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COMMENTS ON PROPOSED RULES CHANGES: MODERNIZATION OF THE OIL AND GAS REPORTING REQUIREMENTS (SEC File # S7-15-08)

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The following are my personal professional opinions regarding the SEC proposed amendments to their current oil and gas disclosure rules. These comments are based on my experience as a geological consultant advising companies on petroleum resources assessment and reporting.

I commend the commission on a thorough review and analysis of the replies to the December 2007 Concept Release. Implementation of the Proposal would significantly improve investors' ability to understand issuer's entitlement to future production and cash flows through Reserves disclosures.

My comments submitted herein are focused on four issues:

- disclosure of Unproved Reserves
- scope of oil and gas activities
- sales product definition and netback pricing
- quality assurance processes in Reserves reporting

Disclosure of Unproved Reserves

It is my personal recommendation that the SEC mandate disclosure of both Proved and Probable Reserves. Implementing this mandate, in addition to improving clarity for investors, would provide:

- increased alignment with the current Reserves evaluation practices as used internally by companies to make project investment decisions. While companies assess the full range of Reserves and Resources, where a single expected result is selected as the basis for production and cash flow forecasts, that result is most often the sum of Proved plus Probable (2P) Reserves.

- increased alignment with petroleum Reserves disclosure rules as adopted by other international regulatory agencies (e.g. Canada, UK, Australia). While there is variation in the range of optional disclosed resource classes and categories, a common denominator is the requirement to disclose Proved and Probable Reserves. Both the Society of Petroleum Engineers (SPE) and NI 51-101, through its reference to the Canadian Oil and Gas Evaluation Handbook (COGEH), endorse Proved plus Probable as the best estimate of Reserves.

- increased alignment with minerals disclosure rules. SEC Industry Guide 7 requires disclosure of Proved and Probable Mineral Reserves. Most other regulatory agencies have adopted the Committee for Minerals Reserves International Reporting Standards (CRIRSCO) international template that provides for disclosure of both Proved and Probable Mineral Reserves and also Mineral Resources. Again the common denominator is Proved plus Probable Reserves. Based on joint research by SPE and CRIRSCO, it was concluded that the technical and commercial certainty conveyed in Proved plus Probable Reserves estimates is very comparable between the two industries.

- alignment with evolving international accounting standards derived from the International Accounting Standards Board (IASB) Extractive Activities project. While the study process is still ongoing, there is early indication that the basic asset for both petroleum and minerals would be a fair market assessment of Proved plus Probable Reserves.

As discussed in section XI of the Proposal, once the option to disclose Probable Reserves is made available and, as expected, a significant number of companies exercise this option, there will be increased pressure on other issuers to make similar disclosures. My recommendation to mandate both Proved and Probable disclosures would avoid this transition period in which comparability of companies' Reserves using different options would be confusing for investors.

Assuming that the SEC were to adopt a mandated disclosure of both Proved and Probable Reserves, the text should be adjusted to reflect that evaluators must first establish that the quantities assessed are associated with projects that meet the Reserves criteria, both technical and commercial; thereafter, estimates of recoverable and marketable quantities are allocated to Proved and Probable categories based primarily on technical certainty.

Probable Reserves may be assessed as discrete increments to Proved or alternatively may be the calculated difference between Proved and Proved plus Probable (2P) scenario estimates. Under PRMS and COGEH guidelines, both Proved and Probable estimates may be subdivided into Developed and Undeveloped based on the funding and operational status of required wells and facilities.

It is my personal recommendation to not include Possible Reserves in petroleum disclosures. Despite repeated attempts by the SPE and others, most recently in PRMS, to clearly separate Reserves from Contingent Resources, it is my observation that many evaluators still combine more risky new projects with legitimate upside potential in existing projects under the Possible Reserves category. Thus, although upside potential may be considered internally in making investment decisions, it would be extremely difficult to rely on these estimates for company-to-company comparison purposes. Only by simultaneously disclosing Possible Reserves and Contingent Resources could one gain a total view of projects with both upside uncertainty and more limited chance of commerciality. As PRMS guidelines are more fully implemented internally, future consideration may be given to optional disclosures of Possible Reserves.

