December 12, 2010

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Department of the Interior
Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE)
381 Elden Street, MS–4024
Herndon, Virginia 20170–4817

Attn: Regulations and Standards Branch (RSB)

Re: Increased Safety Measures for Energy Development on the Outer Continental Shelf, 1010–AD68

Dear Sir or Madam:

The April 20, 2010 Macondo tragedy resulting in the loss of 11 lives, spillage of ~4.9 MMBO into the Gulf of Mexico and sinking of the Deepwater Horizon is a great loss to our Industry and our Country. Macondo serves to remind us that prevention of total loss of well control thru validation of barriers to establish well integrity must be our primary focus. Further, when barriers fail, our rig site personnel must be capable and willing without hesitation to properly shut-in the well.

Unfortunately, in the case of Macondo; 1) The barrier validation process failed to properly establish well integrity, 2) When positive flow indicators first appeared the well could have been shut-in and likely controlled, 3) When the well was finally shut-in, the method of shut-in allowed hydrocarbons to saturate the rig's topside instead of being diverted overboard and 4) The emergency BOP control systems appeared to fail to secure the well. Had any one of the four items been properly executed or worked as intended, the resulting events would have been significantly less catastrophic.

Once a blowout occurs, quick response is necessary to reduce pollution and economic loss. It is apparent from the results that either: 1) We were not prepared to respond to this event or 2) We were incapable of making the necessary hard decisions early and move towards the quick capping option. Many in our industry could not understand why the well was not capped sooner. Removal of the LMRP from the BOP or BOP from the Wellhead seemed to be a logical next step to reduce the flow or ultimately shut-in the well. Many rigs responded to emergency and each one had one or two 18-3/4" BOP's which could have been used to cap the well.

Macondo has forced the Agency to promulgate new drilling safety rules. Several of the rules will help improve offshore safety while others focus on administrative issues that result in additional paper work. Many of the administrative requirements and processes to implement them will result in delays and increased operational risk exposure. The

Agency and Industry should diligently work together to ensure the spirit and intent of the new rules are applied tactically and consistently for maximum impact.

The Gulf of Mexico has been the innovation incubator for the rest of the world in terms of deepwater exploration and development. Houston, Lafayette and New Orleans provide many of the ideas, engineering and services that have enabled development of deepwater oil resources. Finally, the Agency and Industry must continue to work together to establish effective rules and industry standards which improve safety while maintaining a competitive leasing and operating environment. Rulemaking must be mindful of compliance timeframes, expected improvement to operating risk and effects on business and industry.

BOEMRE is urged to consider the comments submitted below, and publish a final rule that effectively addresses the best technical comments received from all sources. BOEMRE is also urged to follow standard notice and comment rulemaking process in the future to allow sufficient time for compliance and ensure the effects of compliance are properly considered on business and industry.

I. BOEMRE should immediately issue a final rule that revises 30 CFR §250.198(a)(3) to clarify that it will not attempt to read the word "should" as "must," revising more than 14,000 discretionary, non-mandatory provisions in 80 API standards without any review by BOEMRE as to the effects of its actions.

> The effect of incorporation by reference of a document into the regulations in this part is that the incorporated document is a requirement. When a section in this part incorporates all of a document, you are responsible for complying with the provisions of that entire document, except to the extent that section provides otherwise. When a section in this part incorporates part of a document, you are responsible for complying with that part of the document as provided in that section. **If any incorporated document uses the word *should,* it means *must* for purposes of these regulations."**
> 30 CFR § 250.198(a)(3) (emphasis added).

As promulgated, the last sentence would have the effect of revising over 14,000 discretionary provisions in 80 standards without any review of the effect of this blanket requirement. The blanket revision represented in 30 CFR § 250.198(a)(3) will impose many conflicting, confusing or impossible compliance requirements without any additional safety benefit.

There is no regulatory basis for adopting a blanket requirement for all discretionary language to become mandatory. BOEMRE has not stated any added safety benefit to be gained from revising language in over 14,000 discretionary provisions. It appears that the agency has not reviewed the actual discretionary

provisions the last sentence of 30 CFR § 250.198(a)(3) would amend and thus have promulgated numerous mandates with unintended consequences.

