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Ms. Florence E. Harmon
Acting Secretary
Securities and Exchange Commission
100 F Street, NE
Washington, D.C. 20549-1090

September 8, 2008

RE: File No. S7-15-08, *MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS*

Dear Ms. Harmon,

We appreciate the opportunity to respond to the Securities and Exchange Commission's ("SEC") Proposing Release on Modernization of the Oil and Gas Reporting Requirements. We wish to commend the SEC for undertaking such an extensive and important project. Among the major enhancements proposed are: the ability to use reliable technology in determining proved reserves; the recognition that oil and gas reserves should be treated similarly whether they are obtained from conventional or unconventional sources, such as oil sands; the change from use of a single day price to an 12-month average price; and the recognition that current technology can provide reasonable certainty beyond the one well offset rule. If adopted, those four proposed changes, by themselves, would provide a major improvement to current standards that were established in the late 1970s. Investors and industry alike would obtain significant benefits. The Commission, however, has proposed other changes that also should receive serious consideration. This letter, however, suggests a few changes to the proposals that, we believe, would significantly reduce costs or increase the overall benefits associated with Commission's proposed changes. In addition, we have attached an appendix to our letter that addresses 140 of the Commission's specific requests for comment.

12-month average price should be used for both proved reserve disclosure and accounting purposes.

The Commission has proposed calculating proved reserves on two different bases. We believe this should be avoided at all costs. In this regard, we are unaware of any other area where the SEC has required empirical disclosure inconsistent with a company's financial statements. This proposal would result in less transparency and likely create investor confusion surrounding the proved reserve data and financial results, especially in years where the average price is significantly different than the December 31 closing price. Moreover, the cost associated with keeping two sets of books would be significant. We strongly recommend that the accounting and disclosure requirements be aligned. To this end, we also strongly suggest that the SEC proactively engage with the Financial Accounting Standard Board (FASB) as soon as possible to align their disclosure requirements.

There should be a 3-month lag in the calculation of the 12-Month average price.

The proposed rule changes would permit the use of an average price for the 12-month prior to the end of the company's fiscal year. We believe the 12-month average price is preferable to the use of the year-end price, as it would eliminate single day volatility, and therefore, be more reflective of "current economic conditions." However, we are concerned that use of 12-month average price that includes the price on the last day of the company's fiscal year would continue to require a recalculation of proved reserves data after year-end. This would occur since an estimate of the 12-month average price would have to be used in any evaluation of proved reserves done immediately prior to year-end. By using a 12-month average ending on the last day of a company third fiscal quarter, significant work can be completed prior to year-end and would not have to be re-done after year-end. Alternatively, the Commission could consider allowing the use of a 12-month average price based on the first day of each month. This would provide an additional 30 days to our year-end quality assurance process.

The Commission should clarify that proprietary technology can meet the "Reliable technology" definition.

While we fully support the Commission proposal to allow the use of "Reliable technology" in estimating proved reserves, we are concerned that the proposed definition would unwisely exclude the use of certain "Reliable technology" in the future. We are concerned that the "widely accepted" requirement would eliminate a company's ability to use its proprietary technology. We do not see that such a requirement is necessary provided that the technology used "has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation." By defining "Reliable technology" as only technology that is "widely accepted within the oil and gas industry" the Commission would be creating a disincentive for future development of technology, since such technology would only be useful if it was widely available to its competitors.

If the Commission, however, chooses to maintain the "widely accepted within the oil and gas industry" requirement, we request that the Commission clarify that it applies only to the general technology used and not the specific application. For example, a widely accepted technology would be a dynamic reservoir simulation not the specific vendor program that provides such simulation. If the Commission were to apply the "widely accepted" requirement to specific applications, such a requirement could have the adverse effect of providing monopolistic power to certain vendors' programs, while at the same time eliminating incentives for research and development of new technology.

The Commissions proposed definition of "Reliable technology" also requires the technology to have been "proved empirically to lead to correct conclusion in 90% or more of its applications." We believe the 90% requirement would be extremely difficult to verify and prove on an ongoing basis. Also it is likely to be prohibitively expensive, as it would require a continuous global assessment of any technology used in determining proved reserves. We believe if a company can demonstrate to the SEC that a specific technology "has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation" then it should deemed to be a "Reliable Technology."

The Commission's proposed definition of "Proved undeveloped reserves" should not include a five-year limitation.

The proposed definition of Proved undeveloped reserves (PUDs) requires a company to have adopted a development plan for its PUDs that indicates that such PUDs are scheduled to be drilled within five years, unless unusual circumstances justify a longer time. We believe this qualification is unnecessary. We believe that if the Reasonable Certainty criteria are met (including corporate commitment to develop and produce), then by definition, it is reasonable to expect that these PUDS will ultimately be profitably produced. In today's environment, many PUDs may not be drilled within a five-year period for reasons that are not necessarily unusual. For example, it is becoming much more common for companies to undertake "mega-projects" which can require more than five years, after project sanction, to initially develop the project. Additionally, as the demand for energy continues to increase, projects to extract difficult resources such as coalbed methane gas, tight gas, oil shales, and oil sands will be vital in meeting the US energy needs. These vital resources would be placed at a significant disadvantage; as such projects are often complex and can take longer than five years to develop. This significant disadvantage could lead to the under development of these critical resources to the detriment of US consumers. In addition, this would limit the estimate of US petroleum reserves as captured by the DOE-EIA, which relies on proved reserves reporting.

Finally, it should be noted that in all cases, the development and production of the reserves is fully committed and properly scheduled (and may be contractually bound as a supply to a buyer, as is common with a Liquefied Natural Gas project). Therefore, there is significant assurance that these PUDs will ultimately be developed. Companies will choose development schedules that are the most profitable to the company and thus the most beneficial to shareholders. We believe for shareholders to be able to properly evaluate a company's oil and gas prospects they should have disclosure of all proved reserves that meet the Reasonably Certainty definition. By removing the disclosure of certain PUDs from Commission filings we believe shareholders would be placed at a significant disadvantage from the current rules, as a portion of the true PUDs with reasonable certainty, would not be disclosed.

As an alternative to defining PUDs as those reserves to be developed within five years, the Commission could require disclosure of the percentage of PUDs, on an aggregate basis, expected to be developed within five years. We believe this would provide additional disclosure to investors without removing material information about a company's proved reserves.

The Commission should revise the Instruction to proposed definition of "Analogous formation in the immediate area" to clarify that in the aggregate the Reservoir properties are no more favorable in the analogue than in the formation of interest. The Commission should also permit the use of analogous formation outside the immediate area.

In the Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance of March 31, 2001, the staff stated:

"An analogous reservoir is one having at least the same values or better for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations."

