 disclosures to be based on 12-month average year-end prices, should we require reconciliation between the proposed Item 1202 disclosures and the SFAS 69 disclosures? What other means should we adopt to promote comparability between these disclosures?

We are of the opinion that disclosures under the proposed Item 1202 and disclosures under SFAS 69 should be aligned by using the same pricing scheme. Using differing prices is likely to result in differing reserves quantities. The resulting variance in reserves would only serve to confuse investors and other potential users of this information. In the event that SFAS 69 elects not to adopt the 12-month average year-end prices, then it is our opinion that the proposed change in prices should not be adopted by the SEC.

III.A.3.iii. Geographic specificity with respect to reserves disclosures
Request for Comment

We take no position regarding the questions raised in this section.

III.A.3.iv. Separate disclosure of conventional and continuous accumulations

We take no position regarding the questions raised in this section.

III.A.3.v. Preparation of reserves estimates or reserves audits
Request for Comments

Should we require companies to disclose whether the person primarily responsible for preparing reserves estimates or conducting reserves audits meets the specified qualification standards, as proposed? Should we, instead, simply require companies to disclose such a person's qualifications?

We believe that the individual or individuals who have the primary responsibility for the oversight of the reserves process including both the preparation of the company's reserves estimates as well as the reviewing and/or auditing of those reserves estimates should be appropriately qualified. We are of the opinion that qualifications adopted and published by the Society of Petroleum Engineers (SPE) contain the minimum standards to be met in this regard and should be adhered to by the parties who are charged with these responsibilities on behalf of the company. In those cases where it may not be practical to disclose the identity of all of the individuals involved, we support the inclusion of an attestation by the appropriate qualified individual who has the primary responsibility for reporting the company's reserves acknowledging that the company's reserves were prepared, reviewed and/or audited by individuals who meet the SPE standards.

Should we require disclosure regarding a person's objectivity when a company prepares its reserves estimates in-house? Should the proposed disclosures regarding objectivity be required only if a company hires a third party to prepare its reserve estimates or conduct a reserves audit, as proposed?

Article IV of the SPE "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" sets forth standards of independence, objectivity and confidentiality for reserves estimators and reserves auditors whether they are employees of the company or independent third party consultants. We do not see the need to require different disclosure requirements as both in-house and third party professionals should be held to the same standards. As noted above, we support the inclusion of an attestation acknowledging that the qualifications of the individuals involved meet the SPE standards set forth in this regard.

If a company prepares its reserves estimates in-house, should we require disclosure of any procedures that the company has taken to preserve that person's objectivity? Should we require disclosure of whether the internal person meets specified objectivity criteria? For example, should we apply the some of the same criteria that we propose to apply to third party preparers? If so, which ones?

We are of the opinion that a company would benefit from disclosing the procedures that have been taken to preserve objectivity of the responsible personnel. In our opinion, in-house personnel should be held to the same set of criteria for objectivity as proposed for third party preparers. We support the disclosure of the standards for objectivity for a company's in-house employees.

Consistent with the SPE's auditing guidance regarding internal auditors, should we require companies to disclose whether that person (1) is assigned to an internal-audit group which is (a) accountable to senior level management or the board of directors of the company and (b) separate and independent from the operating and investment decision making process of the company and (2) is granted complete and unrestricted freedom to report, to one or more principal executives or the board of directors, any substantive or procedural irregularities of which that person becomes aware?

Yes.

Should we require disclosure with other specific independence or objectivity standards and, if so, what?

We are of the opinion that adherence to and disclosure of the aforementioned standards is sufficient.

Should we revise any of the proposed provisions regarding a person's objectivity or technical qualifications? Should the proposal require disclosure of other criteria that would have bearing on determining whether the person is objective or qualified?

We are of the opinion that adherence to and disclosure of the aforementioned standards is sufficient.

Should a company be required to present risk factor disclosure if its reserves estimates were not prepared by a person meeting the objectivity and technical qualifications?

We believe that a company's personnel should be required to adhere to the aforementioned standards for objectivity and technical experience and expertise eliminating the need for other types of disclosures.

Because of the inherent uncertainty regarding estimates of probable and possible reserves, should we require the proposed disclosure only if a company chooses to disclose probable or possible reserves?

The aforementioned standards apply and should be upheld regardless of the reserve category reported.