To highlight this issue and these conflicts, commentary is provided on the following key standards: Spec 6A, RP 65-2, RP 53, MPMS Chapter 7, 20.1 and 21.1. These documents represent an important subset of the referenced standard and include valves, blow-out preventers, cementing practices, and measurement techniques.

A. API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, 19th Edition, July 2004

The following are requirements in conflict if must is substituted for should:

10.2.2.3 Thread counter-bores - End and outlet connections, equipped with internal threads, may be supplied with or without a thread-entrance counter-bore. Internal threads, furnished without a counter-bore, **should** have the outer angles of 45° to a minimum depth of *P*/2, as illustrated in the figure belonging to Table 61* and Figure 10. Internal threads, furnished with a counter-bore, **should** conform to the counter-bore dimensions specified in Table 61* and the bottom of the counter-bore **should** be chamfered at an angle of 45°. As an alternative, counter-bore dimensions may be as specified in API Spec 5B.

Conflict: Clause prescribes bore dimensions with no option, and then allows for alternatives.

Annex A, Informative, Purchasing guidelines, A.1 General - To use this annex, a copy of the data sheets **should** be completed as accurately as possible. The typical configurations **should** be referred to, as needed, to select the required equipment. The decision tree, given in Figure A.14, together with its instructions, provides the recommended practice as to which PSL each piece of equipment **should** be manufactured. A copy of the data sheet **should** then be attached to the purchase order or request for proposal.

Conflict: Highlighted clause is prescriptive and does not allow for changes to accommodate any needed variations specific to unique site conditions.

Annex D, Informative, Recommended flange bolt torque, D.1 General - It has been shown that the torque values given in the tables of this annex are acceptable values for use in type 6B and 6BX flanges in some services. The user **should** refer to API TR 6AF, API TR 6AF1, API TR 6AF2 and API Spec 6FA for data on the effects on flange performance of bolt preload stress and other factors. It **should** be recognized that torque applied to a nut is only one of several ways to approximate the tension and stress in a fastener.

Conflict: Makes API TR 6AF, API TR 6AF1 and API TR 6AF2 no longer bibliographic references, but now normative references.

Annex H, Normative, Design and manufacture of surface wellhead running, retrieving and testing tools, clean-out tools and wear bushings, H.2.3 End connections - Torque-operated tools **should** preferably be threaded left-hand for make-up and right-hand for release to prevent inadvertently backing off of casing/tubing/drill pipe connections during operation/disconnection.

Conflict: Does not allow for changes necessary for the specific site configuration. H.3.3 Mechanical property requirements - The material requirements for wear bushings shall comply with the manufacturer's written specification; however, the hardness must be between 241 HBW and 321 HBW.

Conflict: Potential conflict with manufacturer specification.

B. API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Operations,* 3rd Edition, March 1997, Reaffirmed: September 2004, 2-Year Extension: May 2010

While the regulations only cite six sections of RP 53, some potential conflicts do exist:

17.11.6 and 18.11.6, Maintenance, Lubricants and Hydraulic Fluids - The original equipment manufacturer **should** be consulted for the proper lubricants and control fluids to be used on surface applications, a light mineral-based hydraulic fluid can be used.

17.11.7, Maintenance, Weld Repairs - The original equipment manufacturer **should** be consulted to verify proposed weld procedures.

Conflict: The above statements will be impossible to comply with if the BOP Original Equipment Manufacturer (OEM) is no longer in business.

C. Manual of Petroleum Measurement Standards Chapter 7, Temperature Determination, 1st Edition, June 2001, Reaffirmed March 2007

While there are already several “musts” already used in the document, in regard to calibration of devices for custody transfer and safety requirements, there are still potential conflicts in the following areas:

5.1, Fixed Automatic Tank Thermometers (temperature measurement in tanks) - The selection of a single-point (spot), mid-level, multiple-point, or an averaging ATT **should** be made based on the expected tank temperature stratification and the accuracy requirements (custody transfer versus inventory control).