This guidance has limited the use of analogues , as it would reject any analogue where there is an immaterial difference in one of the above categories. We believe that proper evaluation of an analogue should examine the above categories in the "aggregate" as opposed to individually, where there may be immaterial differences, when determining whether the analogous reservoir conditions are no more favorable than in the formation of interest. We believe this position is similar to a comparison of properties when used for improved recovery. In this regard we note the supported language of the proposed definition of Proved Oil and Gas Reserves (Proposed Rule 4-10(a)(24)(iv)(A)):

"Successful testing by a pilot project in an area of the reservoir with properties ***no more favorable than in the reservoir as a whole****, the operation of an installed program in the reservoir or analogous formation in the immediate area, or other evidence using reliable technology establishes the reasonable certainty of engineering analysis on which the project or program was based."*
(**Emphasis added**)

We believe the most appropriate comparison of reservoir properties, in the instance of a pilot project or for the use of an analogous formation, is best measured "as a whole" or in the aggregate rather than individually. This would be consistent in how these parameters interact in the physical world, as these parameters appear together in the determination of producibility, drainage distance and recovery. We also believe that restricting the use of analogous formations to the immediate area is unnecessary, provided that the analogous formation reservoir properties are in aggregate no more favourable than in the formation of interest.

The Commission should clarify the impact of Rule 12b-20 on the voluntary disclosure of probable and possible reserves. Are there situations where disclosure of probable or possible reserves could be mandatory under US Securities Laws?

Currently, disclosure of probable and possible reserves is prohibited in Commission filings. Accordingly, companies, generally, do not evaluate whether this information could be considered material in light of existing disclosure pursuant to Rule 12b-20 since they are prohibited from disclosing such information in their Commission filings. While we are grateful that the Commission has proposed in Instruction 2 to paragraph (a)(2) of Item 1202 of Regulation S-K that disclosure of probable or possible reserves is "permitted, but not required," we are nonetheless concerned that there may be certain situations where the staff may require such disclosure pursuant to Rule 12b-20. Disclosure of probable or possible reserves, especially in the detail format proposed, raises not only liability concerns, given the imprecise nature of the estimate, but also in certain situations could result in competitive harm to the company. We suggest that the Commission revise Instruction 2 to clarify that Rule 12b-20 does not apply to disclosure of probable or possible reserves due to the imprecise nature of the estimate. The Commission should also consider clarifying that if a company decides to provide disclosure of its probable or possible reserves, the company is not required to follow the format provided in Item 1202 for proved reserves. Additionally, given the significant uncertainty associated with these estimates, the Commission should consider amending Rule 175(b)(2)(ii) and Rule 3b-6(b)(2)(ii) to expand the safe harbor to include any probable and possible reserves estimates disclosed.

The Commission should include in the definitions section of proposed Rule 4-10 the definition of "Proven (Measured) Reserves," as it appears in Guide 7, as applicable to oil and gas reserves that are mined.

We fully support the Commission proposal to include as oil and gas producing activities the extraction of marketable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds or other nonrenewable natural resources, which can be upgraded into natural or synthetic oil or gas and activities undertaken with a view to such extraction. We believe, however, that the Commission should clarify what definition should be used for determining when mined oil and gas reserves are to be considered proved. We believe the current definition of "Proven (Measured) Reserves" in Guide 7 is appropriate. The Commission should also consider amending Guide 7 to provide clarity that when an issuer is engaged in significant mining activities and those mining activities are also considered oil and gas producing activities subject to the disclosure requirements of proposed Item 1200 of Regulation S-K, no additional disclosure would be required pursuant to Guide 7.

The Commission should reconsider the significant increase in non-material disclosure proposed by the Proposing Release.

As discussed in specific detail in the Appendix to this letter, the Commission proposals would require a significant increase in non-material disclosure. For example, the proposal would require companies to disclose all technologies used to classify reserves, significantly increase the detail of disclosure regarding geographic and properties at immaterial levels, require audit and assurance disclosures and conventional v. continuous accumulation disclosures that are unlikely to be considered material by investors. Furthermore, much of the additional proposed disclosure is not currently captured or used by management. Accordingly, there would be significant costs associated with the gathering and disclosing this information. Our Form 20-F for the fiscal year-ending December 31, 2007, was in excess of 200 pages. The proposed additional disclosure would significantly increase the length of our Form 20-F, almost certainly obscuring material information. In most cases, the proposed additional disclosure could be at best described as mosaic information. We urge the Commission to reconsider the additional disclosure requirements, as we believe it would very likely obscure the material information contained in our Form 20-F.

Finally, we wish to express our general support for the August 20, 2008, comment letter from the American Petroleum Institute.

We again would like to thank the Commission for undertaking such a significant and important project. We appreciate the opportunity to express our views on the Commission's proposal. If you have any questions, please contact either Joe Babits at +31 70 377 4215, Bob Deere at +31 70 377 4646 or me at +31 70 377 3120.

Sincerely,

Roy Waight
Executive Vice President Controller

Appendix

Response to Specific SEC Questions

"Modernization of the Oil and Gas Reporting Requirements"

12-month average price

1. ***Should the economic producibility of a company's oil and gas reserves be based on a 12-month historical average price? Should we consider an historical average price over a shorter period of time, such as three, six, or nine months? Should we consider a longer period of time, such as two years? If so, why?***

Yes, we support use of a 12-month historical average price.

2. ***Should we require a different pricing method? Should we require the use of futures prices instead of historical prices? Is there enough information on futures prices and appropriate differentials for all products in all geographic areas to provide sufficient reporting consistency and comparability?***

No, only 12-month historical average price should be used.

3. ***Should the average price be calculated based on the prices on the last day of each month during the 12-month period, as proposed? 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? Why would such a method be preferable?***

No, last day of the month average should not be used. Petroleum commodity traders will, on occasion, "clear their books" at month end to close their accounts. This has the potential to create an artificial movement in the market that may not be consistent with the true market for petroleum seen in the other days of that month. We recommend using the first day of the month to determine the 12-month average to avoid the "last day bias". Also use of first day pricing for the average would also provide most of December for companies to use the known average price in determining the economic elements of Proved reserves, thereby avoiding the rush to complete complex economic calculations as discussed in our response to questions 6 and 7.

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

No, you should not require disclosure based on several different pricing methods. While companies should be permitted to provide such disclosure if they believe it to be material to investors, we do not believe such disclosure is likely to be material.

5. ***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?***

No, you do not need to require such disclosure, as trend disclosure, if material, is already required by Management Discussion and Analysis requirements.