Should we require that a third party prepare reserves estimates or conduct a reserves audit if a company chooses to disclose probable or possible reserves estimates?

No.

Should we require the proposed disclosure only if the company is using technologies other than those which are allowed in our current definitions to establish levels of certainty?

No.

III.A.3.vi. Contents of third party preparer and reserves audit reports
<u>Request for Comment</u>
Should we require a company to file reports from third party reserves preparers and reserves auditors containing the proposed disclosure when the company represents that a third party prepared its reserves estimates or conducted a reserves audit?

We support the inclusion of the report "letter" (referred to by the SEC as simply the "report") as an exhibit to a company's filing. As noted by the SEC, this report would encompass the specific descriptive and summary level information requested by the SEC in the preamble to this section. We also concur with the SEC's proposal not to include the "full reserves report" which would include detailed data at a property, field and/or well level.

As an alternative, should we not require that the third party's report be filed, but that the company must provide a description of the third party's report? If so, should we specify that the company's description of the third party's report should contain the information that we propose to require in the third party's report?

We believe that the inclusion of the third party's report is more appropriate than the company's description as both the report and the description should contain identical information. Furthermore, the report from the third party would include the attestation of the third party acknowledging that the company's reserves were prepared or audited by individuals who meet the SPE standards.

Should we specify the disclosures that need to be included in third party reports? If so, is the disclosure that we have proposed for the reserves estimate preparer's and reserves auditor's reports appropriate? Should these reports contain more or less information? If they should include more information, what other information should they include? If less, what proposed information is not necessary?

We concur that the SEC should specify the disclosures that need to be included in the third party's report. We are of the opinion that the disclosure requirements and the information proposed for the reserves estimate preparer's reports are also appropriate for the reserves auditor's reports. The information contained therein should be the same for both in-house and third party reports.

In an audit, should we specify the minimum percentage of reserves that should be examined and determined to be reasonable? If so, what should that percentage be? Should it be 50%, 75%, 90% or some other percentage? If so, why?

Article II of the SPE "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" states that a reserves report for the entity where entity is defined as a corporation, joint venture, partnership, trust, individual, principality, agency, or other person should be comprised of at least 80% of the entity's reserves, future production, and/or revenues. Article II does not specifically denote what proportion of an entity's reserves, future production, and/or revenues should be audited but rather that a reserves audit "should be of sufficient rigor to determine the appropriate reserves classification for all reserves in the property set evaluated". We are of the opinion that any percentage may be selected by the company for an audit. The percentage selected for inclusion in the audit should be disclosed as part of the report.

If the company engages multiple third parties to conduct reserves audits on different portions of its reserves, should the definition of reserves audit be conditioned on each third party evaluating at least 80% of the reserves covered by its reserves audit, as proposed? Is the scope of a reserves audit defined by geographic areas? If so, should the definition of a reserves audit be based on the third party's evaluation of 80% of the

reserves located in the geographic areas covered by the reserves audit?

As noted above, we are of the opinion that any percentage may be selected by the company for an audit including audits conducted by multiple third parties. There may be any number of reasons that a company may chose to define the scope of each third parties' assignment by geographical area, but we are not of the opinion that it is necessary that a third party audit any set percentage of a geographic area in order to validate the results of a third party's report. The percentage selected for inclusion in the audit by each of the third parties should be disclosed as part of the report.

Would disclosure that a company has hired a third party to audit only a portion of its reserves be confusing to investors?

In our opinion, no.

Is there a danger that investors will not be able to ascertain the extent of the reserves audit? Should we require that a company could not disclose that it has conducted a reserves audit unless 80% of all of its reserves have been evaluated by a third party or, if the company hires multiple third parties, by all of the third parties collectively?

As proposed, each third party that conducted a reserves audit of any portion of the company should be required to submit a copy of their report for inclusion in the filing. In doing so, the investors would have a clear understanding of the extent of the work performed by each third party as part of that audit.

Is the proposed definition of "reserves audit" appropriate? Should we revise this proposed definition in any way?

The proposed definition is appropriate as it follows the definition stated in the aforementioned SPE standards.

III.A.3.vii. Solicitation of comments on process reviews

<u>Request for Comment</u>

Should we require disclosure of whether a company has conducted a process review?

We are of the opinion that disclosure of whether a company has conducted a process review should be optional.