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Conflict: Should and shall (must) requirements require that temperature measurements be taken at certain depths in tanks. It could be difficult to "hit" these depths exactly as the conditions are not always conducive to perfect measurement due to field conditions.

5.3, Glass Thermometers and traceability - Glass reference thermometers include complete-immersion thermometers, partial-immersion thermometers, and total-immersion thermometers (see Figure 4 and refer to ASTM E 344). These thermometers **should** conform to ASTM E 1 specifications for thermometers or to National Institute of Standards and Technology (NIST) specifications. Calibration must be traceable to NIST-certified instruments.

Conflict: All thermometers should be traceable to the National Institute of Standards and Technology, NIST. NIST recently announced that they will no longer calibrate Mercury in Glass Thermometers after March of 2011.

Appendix D: Test Procedures for determining immersion times of measuring devices – All tests start with glass thermometers in their assemblies stabilized at the ice point…suggested bath temperatures at which immersion times **should** be measured are provided in Table D-1.

Conflict: Immersion times are specified for PETS and woodback case assemblies. These times are listed as "recommended", but the standard implies "should" in the use of these times as they are also referenced as required. This could pose problems as the times vary from 30 seconds to 45 minutes for in motion measurements and 10 minutes to 60 minutes for stationary measurements. The field personnel taking these measurements may not be able to time immersions exactly according to the required values, again influenced by field conditions.

D. Manual of Petroleum Measurement Standards Chapter 20, Section 1 – Allocation Measurement, 1st Edition, September 1993, Reaffirmed March 2006

1.1, Introduction - Although allocation measurement may not meet the requirements for custody transfer measurement in all cases, it is still possible to refer to existing custody transfer industry standards for the basis of measurement. Where this allocation standard does not specifically address a measurement related issue, it **should** be assumed that custody transfer standards apply.

Conflict: Allocation measurement and custody transfer standards may not always be assumed to be one in the same. In fact, the API Committee on Production Allocation and Measurement is developing an entire series of standards to address these unique issues. Changing this "should" to a "must" would obviate the entire need for these documents, at least from a regulatory perspective.

1.5.2.3 Differential Pressure Devices - Generally, on a bellows secondary element, the gauge lines **should** be connected to the top connections of the bellows assembly.

However, depending on the liquid being measured, it may be preferable to connect to the bottom bellows connections.

Conflict: Changing the “should” to a “must” means the second sentence is no longer an option, even though this option may be preferable in some cases depending on field and reservoir conditions.

1.7.2.3.1.1, Factory calibration - The relationship between dielectric constant and water cut varies with different types of hydrocarbons and water. The analyzer **should** be calibrated in the factory using the hydrocarbon liquid and water identical or similar to those in the actual application. A calibration curve between the actual water cut and probe output **should** be developed and incorporated into an associated electronic processor device.

Conflict: How would industry prove that the hydrocarbon liquid and water used to calibrate the analyzer in the factory will be similar to that found in the upstream production environment? And as the crude oil/gas may vary greatly in composition as production progresses, how can this be addressed by calibrating the analyzer in the factory?

1.15.2, Calculation Procedure - Allocation calculations **should** account for 100 percent of sales and shrinkage. This can be done on a volume basis, on an energy content basis, and by test car GPM. The last step is to prorate each volume to actual field or system sales.

Conflict: This is the very core of allocation measurement, and in certain cases the calculation procedure may yield 100%, but may not in others due to field and reservoir conditions.

E. Manual of Petroleum Measurement Standards Chapter 21, Flow Measurement Using Electronic Metering Systems, Section 1 – Electronic Gas Measurement, 1st Edition, August 1993, Reaffirmed July 2005

1.7.2, Gauge/Impulse lines – Whenever possible, pulsation **should** be eliminated at the source.

Conflict: Field conditions may require pulsation be eliminated at both the source and at other locations to achieve optimal results.

1.8.5.1, Ambient temperature Effect – Operating temperature range and its corresponding effect on measurement uncertainty (that is, percent full scale/degrees temperature change from reference) **should** be listed in the manufacturer’s performance specifications and **should** be considered when selecting and installing EGM equipment

Conflict: Changing these “shoulds” to “musts” would add a performance criteria not specifically envisioned by the consensus committee and would add an additional requirement to the manufacturers of these measurement devices that may not be appropriate in all cases.