Trailing year-end

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

Yes. It is our preference to have a "lag period" in determining this price. This is useful to allow proper time for price impact calculations on reserves. Such calculations can be very complex for certain economic interest situations like production-sharing agreements. As discussed in our letter, we are concerned that use of 12-month average price that includes the price on the last day of the company's fiscal year would continue to require a recalculation of proved reserves data after year-end. This would occur since the estimates of the final 12-month average would have to be used during the proved reserves determination work done immediately prior to year-end. By using a 12-month average ending on the last day of a company third fiscal quarter, significant work can be completed prior to year-end and would not have to be re-done after year-end. Given the majority of a company's proved reserves are not likely to be produced in the coming year, the additional cost associated of using 12-month average price that includes the last day of company fiscal year, in our opinion, exceeds the benefits of using a slightly earlier date in one's estimate of proved reserves. However, if a "lag period" were not provided, the Commission should consider allowing the use of the first day of the month in calculating the 12-month average price to provide industry with more time needed to perform the calculations. Please see our response to question 7.

7. ***Is a lag time between the close of the pricing period and the end of the 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?***

We would suggest using a 3-month lag (prior year 4th quarter through reporting year quarters 1st through 3rd). This aligns economic calculations with the technical calculations, which typically occur during the 4th quarter. The current timing creates a peak workload for the limited staff with the expertise for these calculations.

Prices used for accounting purposes

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

The Commission has proposed calculating proved reserves on two different bases. We believe this should be avoided at all costs. In this regard, we are unaware of any other area where the SEC has required empirical disclosure inconsistent with a company's financial statements. This proposal would result in less transparency and likely create investor confusion surrounding the proved reserve data and financial results, especially in years where the average price is significantly different than the December 31 closing price. Moreover, the cost associated with keeping two sets of books would be significant. We strongly recommend that the accounting and disclosure requirements be aligned. To this end, we also strongly suggest that the SEC proactively engage with the Financial Accounting Standard Board (FASB) as soon as possible to align their accounting and disclosure requirements.

9. ***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?

Although the Company utilizes the success efforts accounting method, we recommend that use of an average price is appropriate and should be consistent for all companies regardless of the basis of accounting used.

10. ***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?***

Although the Company utilizes the success efforts accounting method, we recommend that the pricing parameters for impairment testing should be same under either accounting method.

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

There should be no difference with respect to the prices required by SFAS 69 and the proposed Section 1200. Please see our response to question 8.

12. ***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?***

Proved reserves, for purposes of disclosure outside the financial statements and for purposes of determining depreciation, should be defined consistently. Please see our response to question 8.

13. ***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?***

Inconsistencies with respect to different prices used for accounting and disclosure purposes will place unnecessary burdens upon companies and confuse investors with the creation of these multiple estimates. Please see our response to question 8.

14. ***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?***

Achieving consistency between the SEC and the applicable accounting standards with respect to reserve definitions is paramount. If the definitions are aligned, there will be an impact upon depreciation and net income. However, we are unable to assess the degree of the impact at this time within the limited response time period. A great deal of technical work would be required to re-assess the prior year technical and economic conditions, including the addition of unconventionals.

15. ***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?***

The impact to the ceiling test is not applicable as it relates to the full cost accounting method. The impact of depreciation regarding proposed changes is addressed directly above in our response to question 14.

Extraction of Bitumen and Other Non-Traditional Resources

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

Yes, we support this proposal. We believe a non-traditional mineral resource that is extracted to produce oil or gas, should be included in oil and gas reserves regardless of the method used to extract the mineral resource.

17. ***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.***

If coal is used to produce petroleum using an in-situ process, then the resulting volumes should be included in oil and gas reserves. Even when the mining extraction of coal is followed by further processing that produces a petroleum product, we believe petroleum from mined coal also should be included in oil and gas reserves to ensure all petroleum resources are recognised by this measure.

18. ***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?***

Oil shales that are used to produce petroleum using an in-situ process should be allowed to have resulting volumes included in oil and gas reserves. Likewise, mined oil shale used to produce petroleum should also be allowed to have resulting volumes included as reserves.

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

Not applicable.

Reasonable Certainty and Proved Oil and Gas Reserves

20. 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? Would a different standard be more appropriate?

The standard of reasonable certainty is appropriate. However the proposed definition appears to contain an inconsistency. The deterministic method is not allowed to report an exactly correct value, if known, as the proposed definition requires a deliberate understatement of reserves since the reported value must be "much more likely to increase than to either decrease or remain constant." The exact answer will remain constant. The probabilistic method, however, can yield a stated volume that is allowed to be "equal" to the actually recovered quantity. It is recommended that the phrase "or remain constant" either be removed from the definition or be moved in the wording to become "...is either much more likely to increase or remain constant than to decrease". Additionally, the previous guidance on reasonable certainty contained in ***Division of Corporation Finance: Frequently Requested Accounting and Financial Reporting Interpretations and Guidance of March 31, 2001***, applied only to technical data not to economic data. The concept of "much more likely to increase" should not apply to economic data, as it would suggest that a company should discount or manipulate the economic data so that in the future its reserves position would increase despite a negative change in the economic data which the company has no control over nor any specific ability to predict, such as a decrease in year-end prices or escalation of costs driven by pressures outside industry control.

21. 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, use of 90% probability to define "reasonable certainty" is an industry standard.

New technology

22. 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 requirement of "widely accepted within the oil and gas industry" would seem to eliminate the use of company proprietary technologies. This undermines the value returned to the investor from the research to develop such technologies. This criterion is unnecessary as the proprietary technology must meet the clear standard of "reliable" as defined by other elements of the definition. It is recommended the phrase "widely accepted within the oil and gas industry" be removed. If the Commission, however, chooses to maintain the "widely accepted within the oil and gas industry" requirement, we request that the Commission clarify that it applies only to the general technology used and not the specific application. For example, a widely accepted technology would be a dynamic reservoir simulation not the specific vendor program that provides such simulation. If the Commission were to apply the "widely accepted" requirement to specific applications, such a requirement could have the adverse effect of providing monopolistic power to certain vendors' programs, while at the same time eliminating incentives for research and development of new technology.

The Commissions proposed definition of "Reliable technology" also requires the technology to have been "proved empirically to lead to correct conclusion in 90% or more of its applications." We believe the 90% requirement would be extremely difficult to verify and prove on an ongoing basis. Also it is likely to be prohibitively expensive, as it would require a continuous global assessment of any technology used in determining proved reserves. We believe if a company can demonstrate to the SEC that a specific technology "has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation" then it should deemed to be a "Reliable Technology."

23. ***Is the open-ended type of definition of "reliable technology" that we propose appropriate? Would permitting the company to determine which technologies to use to determine their reserves estimates be subject to abuse? Do investors have the capacity to distinguish whether a particular technology is reasonable for use in a particular situation? What are the risks associated with adoption of such a definition?***

The proposed definition is appropriate and would not lead to abuse. The definition is not "open-ended" but rather fixed to the only critical measure, that of "demonstrated consistency and repeatability" in providing "correct conclusions". The fact we cannot today exactly define the specific technologies that may be the standard of the future should not deter the promulgation of a timeless rule. Investors have already granted their companies high faith in using technologies "reasonable...in a particular situation" through investment decisions in new projects costing billions of dollars that are based on analyses using those technologies. It seems likely the investor would want recognition of the resulting reserve volumes from such technology-supported decisions.