Notwithstanding the relative lack of rigor of a process review compared to a reserves audit, would investors find such information useful?

Clearly some investors would find such information useful; however, we cannot speak on behalf of all investors.

The proposal does not prohibit disclosure of process reviews. Is there a danger that the public may be confused by such disclosure?

Each company must make the decision as to the value gained by such a disclosure. Should the company elect to disclose that a process review was conducted; the disclosure should contain the appropriate third party report containing much of the same clarifying information as presented in the reserves or audit report.

Should we prohibit disclosure of any type of reserves-related activity other than the preparation of the reserves estimates or a reserves audit?

While we take no position regarding the disclosure of other types of reserves-related activities, we do note that the aforementioned SPE standards do denote a property reserves report "may contain reserves information limited to one or more reservoirs, fields, and or/projects." We do not speculate on the value gained by a disclosure at the reservoir, field or project size.

III.A.4. Proposed Item 1203 (Proved undeveloped reserves)
<u>Request for Comment</u>
Should we adopt the proposed table?

While we take no position on what information should be required for inclusion in a filing, we offer the following observations:

- The proposed table does not provide insight into the number of proved undeveloped locations and the proved reserves attributed to these locations which were scheduled by the company to be drilled that year. Nor does the proposed table compare the number of scheduled proved undeveloped locations and the proved reserves associated with those locations that were actually converted to proved developed reserves that year. Information of this nature would allow the user of the filing to compare projected plans to actual results.
- From the information shown in the proposed table, it is unclear whether the company is required to report the proved undeveloped reserves as booked for the fiscal year shown or the proved undeveloped reserves attributable to that fiscal year's drilling program. If the intent is to provide disclosure of the proved undeveloped reserves as booked for the fiscal year shown, we note that the proved undeveloped reserves shown as converted to proved developed may not necessarily be for the same locations as were scheduled for drilling that year.
- If the proposed table is intended to depict proved undeveloped reserves attributable to a fiscal year's drilling program, would it be necessary to provide the reconciliation relative to the table in the prior year's filing?
- From the dates 2004-2008 shown in the example table, it would appear that the information to be provided is for historical results rather than disclosing forward looking information that may be of similar or greater interest to users of this information.

Alternatively, should we simply require companies to reclassify their PUDs after five years?

If, as proposed, the SEC prohibits a company from assigning proved status to undrilled locations if those locations are not scheduled to be drilled for more than five years, absent unusual circumstance; then yes, a company would need to reclassify their PUDs after five years if they have not been drilled. However, as previously proposed by the SEC, certain exceptions based on unusual circumstances may apply to the five year limitation which would preclude companies from reclassifying PUDs after five years. The proposal to reclassify PUDs which were scheduled to be drilled but have not, should be on a case-by-case basis with the provision that a company may be able to appropriately document not reclassifying certain PUDs.

Should the table require disclosure of other categories of changes to the status of PUDs, such as acquisitions, removals, and production? Should we add any categories?

As noted above, we take no position on what information should be required for inclusion in a filing but would suggest that the SEC weigh the benefits to users of the filing and caution against requests for disclosure of information that are unduly burdensome to the company.

Some of the abuse related to PUD disclosure may be related to companies' desire to show proved reserves in light of our prohibition on disclosure of probable reserves. Would the proposed rules permitting disclosure of probable reserves reduce the incentive to categorize reserves as PUDs? If so, is the proposed table necessary?

We express no opinion as to the impact of the proposed rules permitting disclosure of probable reserves in relation to a company's desire to categorize reserves as PUDs.

Should we require disclosure of the reasons for maintaining PUDs that have been classified as PUDs for more than five years, as proposed? If not, why not?

While we take no position on what information should be required for inclusion in a filing, each company should be in position to provide support for maintaining PUDs that have been classified as PUDs for more than five years.

Should we require a company to disclose its plans to develop PUDs and to further develop proved oil and gas reserves, as proposed? If not, why not?

While we take no position on what information should be required for inclusion in a filing, each company should be in position to provide support for its plans to develop PUDS and further develop its oil and gas reserves.

Should we require the company to discuss any material changes to PUDs that are disclosed in the table? If not, why not?

While we take no position on what information should be required for inclusion in a filing, each company should be in position to provide clear and concise explanations for any material changes to their PUDs and/or plans to further develop their oil and gas reserves.