F. Additionally, we would like to comment on proposed revisions to RP 17H, *Recommended Practice for Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems*, 1st Edition, July 2004, Reaffirmed: January 2009, and RP 17M, *Recommended Practices on Remotely Operated Tool (ROT) Intervention Systems*, 1st Edition, April 2004, Reaffirmed: January 2009:

One important note to consider on the ROV document (17H) is that it is currently under revision. When completed, it will be a merged document of the current 17H and 17M (Remotely Operated Tools, ROT) documents.

With this initial effort in revising the document, the emphasis was placed on integrating the two components (ROV and ROT) into one document. Therefore most of the current design recommendations/considerations in both documents are not impacted. The document is about to undergo a technical review ballot, so the following items may be impacted by the end of that review.

The new document will include the following changes (if left in its current state through the ballot process):

- ROVs are to be classified dimensionally (small, medium, large) and recommended sizes are noted in order to introduce a standardized method of increasing access to the interface
- Additional design considerations for working platforms
- Increased docking receptacle loading and consideration of failsafe requirements
- Additional handle (used in conjunction with a ROV manipulator or purpose-built tooling to allow direct operation of the interface) design considerations.
- An entire new section on *Coloring and Marking* (to be used as a guidance map for the intervention operations by identifying the structure and orientation; identifying the equipment mounted on the structure and intervention interface; identifying the position of any given part of the structure relative to the complete structure; and identifying the operational status of the equipment, e.g., connector lock/unlock and valve open/close.)

Although the new (combined ROV and ROT) document is about 1.5 years away from publication, if it does get cited by reference in the regulations, it will incorporate ROT equipment by default, currently not part of the on-going discussions. Furthermore, a

review of that proposed document shows 362 uses of the work "should". If they were to be elevated to a "must", it would have serious impact on the equipment since there are 13 clauses that deal with equipment configuration/conceptualization and 193 clauses that deal with equipment design that would become prescriptive. At that time, this document would need to be reviewed for potential internal conflicts associated with such a change. The subcommittee plans to simultaneously withdraw the current 17H and 17M documents when the *new* 17H document is released.

II. §250.198(h)(79); Adoption of API RP-65—Part 2 with "Should" as "Must";

API RP 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition will be published in December 2010. The Second Edition will incorporate learnings from the Macondo well incident, enhance the description and classification of well control barriers, and define testing requirements for cement to be considered a barrier. The Second Edition also revises Annex D into a checklist based on the requirements of the document. ***BOEMRE should update the interim final rule to incorporate the 2nd Edition by reference.***

Clarification is requested on how RP 65-2 will be used; will a minimum pre-cementing score be required for each cement job? and then evaluated after the job also?

RP-65 Part 3.2; A mechanical barrier is defined in 2.1 as "a verifiable seal achieved by mechanical means between two casing strings or a casing string and the borehole that isolates all potential flowing zones at or below the wellhead, BOP or diverter." This seal inside permanent devices such as wellheads or packers should be installed, energized, tested and/or verified before nippling down the BOP or diverter.

Conflict: This will eliminate all conventional wellheads from OCS operations. Many conventional wellheads currently exist and when these wells are re-entered and casing is cut and pulled for a ST, then the wellhead is obsolete if a long string is to be run. Additionally, conventional wellheads are used with MCSS (mudline suspension systems). To achieve the requirement, operators will be required to install an ECP or run a liner and tieback, both of which will provide additional leak paths and complexities to operations. Alternatively, BOEMRE should require Operators to perform a pressure test on the annulus prior to nippling down diverters or BOPE in lieu of requiring a mechanical barrier. By performing a pressure test, operators can be assured that the cement has provided an effective seal. This improves the current WOC requirement and validates the WOC is sufficient as well as ensures good placement of cement between casings.

RP-65 Part 3.3; If washing out between strings is required for a given well plan and the probability exists that fluids will flow (i.e. the well contains zones that may flow behind the pipe), then a subsurface mechanical barrier may be recommended since the

effectiveness of a BOP is negated by the small-diameter tubulars run inside the BOP or diverter to wash out the cement. If a subsurface mechanical barrier cannot be used to control flows in this situation, then the annulus should not be washed out until the cement has set sufficiently to prevent a flow (which may preclude washing out at all).