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

While we generally object to the cumulative impact of the proposed increase in disclosure, a general description of such technologies would be acceptable.

Probabilistic methods

25. ***Are the proposed definitions of "deterministic estimate" and "probabilistic estimate" appropriate? Should we revise either of these definitions in any way? If so, how?***

These definitions are appropriate with one revision or clarification. The proposed definitions now list "economic data" among the parameters that are either fixed at a single value (deterministic) or defined as a range (probabilistic). It is unclear what options exist to consider economic factors as a range. Does this mean probabilistic methods can use price and cost ranges? Perhaps the prices are fixed (12-month average) but product differentials (quality, location) can be expressed as a range? Please clarify if only fixed single historical values can be used in defining "existing economic conditions" (in which case "economic data" should be removed from the list of variable parameters) or what elements of economics are allowed to be expressed as ranges in a probabilistic calculation.

26. ***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?***

Please see our response to question 20.

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

The proper selection of method is often situation and timing specific rather than specific to one company. That is, certain field situations (e.g., simple structure and recovery mechanism vs. complex structure with uncertain recovery mechanisms) and field-life timing (e.g., initial development vs. late-life established performance) often drive the choice of method. Companies should have the option to use either method based on their assessment of which is proper. In all cases, the resulting reserves must meet the same standard of reasonable certainty.

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

No. We believe both methods are acceptable for determining reserve volumes that meet the criterion of reasonable certainty. Accordingly, such disclosure would be immaterial to investors.

Other revisions related to proved oil and gas reserves

29. 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, if the technology meets the proposed "reliable technology", we do not believe it is necessary for that technology to provide direct information on fluid contacts.

30. 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?

Proved reserves must be reasonably certain -- both in the capacity of the field to deliver the volumes and in the commitment and capacity of the company to develop and produce the volumes. However, we believe a proven track record of securing funding for implementation of company commitments is sufficient evidence. We do not support a requirement for secured external funding in cases where this track record has been shown.

Unproved Reserves — "Probable Reserves" and "Possible Reserves"

31. Should we permit a company to disclose its probable or possible reserves, as proposed? If so, why?

While we have no objection to the Commission permitting the disclosure of probable and possible reserves, we believe the Commission should clarify whether it believes there are situations where such disclosure would be considered mandatory. Currently, disclosure of probable and possible reserves is prohibited in Commission filings. Accordingly, companies, generally, do not evaluate whether this information could be considered material in light of existing disclosure pursuant to Rule 12b-20, since they are prohibited from disclosing such information in their Commission filings. While we are grateful that the Commission has proposed in Instruction 2 to paragraph (a)(2) of Item 1202 of Regulation S-K that disclosure of probable or possible reserves is "permitted, but not required," we are nonetheless concerned that there may be certain situations where the staff may require such disclosure pursuant to Rule 12b-20. Disclosure of probable or possible reserves, especially in the detail format proposed, raises not only liability concerns, given the imprecise nature of the estimate, but also in certain situations could result in competitive harm to the company. We suggest that the

Commission revise Instruction 2 to clarify that Rule 12b-20 does not apply to disclosure of probable or possible reserves due to the imprecise nature of the estimate. The Commission should also consider clarifying that if a company decides to provide disclosure of its probable or possible reserves, the company is not required to follow the format provided in Item 1202 for proved reserves. Companies may be more likely to provide these estimates in the aggregate as opposed to specific country, region or field level. Additionally, the Commission should consider amending Rule 175(b)(2)(ii) and Rule 3b-6(b)(2)(ii) to provide a safe harbor for probable and possible reserves estimates.

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

No, due to the imprecise nature and inherent inconsistency of these estimates among companies, we do not believe such estimates should be required to be disclosed. As discussed in our response to question 31, the Commission should indicated whether it believes there are situations where such information would be required to be disclosed, notwithstanding the proposed rule.

33. 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 definitions of probable and possible reserves should be those of the SPE/WPC/AAPG/SPEE in their Petroleum Resources Management System as this is the accepted industry standard.

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

The thresholds of probable and possible reserves should be those of the SPE/WPC/AAPG/SPEE in their Petroleum Resources Management System as this is the accepted industry standard.

Definition

35. Should we revise the definition of proved developed oil and gas reserves, as proposed? Should we make any other revisions to that definition? If so, how should we revise it?

Yes, the proposed definition is appropriate. No other revisions are needed.

Definition

Proposed replacement of certainty threshold

36. Are the proposed revisions appropriate? Would the proposed expansion of the PUDs definition create potential for abuses?

It is appropriate to revise the prior "certainty" criteria for some PUDs to the single standard for all Proved reserves of "reasonable certainty". We believe, the revised definition is appropriate with two revisions: (1) remove the 5 year timing limit (see our response to question 38 below); and (2) the proposed definitions continue to use the largely undefined (outside the onshore USA and Canada) terms, "drilling unit" and "productive unit". With so little of the currently reported reserves tied to regulatory spaced units, it seems inappropriate to use such terms for worldwide reserve determinations. These terms should be replaced or explained with clear definitions that have application globally.

37. ***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, please see our response to question 36.

38. ***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? 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?***

The proposed definition of Proved undeveloped reserves (PUDs) requires a company to have adopted a development plan for its proved undeveloped reserves that indicates that such PUDs are scheduled to be drilled within five years, unless unusual circumstances justify a longer time. We believe this qualification is unnecessary. We believe that if the Reasonable Certainty criteria are met (including corporate commitment to develop and produce), then by definition, it is reasonable to expect that these PUDS will ultimately be profitably produced. In today's environment, many PUDs may not be drilled within five-year period for reasons that are not necessarily unusual. For example, it is becoming much more common for companies to undertake "mega-projects" which can require more than five years, after project sanction, to initially develop the project. In all cases, the development and production of the reserves is fully committed and properly scheduled (and may be contractually bound as a supply to a buyer, as is common with a Liquefied Natural Gas project). Also some fields are in difficult locations and may take more time to develop. In some cases, availability of capacity in downstream assets may result in a slower development schedule. Companies will choose development schedules that are the most profitable to the company and thus the most beneficial to shareholders. We believe for shareholders to be able to properly evaluate a company's oil and gas prospects they should have disclosure or all proved reserves that meet the Reasonably Certainty standard. By removing the disclosure of certain PUDs from Commission filings we believe shareholders would be placed at a significant disadvantage from the current rules. As an alternative to defining PUDs as those reserves to be developed within five years, the Commission could require disclosure of the percentage of PUDs, on an aggregate basis, expected to be developed within five years. We believe this would provide additional disclosure to investors without removing material information about a company's proved reserves.