Also of concern is that arithmetic summations of Proved plus Probable plus Possible (3P) Reserves will yield extremely optimistic company and country totals in large, diversified portfolios of fields/projects; such summations would raise public expectations around results that have minimal chance of occurring. This is the same statistical effect that makes arithmetic summations of Proved Reserves extremely conservative. A further advantage of a mandated 2P disclosure is that a best estimate that approximates P50 in probabilistic analyses often approaches the statistical mean of distributions at the field or project level. Since, under the central limit theorem, the "sum of the means is equivalent to the mean of the sums", the divergence between deterministic summations and probabilistic aggregations for 2P reporting at country and company aggregate levels will be acceptable.

Another consideration is that the Possible category is not part of the Mineral Reserves disclosures as defined by CRIRSCO and Industry Guide 7; moreover, comparability between Possible petroleum Reserves and Inferred Mineral Resources is difficult to fully document. Restricting petroleum disclosures to 2P Reserves ensures improved comparability with current minerals disclosures and supports any future harmonization of the respective codes.

Scope of Oil and Gas Activity

I agree with focusing the definition of oil and gas producing activities on the final product of such upstream activities. I support the recommendation that the extraction of bitumen from oil sands, extraction of kerogen from oil shales, and production of natural gas from (in situ) coal beds should be considered oil and gas producing activities. This should apply irrespective of the extraction process; that is, mined bitumen and oil shale would qualify as oil and gas activities.

I understand the dilemma where coal, although mined primarily for direct power generation, can be processed to generate natural gas (and hydrocarbon liquids). Traditionally, the industry has separated coal from petroleum based on its higher carbon to hydrogen ratio. I agree that it would be preferable to retain mined coal as Mineral Reserves.

The same dilemma may occur regarding mined oil shale. Note that in "oil shales" the target natural energy mineral is kerogen which has not matured to the extent that it can be characterized as "crude oil". Kerogen and bitumen may be considered as immature and over-mature states respectively of petroleum. Given that primary market will be synthetic crude oil, oil shale mining, similar to bitumen mining, should be included as an oil and gas activity**.**

The guidelines may be further clouded when future technologies for in situ upgrading of oil sands and oil shales are employed. It is assumed that the material (synthetic oil or gas) recovered at the wellhead from such operations would be defined as the produced hydrocarbons and not subject to the SEC exclusions regarding synthetic products derived from upgraders installed as part of surface production facilities.

Note that closer alignment of the disclosure rules for petroleum and minerals would, to a large extent, alleviate this dilemma. For example, both coal for power generation and for gasification should be disclosed as Proved plus Probable Reserves where the distinction of petroleum versus minerals would not impact the technical volumes but the supplemental disclosures could be based on netback pricing from the primary market.

Sales Product Definition and Netback Pricing

While I agree that the Reserves quantities should be stated in terms of the "natural product" as derived from the extraction activity, **additional guidance is required to provide clarity and consistency in defining the "sales product" and its specifications at custody transfer plus the adjustments required to align with benchmark pricing.** The following examples are provided to illustrate the issue:

- Part of the field processing of natural gas to extract liquid hydrocarbons also involves sufficient removal of impurities/non-hydrocarbons to meet product specifications at the custody transfer (terminal) point. For example, if natural gas from a field contains 4% CO_2 and if pipelines allow a maximum of 2% CO_2, it should be allowable to claim gas Reserves quantities including 2% CO_2 as this would match the processing costs actually incurred, sales volumes actually delivered, and product pricing received. Conventional reservoirs with large portions of non-hydrocarbons can be viewed as "non-traditional" operations.