III.A.5. Proposed Item 1204 (Oil and gas production)
Request for Comments
Should we adopt the proposed table?

We take no position on what information should be required for inclusion in a filing.

Should the disclosure be made based on the proposed definition of "geographic area," or should we continue to follow the definition set forth in SFAS 69?

While we take no position on what information should be required for inclusion in a filing, we do suggest that the criteria for reporting of production be compatible with the criteria for reporting of the company's reserves.

Should we eliminate the instructions listed above, as proposed? If not, which instructions should we retain? Please explain why those instructions continue to be useful.

While we take no position on what information should be required for inclusion in a filing, we note the SEC proposes to eliminate certain of the existing instructions to Item 3 of Industry Guide 2 as "being no longer necessary as commonly understood in light of changes in the oil and gas industry". Two topics as listed in the preamble attributed to Item 3 of Industry Guide 2, namely the separate reporting of production through processing plant ownership and inclusion of only marketable production of gas on an "as sold" basis, including the exclusion of flared gas, injected gas and gas consumed in operations are topics which in our opinion still require some appropriate form of written guidance by the SEC regarding their inclusion as proved reserves under the proposed changes in SEC regulations.

III.A.6. Proposed Item 1205 (Drilling and other exploratory and development activities)
Request for Comment

No comment.

III.A.7. Proposed Item 1206 (Present activities)
Request for Comment

No comment.

III.A.8. Proposed Item 1207 (Delivery commitments)
Request for Comment

No comment.

III.A.9. Proposed Item 1208 (Oil and gas properties, wells, operations, and acreage)
Request for Comment

No comment.

III.A.10. Proposed Item 1209 (Discussion and analysis for registrants engaged in oil and gas activities)
Request for Comment

No comment.

VIII. Proposed Implementation Date
Request for Comment
Should we provide a delayed compliance date, as proposed above? If so, is the proposed date appropriate?

We suggest that the compliance date selected by the SEC give appropriate consideration to the date that the SEC Commission adopts the final set of oil and gas disclosure requirements and a harmonization occurs with SFAS 69. As we are unaware of the timeframe necessary for the aforementioned integration of the final regulations, we are unable to opine on the proposed date.

Should we provide more or less time for companies to familiarize themselves with the proposed amendments?

We firmly believe that it is in the best interest of the SEC, the companies, the investors and other users and preparers of this information that more lead time be allowed to efficiently and accurately prepare the initial filings under the new regulations.

If we provide a delayed compliance date, should we permit early adoption by companies?

We concur with the position of the SEC prohibiting early adoption by some companies as this would not facilitate ready comparison of disclosures from company to company.

IX. General Request for Comment

We are of the opinion that the proposed changes represent significant enhancement to the SEC regulations governing the disclosure of oil and gas information. Given the breadth of the proposed revisions, the proposal for swift implementation and the historical issues around industry's desire to better understand the application of the requirements to assure compliance to the regulations we suggest the following:

- The SEC should consider conducting a series of public presentations with question and answer periods which would review and clarify the new regulations similar to those provided by the Society of Petroleum Engineers regarding the adoption of the Petroleum Resources Management System. The primary intent of these presentations is the dissemination of factual data to the public.
- The SEC should consider participation in public forums such as those arranged by the Society of Professional Evaluation Engineers to allow the public to engage the SEC regarding areas of interpretation of the new regulations.
- The SEC should consider the opportunity to clarify interpretation of the regulations through a series of topical questions and interpretive responses similar to those presented in Topic 12 of Accounting Series Release 257. The questions could be initiated in several different ways and from different parties. First, the SEC could originate the questions based on the SEC's observations of areas of common non-compliance derived from the comment letter process between the SEC and companies. Secondly, the questions could be initiated by one or more of the professional societies representing the industry. Thirdly, the questions could be initiated by any interested party or by a combination of any of the aforementioned groups.
- The SEC could chose to convey clarifying information in a manner similar to the content of the March 31, 2001 website release.

It has been our observation that some parties involved in the estimation process encounter difficulties in the application of the SEC regulations due to the lack of clarity for applying the requirements to actual case-by-case issues. We are of the opinion that the parties involved in the reserves process could provide better assurance to the compliance of their evaluations with a more open and transparent venue in which to engage the SEC for clarification of the regulations. In regards to the application of the new regulations, we hope that the SEC will give their role of educating and informing all parties due consideration.