39. ***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?***

Please see our response to question 38.

Proposed definitions for continuous and conventional accumulations

40. ***Should we provide separate definitions of conventional and continuous accumulations, as proposed? Would separate disclosure of these accumulations be helpful to investors?***

As currently proposed, these definitions do not provide a useful distinction between materially different types of petroleum recovery activities. We do not believe such disclosure would be meaningful or material to investors. An alternative of using definitions for traditional oil and gas producing activities and non-traditional recovery methods (i.e., mining and manufacturing of petroleum) for separate disclosure would be more useful. We believe, however, by providing separate disclosure of these reserves, the Commission rules will be suggesting to investors that one type of reserves is more valuable than another. We strongly believe this not to be the case. The value of a specific reserve is much more dependent upon the production sharing agreement, royalties and taxes to be paid than whether the oil is mined or produced through conventional methods.

41. 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?

As noted above in our response to question 40, this distinction is not helpful and is very difficult to clearly define.

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

As noted above in our response to question 40, this distinction is not helpful and is very difficult to clearly define.

Proposed treatment of improved recovery projects

43. 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, the criteria for improved recovery reserves should be the same as all proved reserves, reasonable certainty established by reliable technology.

Proposed - Definition of Reserves

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

This definition should be clarified as to the required status of development project approvals. The conditions of "legal right to produce" and "appropriate level of certainty" (reasonable for proved) for permits, etc. make it seem that legal access to the property and company commitment to execute along with reasonable certainty of other approvals (e.g., regulatory) are sufficient. Yet in the improved recovery definition it is clearly stated that project approvals by all necessary parties and entities, including governmental entities are required. Generally, approvals occur at different stages of projects. Not all approvals are received prior to the commencement of a project. Accordingly, in most cases it would be difficult if not impossible to meet this requirement. Required project approvals should be the same for either improved recovery or any other type of oil and gas producing project. Please clarify.

Additionally, the reference to "legal right to produce" would seem to support the continued intent to disclose reserves in projects where the company may not legally own production (thus, reserves) but does have an "economic interest" and "participates in the operation of the related properties or otherwise serves as producer of the underlying reserves". If it is intended that this proposal limits disclosure to only those reserves in which the company has ownership of physical volumes, this should be clarified and further comments sought. We would object to such a limitation.

Other Proposed Definitions and Reorganization of Definitions

45. Are these additional proposed definitions appropriate? Should we revise them in any way?

Yes, they are appropriate with these further revisions. The definition for "analogous formation" should be clarified as to what standard is intended for "reservoir properties...no more favorable in the analogue than in the formation of interest". The definition in improved recovery for a pilot states "properties no more favorable in the reservoir as a whole". This seems to suggest the analogy comparison is to be done on reservoir properties in an effective aggregate ("as a whole") rather than on a specific, individual property basis. We find such an "aggregate properties" definition fully consistent with the principle of "reasonable certainty" and with industry standards (e.g., SPE PRMS). We fully support this approach as the effective elements of analogue comparisons always occur in an aggregated manner in the formulae used in Fluid Flow through porous media, evaluation of recoveries, evaluation of drainage areas, etc. For example, in transmissibility (the product of permeability and net thickness divided by viscosity), in the hydraulic diffusivity factor (Permeability divided by the product of porosity, viscosity and compressibility), in Mobility (permeability divided by viscosity), in Darcy's Law, in the solutions to the Diffusivity equation for different pressure regimes, in pressure transient analysis, in the estimation of radius of investigation, in the estimation of water influx, etc.

Also, the definition of condensate should specify the surface conditions to be those of the condensate as sold (i.e., commercial delivery conditions).

46. 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?

Yes, see our response to question 36 on the terms "drilling unit" and "productive unit". These have no meaning outside of a regulatory spaced unit situation. If these terms remain in a general definition, they need to be defined for non-regulatory use.

Additionally, we believe, that the Commission should clarify what definition should be used for determining when mined oil and gas reserves are to be considered proved. We believe the current definition of "Proven (Measured) Reserves" in Guide 7 is appropriate. The Commission should also consider amending Guide 7 to provide clarity that when an issuer is engaged in significant mining activities and those mining activities are also considered oil and gas-producing activities subject to proposed Item 1200 disclosure, no additional disclosure would be required pursuant to Guide 7.

47. Should we alphabetize the definitions, as proposed? Would any undue confusion result from the re-ordering of existing definitions?

Yes, alphabetical order is appropriate.

Proposed - Amendments to Codify the Oil and Gas Disclosure Requirements in Regulation S-K

Revisions to Item 102, 801, and 802 of Regulation S-K

48. 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?

The proposed definition appears appropriate; however, please see our response to question 46.

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

No, but please see our response to question 46.

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

Overview

Proposed Item 1201 (General instructions to oil and gas industry-specific disclosures)

50. ***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?***

The proposed general instructions are clear. We are concerned, however, that significant competitive harm could arise as a result of disclosing reserves at field level, while adding little value to investors.

51. ***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. It is suggested and preferred that the SEC provide guidance on what data are required leaving the flexibility of meeting these SEC "minimum standards" to the reporting company. This allows the company to have the option to design tables that more effectively communicate the material information to investors.

52. ***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?***

The distinctions between accumulation types are not needed or useful, as noted above in our response to question 40. Thus, such reporting should always be aggregated.

Proposed Item 1202 (Disclosure of reserves)

Oil and gas reserves tables

53. ***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?***

Please see our response to question 31.

54. ***Would the proposed disclosure requirements provide sufficient disclosure for investors to understand how companies classified their reserves? 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?***

Please see our response to question 24.

55. ***Should companies be required to provide risk factor disclosure regarding the relative uncertainty associated with the estimation of probable and possible reserves?***

Please see our response to question 31. Risk factor disclosure may be appropriate in certain situations but it should not be required.

56. ***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?***

Aggregate reporting may be appropriate and should be permitted provided the components are identified.

57. ***Should we require disclosure of probable or possible reserves estimates in a company's estimates outside of its filings?***

No. Please see our response to question 31.

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

Arithmetic sums should be used for all aggregation above the individual field level. Aggregation at the field level or below can be arithmetic sums, if deterministic methods are used, or probabilistic aggregation, if probabilistic methods are used.

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

Please see our response to question 51.

60. ***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?***

You should not eliminate the current exception.

Optional reserves sensitivity analysis table

61. 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?

No. A large percentage of companies proved reserves are produced over a number of years, thus a sensitivity analysis of any given year-end or 12-month average price would be of little value, since most of the reserves will not be produced in the coming year. Furthermore, we do not believe this disclosure would be material to an investor.

62. 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?

No, please see our response to question 61.

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

Yes, eliminate the table and its content.