- A Liquefied Natural Gas (LNG) facility provides a high degree of purification and delivers a product in a specific physical form. Typically, the areas where LNG facilities are installed lack a pipeline market and thus directly applicable benchmark pricing. Under proposed guidance, there appears to be two alternatives for base Reserves disclosures
  1) Measure the actual LNG gas delivered at the plant outlet after processing losses plus any hydrocarbon gases and liquids extracted and marketed along with prices actually received. Both future sales gas (as LNG) and sales liquids would be reported as Reserves, or
  2) Measure the raw gas delivered to the plant inlet but establish "adjustments" to a referenced regional pipeline gas price based on hypothetical processing costs to generate gas meeting pipeline specifications and including a premium for liquid content. Reserves disclosure would be in the form of raw wet gas.

  Supplemental Reserves disclosures of dry gas and liquids could then be based on netbacks from actual sales of LNG and plant hydrocarbon products.

- Under proposed SEC guidance only option # 2 from above could be applied to bitumen that is subsequently upgraded to Synthetic Crude Oil (SCO) prior to custody transfer. It is noted that the bitumen delivered to the upgrader is not in the purified form required for applying standard bitumen sales pricing. Thus evaluators must examine the full plant-processing stream to compute costs to create a "virtual bitumen volume" according to sales product specifications for basic Reserves disclosures. A supplemental disclosure could utilize netback from the delivered SCO volumes and any other hydrocarbon plant products derived.

Conceptually, I support proposed rules to allow supplemental disclosures to support alternative Reserves estimates using "netback pricing" to define economic limits. However, both the base and supplemental disclosures require additional guidelines/principles regarding adjustments to volumes, prices and costs related to all projects but especially for integrated production and processing projects regarding:

1) clarifying that specifications of the sales products to which pricing is applied is based on either a documented sales contract or as accepted at regional hubs.
2) clarifying that Reserves quantities should be stated using these same product specifications and thus may include non-hydrocarbons to the limit specified at the custody transfer point.
3) calculating costs to create such a hypothetical specified sales product.
4) using revenue from sales of associated non-hydrocarbons to offset operating costs.
5) using portions of the produced petroleum for lease fuel in production (e.g. steam generation) and processing or as diluents for transportation. If consumed lease fuel is claimed as a Reserve, an associated operating expense should be assigned.
6) since many of these large processing facilities are shared among multiple reservoirs, and fields including those with varying working interests, the guidelines should accommodate cost allocation including income from "rental" of excess facilities capacity.

Quality Assurance in Reserves Reporting

I support the SEC requirement that the process of estimating and auditing Reserves should be endorsed by Qualified Reserves Evaluators (QRE's) and Qualified Reserves Auditors (QRA's) respectively using criteria as proposed.

While all members of international assessment teams may not individually meet these qualifications, including membership in a Self-Regulating Organization (SRO), each company may designate an employee that is certified with an SRO or state/provincial agency to review and take responsibility for the Reserves report. The company should make available a description of their assessment, review, and audit processes with specific reference to organizational structures that promote objectivity and freedom from bias. The same processes and evaluator qualifications should apply to Proved and Probable (and Possible) Reserves.

Quality assurance processes may involve use of 3rd party consulting firms to assess or audit portions, but not the total, of the company's resources portfolio. For example, by asking for a Reserves report (or audit) of a selected group of properties that make up 20% of total 2P Reserves and varying the individual properties each year, a company may achieve almost 100% coverage over the span of 5 years. Remembering that the ultimate responsibility rests with the company and not the 3rd party consultant, issuing companies should be given the flexibility to utilize 3rd party evaluators in whatever role they deem appropriate and not controlled by artificially set percentages; however, the overall process should be explained and documented for the benefit of investors.

Summary

I applaud the open and transparent process employed by the SEC in gathering and considering industry and public feedback on their Proposal regarding "Modernization of Oil and Gas Reporting Requirements". I hope that my comments provide a useful perspective and I remain available to expand and clarify my recommendations.