64. As noted above in this release, SFAS 69 currently uses single-day, yearend 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?

The use of average prices to estimate proved reserves, for purposes of disclosures outside the financial statements and for purposes of SFAS 69 disclosures, should be applied consistently. Please see our response to question 8.

Geographic specificity with respect to reserves disclosures

65. Should we provide the proposed guidance about the level of specificity required when a company discloses its oil and gas reserves by "geographic area"?

No, please see our response to question 50. We believe the company is in the best position to decide what level of geographic reporting is appropriate.

66. Are the proposed 15% and 10% thresholds appropriate? Should either, or both, of these percentages be different? For example, should both be 15%? Should both be 10%? Would 5% or 20% be a more appropriate threshold for either or both?

With regard to disclosure on a country basis, we believe, the proposal is a reasonable approach. However, this could raise issues where a host country regards these data as sensitive, where there are laws governing the access to that information and disclosure of data from that country outside its borders. Any disclosure has to abide by the laws of that country. With regard to field level disclosure, we believe, such disclosure could result in significant competitive harm, while providing little values to investors. The amount of proved reserves associated with a specific field would provide investors with little value in evaluating those reserves since specific engineering and geological data would not be available to the investor. Additional, non-engineering risk is not normally associated at field level but rather at country level.

67. ***What would be the impact to investors if companies are permitted to omit disclosures based on the individual field or basin due to concerns related to competitive sensitivities? Would investors be harmed if disclosure based on the individual field or basin is omitted due to concerns related to competitive sensitivities? Is there a better way to provide disclosure that a company heavily dependent on a particular field or basin may be subject to risks related to the concentration of its reserves?***

We see no negative impact on investors. This information is currently not disclosed nor are we aware of any negative impact to investors. As noted in our responses to questions 50 and 66, this type of disclosure could result in serious competitive harm.

68. ***Would greater specificity cause competitive harm? Is so, how can the rules mitigate the risk of harm?***

Yes. Please see our responses to questions 50 and 66.

69. ***In the event that the FASB does not amend SFAS 69, should we require companies to supplement their SFAS 69 disclosure with greater geographic specificity? If the FASB does not amend SFAS 69, should we require that companies reconcile the differences between the reserves estimates shown in the SFAS 69 disclosure with the estimates presented in the proposed tables?***

The geographic reporting of reserve estimates, for purposes of disclosures outside the financial statements and for purposes of SFAS 69 disclosures, should be applied consistently. Also, please see our response to question 8.

Separate disclosure of conventional and continuous accumulations

70. ***Should we require separate disclosure of conventional accumulations and continuous accumulations, as proposed?***

No, please see our response to question 40 on accumulation types.

71. ***Should we permit combining of columns if the product of the oil and gas producing activity is the same, such as natural gas, regardless of whether the reserves are in conventional or continuous accumulations?***

Yes. The value of specific reserves to a company is not only based on the method of production and the costs associated with that method but in many cases such values are primarily attributed to the terms of the production sharing contract, licensing agreement, taxes and royalties paid. Whether it is conventional or continuous provides little value to investors and perhaps misleads them into thinking one type of reserve is better than the other.

Preparation of reserves estimates or reserves audits

72. ***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?

No such requirement is appropriate. Companies must fully retain the corporate responsibility for proper reserve determination and reporting and should be able to assign reserve preparation to any party, internal or external, one or many, as they see fit. The corporation bears this responsibility, not the individual. We believe a more effective approach to a clear communication with the investor on the company's reserve determination, validation and assurance/audit process would be to have the company provide a description of that process. Text included in the MD&A should explain the company process and could optionally include any of the proposed information on in-house or third-party reserve estimate preparation or review/audits if the company believes such information would be material to investors. Otherwise, such information could result in obscuring material information contained in a company's Form 20-F or Form 10-K.

73. 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?

No, please see our response to question 72.

74. 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?

No, please see our response to question 72.

75. 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?

No, please see our response to question 72.

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

No, please see our response to question 72.

77. 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?

No, please see our response to question 72.

78. ***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?***

No, please see our response to question 72.

79. ***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?***

No, please see our response to question 72.

80. ***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, please see our response to question 72.

81. ***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, please see our response to question 72.

Contents of third party preparer and reserves audit reports

82. ***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? 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?***

No, please see our response to question 72.

83. ***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?***

No, please see our response to question 72.

84. ***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?***

No, please see our response to question 72.

85. ***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?

No, please see our response to question 72.

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

No, please see our response to question 72.

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

We do not believe the definition is necessary. Please see our response to question 72.

Solicitation of comments on process reviews

88. Should we require disclosure of whether a company has conducted a process review? Notwithstanding the relative lack of rigor of a process review compared to a reserves audit, would investors find such information useful?

No, please see our response to question 72.

89. The proposal does not prohibit disclosure of process reviews. Is there a danger that the public may be confused by such disclosure? Should we prohibit disclosure of any type of reserves-related activity other than the preparation of the reserves estimates or a reserves audit?

No, we feel companies should have the option to disclose any information on these topics the company feels is useful to investors. Thus we do not support such a prohibition.

Proposed Item 1203 (Proved undeveloped reserves)

90. Should we adopt the proposed table? Alternatively, should we simply require companies to reclassify their PUDs after five years?

No. We do not support the proposed table. The volumes reported will have already met the standard of reasonable certainty and must have the company commitment to develop. The various circumstances which may cause development to take longer than five years does not override these fundamental requirements for the definition of proved reserves. Thus we do not support such a reclassification. Please see our responses to questions 31 and 38.

91. 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?

No, we do not support such additional disclosures. This type of disclosure would not be material and has the real possibility of obscuring the material information contained in our Form 20-F.

92. ***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?***

No. The reporting of proved reserve volumes must be fully compliant with proved reserve requirements -- this is not impacted by disclosure (or not) of probable reserves.

93. ***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?***

No, this would require a detailed record of the initial disclosure ("born on") date for each PUD volume and intended development proposal. This is very complex to track over several years as each year our PUDs are re-validated and in many cases updated for new reserve volume analysis and/or a new development plan (thus "reborn"). What may, in a particular area, appear to be a PUD that has remained static ("stale PUD") in most cases will not be the same PUD today as what had been reported as a PUD 5 years ago. To track such PUDs, additional guidance would be needed to clarify how much a PUD can change over time and still be subject to this proposed reporting. Additionally, as noted previously, we do not believe such disclosure is material to investors. Also, please see our response to question 38.

94. ***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?***

No. Please see our response to question 38.

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

If material changes do occur in the PUD tables, under current rules and guidance, these changes would need to be disclosed and discussed separately based on their materiality.

Proposed Item 1204 (Oil and gas production)

96. ***Should we adopt the proposed table?***

Please see our responses to questions 50 to 52 and questions 65 to 69.

97. ***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?***

Please see our response to question 69.

98. ***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.***

These instructions could be eliminated.

Proposed Item 1205 (Drilling and other exploratory and development activities)

99. Should we adopt the proposed table? Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

Please see our responses to questions 50-52, 65-69 and 100.

100. Should we require separate disclosure about the two new proposed categories of wells—extension wells and suspended wells? Does distinguishing these types of wells from exploratory wells and dry wells provide enough clarity regarding the types of exploratory or development activities?

The combination of more detailed geographical breakdown, further delineation of well activities and product classifications will provide a significantly expanded well results table that will be much more granular in nature than the associated financial statement disclosures. While in isolation, we see the objective of requesting the increased disclosures; we believe that this request adds to the disclosure overload that will result in meaningful information being obscured by the shear detail of the data requested. But, there should be further clarity in the definition for a dry well as to what constitutes a ".... well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well." - This is particularly relevant if the proposal to adopt additional disclosure of Probable and Possible reserve volumes is agreed; at present the company's interpretation is that the current definition means "Proved Reserves" volumes need to be associated with such a well before it can be classified as "not Dry". This creates a number of issues for some exploratory settings where a well may be deemed capable of producing Oil or Gas as defined above yet Proved volumes may not be allocated to it until some years into the future, following further investment of resources to prepare detailed technical and economic investment plans. i.e. further clarity should be sought on the definitions.

Proposed Item 1206 (Present activities)

101. Should the disclosure of present activities be made based on the definition of "geographic area" in proposed Item 1201(d)?

Please see our response to questions 65-69.

102. Should we adopt any other changes to the disclosures currently set forth in existing Item 7 of Industry Guide 2 that we propose to codify in Item 1206?

There is no additional data that should be disclosed. However, waterflood and pressure maintenance operations for drilling activities in progress are not consistent with the reporting of completed drilling activities associated with these projects where water injector and gas injector wells are considered as service wells and thus not reported.

Proposed Item 1207 (Delivery commitments)

103. Are the proposed revisions appropriate? Do the proposed revisions make any unintended substantive changes to the existing disclosures?

The proposed revisions are appropriate and we do not believe they alter existing requirements materially.

104. Should we adopt any substantive changes to the disclosures currently set forth in Item 8 of Industry Guide 2 that we propose to codify in Item 1207?

No.

105. Is this disclosure requirement still necessary? Do oil and gas companies still enter into such delivery commitments? Are they material?

Yes.

Proposed Item 1208 (Oil and gas properties, wells, operations, and acreage)

Enhanced description of properties disclosure requirement

106. Are the proposed disclosure enhancements regarding oil and gas properties appropriate? Would this enhanced disclosure be helpful to investors?

No. The proposed disclosure enhancements provide for a significant increase in immaterial disclosure and would only work to obscure material disclosure already contained in our Form 20-F.

107. Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

Please see our response to questions 65-69.

108. Do we need to define any of the terms in the proposed language?

No. If this additional (enhanced) disclosure requirement is included; a description as to what constitutes a level of materiality should be considered. Please see our response to question 106.

Wells and acreage

109. Is the proposed table appropriate? Is there a better way to disclose such information?

Yes, however we do not believe there is any value in separating out continuous accumulations information. Also, please see our response to questions 40, 71 and 100. Again, while in isolation, we see the objective of requesting the increased disclosures; we believe that this request adds to the disclosure overload that will result in meaningful information being obscured by the shear detail of the data requested.

110. Should the disclosures be made based on the definition of "geographic area" in proposed Item 1201(d)?

Yes. The Geographic Area should be consistent throughout, but please see our response to questions 40 and 71.

111. *Is it necessary to disclose wells and acreage in conventional accumulations separate from wells and acreage in continuous accumulations, as proposed?*

No. Please see our responses to questions 40 and 71.

112. *Is this disclosure requirement still necessary? Is disclosure of the number of wells and acreage material? Should we require the disclosures related to wells and acreage only if there is a high concentration of production or reserves attributable to a few wells or limited acreage? If so, should we specify what that concentration would be?*

Yes. This disclosure is appropriate as it stands; it provides an investor with the information as to the proportional spread of interest by geographic area.

New proposed disclosures regarding extraction techniques and acreage

113. *Should we require more specific disclosure regarding extraction activities that do not involve wells? Should this proposed item remain open-ended to permit description of unanticipated technologies?*

No. New disclosure requirements are not necessary. Please see our response to question 46.

114. *Is the proposed disclosure for unproved properties appropriate? Should the proposed disclosure for unproved properties be set forth in proposed Item 1208? Should we move such disclosure to the reserves table in proposed Item 1202, where reserves are discussed?*

Prefer no new disclosures. Please see our response to question 31.

Proposed Item 1209 (Discussion and analysis for registrants engaged in oil and gas activities)

115. *Proposed Item 1209 is not intended to increase a company's disclosure requirements, but specify disclosures already required generally by MD&A. Is such an item helpful?*

The additional proposed MD&A guidance is not necessary. The Commission has provided sufficient clarity to MD&A requirement in multiple Commission releases and enforcement actions. The proposed rules appear to require the inclusion of specific elements, which are not often material to investors. Accordingly, it is likely that the new requirements or guidance would obscure material information required to be included and discussed in our Form 20-F.

116. *Are the proposed topics that an oil and gas company should consider discussing as part of MD&A, whether in the main MD&A section or in conjunction with the relevant table, appropriate? Are there other topics that an oil and gas company should consider discussing?*

Please see our response to question 115.

117. *Should we permit such discussions in conjunction with the relevant table as proposed? Would this aid comparability of the disclosures? Or should we keep MD&A as a self-contained section?*

Registrants should have the option to cross-reference other oil and gas activities data cited within MD&A to other parts of the document.

Proposed Conforming Changes to Form 20-F

118. Should we delete Appendix A and refer to Subpart 1200 with respect to Form 20-F, as proposed? Why? Should we expand the requirements of Form 20-F to require more disclosure than currently required by Appendix A, as proposed? Conversely, should we only update Appendix A to reflect the proposed new definitions and formats for disclosing reserves and production?

Yes. Oil and gas disclosures for foreign private registrants should be consistent with US resident filers and the deletion of Appendix A, and reference to Subpart 1200 would provide consistency and codify all reporting disclosures.

119. Would the proposed reference to Subpart 1200 in Form 20-F significantly change the information currently disclosed by foreign private issuers? If so how? Would such a change be appropriate?

No. Please see our response to question 118.

120. Is the proposed exception for foreign laws that prohibit disclosure about reserves and agreements appropriate? Do such laws affect domestic companies as well? Should Subpart 1200 have a general instruction with respect to such foreign laws?

Yes, it is appropriate that if a foreign country prohibits certain disclosures about reserves and agreements, that prohibition be honored. We are aware that all companies utilizing FAS 69, and in situations where governments restrict the disclosure of reserves, the reporting entity is to indicate that the disclosed reserve estimates do not include figures for the named country (FAS 69, paragraph 17). We recommend similar disclosures for those registrants filing under Form 20-F.

121. Are the proposed revisions to Instructions to Item 4.D appropriate with respect to foreign private issuers that have extractive activities other than oil and gas producing activities?

Yes, for consistency.

Impact of Proposed Amendments on Accounting Literature

Consistency with FASB and IASB Rules

Change in Accounting Principle or Estimate

122. Are the proposed changes more properly characterized as a change in accounting principle or a change in estimate under SFAS 154?

These proposed changes are more properly characterized as a change in estimate under SFAS 154.

123. Would it be appropriate to consider the changes as a change in accounting principle, but specify that no retroactive revision of past years would be required?

No, these proposed changes are more properly characterized as a change in estimate under SFAS 154. Accordingly, no retroactive revision should be considered.

124. If we required retroactive revision of past years, would companies have the historical engineering and scientific data to make such revisions? If not, are there alternatives to retroactive revision that we should consider?

While the historical data may exist, the staff work burden to recreate what was known and when (to ensure only data available as of each prior year-end of the retrospective period were used) would be enormous. It is hard to see how companies' investors would be well served by diverting staff attention from finding and developing new business opportunities or maintaining current business operations just to re-create historical reserve estimates using the new rules.

Differing Capitalization Thresholds Between Mining Activities and Oil and Gas Producing Activities

125. How should we address these inconsistencies between oil and gas accounting rules and mining accounting rules?

There should be no inconsistencies in the accounting rules for all extractive activities.

126. Should we permit companies that extract, through mining methods, materials from which oil and gas can be produced to continue to capitalize costs under mining rules, or should we require them to capitalize costs based on oil and gas rules? Are there circumstances involved with mining operations, different from oil and gas operations, that justify capitalization of costs of proved plus probable reserves, as opposed to only costs of proved reserves?

There should be no inconsistencies in the capitalization requirements for all extractive activities.

Price Used to Determine Proved Reserves for Purposes of Capitalizing Costs

127. Would the effect of such changes be material or have a material effect on historical amortization levels?

Please see our responses to questions 14 and 15.

128. Would the effect of such changes be material or have a material effect on comparability? Please provide any empirical evidence to support your conclusion.

Please see our responses to questions 14 and 15.

129. Would it be appropriate to continue to require the use of the year-end price for purposes of determining reserves for purposes of amortization expense while using a different price for purposes of disclosing reserves estimates in Commission filings? This would result in a different value associated with the use of the term "proved reserves" for purposes of disclosure, as opposed to the use of that term for purposes of accounting. Would this be

confusing? Should we use a different term? Should we otherwise clarify the two different meanings of that term in different contexts?

The use of average prices to estimate proved reserves, for purposes of disclosures outside the financial statements and for purposes of SFAS 69 disclosures, should be applied consistently. Also, please see our response to question 8.

Impact of the Proposed Codification of Industry Guide 2 on Other Industry Guides

130. Is it appropriate to codify Industry Guide 2 separately from the other industry guides? Should we merely amend Industry Guide 2 and codify it with all of the other industry guides when they have been updated?

We have not objection to the codification of Industry Guide 2. Additionally, please see our response to question 46.

131. Would the codification of Industry Guide 2 overrule or otherwise affect any of the disclosures required in the other Industry Guides?

Please see our response to question 46 and the applicability of Guide 7.

Solicitation of Comment Regarding the Application of Interactive Data Format to Oil and Gas Disclosures

132. Should we adopt rules that require oil and gas disclosures to be provided in interactive data format? Instead of requiring such formatting, should we only permit the filing of oil and gas disclosures in interactive data format? What are the principal factors that we should consider in making these decisions?

The SEC issued Release 33-8924, Interactive Data to Improve Financial Reporting, earlier this year, with a comment deadline of 1 August, 2008. That release addressed proposed mandatory XBRL submittals for a Company's financial statements and footnotes over a staggered implementation period. Accordingly, if the SEC adopts this proposal, all oil and gas disclosures reflected, as supplemental information within a Company's financial statements will be mandatory at some future date. Subject to the SEC's adoption of these interactive data requirements, we recommend that registrants be permitted to submit oil and gas disclosures reflected outside of the financial statements in XBRL for consistency.

133. If we require oil and gas disclosures to be filed in interactive data format, should we provide for a voluntary phase-in period to create a well-developed standard list of electronic tags? Without a requirement, would the development of products for using interactive data meet the needs of investors, analysts, and others who seek to use interactive data? Would a large percentage of oil and gas companies provide interactive data voluntarily and follow the same standard, if not required to do so?

Yes, the Commission should provide a phase-in period. The Commission should also include a sunset provision on the any proposal to require use of XBRL in order that value to investors can be evaluated to see if it is greater than the additional costs placed on companies.

134. ***Would investors, analysts, and others find presentation of oil and gas disclosures helpful if presented in interactive data format? In what ways would such users of the information find such a format beneficial?***

We do not know if there will be any value to investors or analyst. We can inform the Commission that no investor or analyst has requested us to present such information using the XBRL standard. Please see our responses to questions 132 and 133.

135. ***As we note above, there is not currently a well-developed standard list of electronic tags for the oil and gas disclosures. Are there any obstacles to creating a useful standard list of electronic tags for the oil and gas disclosures? Is the type of data presented in the proposed table conducive to interactive data format? Would it be particularly difficult to create standard electronic tags for any of the proposed data? Would there be any obstacles to providing comparable data in interactive format?***

Please see our responses to questions 132 and 133.

136. ***Would it be useful for the data in the proposed tables to interact with other data in Commission filings? If so, which data?***

Please see our responses to questions 132 and 133.

137. ***If we adopt rules requiring oil and gas disclosures in interactive data format, should we require the use of the Extensible Business Reporting Language (XBRL) standard? Are any other standards becoming more widely used or otherwise superior to XBRL? What would the advantages of any such other standards be over XBRL?***

Please see our responses to questions 132 and 133.

Implementation Date

138. ***Should we provide a delayed compliance date, as proposed above? If so, is the proposed date appropriate? Should we provide more or less time for companies to familiarize themselves with the proposed amendments?***

Yes, we concur with implementation dates outlined in the proposal presuming these changes are considered a prospective change under SFAS 154 and the proposed rules are adopted by the Commission and communicated to the public by year-end.

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

No. We believe adoption of these rules should occur by all companies on the same date.

Request for Comment

140. ***We request and encourage any interested person to submit comments regarding: The proposed rule changes and additions that are the subject of this release; Additional or different changes; or Other matters that may have an effect on the proposals contained in this release.***

These issues are addressed in the text of our response letter.