Conflict: This new requirement needs clarification. There are numerous was to achieve the goal of washing out without placing small-diameter tubulars across the diverter or BOP. The base plate could have access ports with valves to enable running of a grout string below the diverter which would still allow the diverter to be effective. Cement can be flushed to a point below the mud line with mud by bull heading and if a MLS system is used, flushing ports may be used to circulate out the annulus without the use of small diameter tubulars.

RP-65 Part 3.7.3.1; This planning should include all parties involved in doing the work and specifically should include the operator, drilling contractor, cement contractor and the contractor providing the mechanical barrier, if applicable. In all cases, the operator and contractor should have a plan to minimize the time from the start of ND the BOP to securing the exposed annulus with slip and seals.

Conflict: RP 65 Part 3.2 states that a mechanical barrier should (must) be installed in the wellhead or below the diverter or BOP before nippling down. This section states that nippling down to install slips and seals must be planned. Both statements are reasonable in the context of the API definition of "Should", however they are contradictory with the BOEMRE definition of "Should". Operators must be allowed to plan and execute their business without contradictory rules referenced by the CFR's. Testing of annuli after the appropriate WOC time would eliminate most of the well control events during N/D & N/U operations. Having a mechanical barrier in the wellhead prior to nippling down is desirable; however it is not always practicable.

RP-65 Part 3.7.3.3 (w.r.t. to nipple down operations when a mechanical barrier is not used); the Operator should reconfirm the course of action with the regulator or permitting authority if any conditions discussed in 3.7.1 occur. 3.7.1 Conditions are; 1) substantial loss of returns while pumping cement; 2) delays in getting cement in place, such as pump interruptions that could lead to poor mud removal and poor cement consistency; 3) premature returns of cement to surface; 4) high gas units in the drilling mud prior to cementing.
Conflict: First, Section 3.2 states a mechanical barrier should (MUST) be installed prior to nippling down. This decision tree provides a means to nipple down when a mechanical barrier is not used. However, if Operators must use a mechanical barrier, then this decision tree is a moot point. In addition the terms substantial, premature and high in the 3.7.1 conditions are vague and could lead to arbitrary decisions, inconsistency, confusion and delays when dealing with regulators. Alternatively, suggest that prior to nippling down a diverter or BOP, the cement must have reached a minimum of 50-psi and the annulus must be pressure tested to; 1) 150 psi over the FG of the previous casing shoe provided cement is placed above the previous shoe, 2) to leakoff of the previous shoe if cement is placed below the previous shoe and 3) negative tested by draining the stack to the wellhead and monitoring for inflow for at least 0.5 hour prior

to nippling down. There should be no request to obtain regulatory approval if these conditions are met.

RP-65 Part 3.7.3.4 Procedures: Step, once the WOC time in hours is determined by lab tests for the specific cement slurry, the operator should wait on the cement to set for that amount of time prior to removing or disabling the BOP equipment, or have a mechanical barrier seal in place and verified on that annulus.

Conflict: First, Section 3.2 states a mechanical barrier should (MUST) be installed prior to nippling down. This decision tree provides a means to nipple down when a mechanical barrier is not used. However, if Operators must use a mechanical barrier, then this decision tree is a moot point. Consistency in requirements is needed. Annuli should be tested prior to nippling down which will verify that an effective barrier is in place.

RP-65 Part 4.2 Hole Geometry; Drilling and fluid management practices should strive to minimize hole washout via proper bit hydraulics and shale inhibition.

Conflict: Often times in conductor and surface hole, dispersion is the preferred choice for dealing with Gumbo. Unconsolidated sands tend to washout more than the shale. Dispersion can eliminate gumbo attacks, hole packoff, stuck pipe, surge and swab and other hole problems. "MUST STRIVE" wrt to inhibition is a goal that has open boundaries. It can be a consideration but should not be a requirement! Generally this may be a good goal, however the ultimate goal is getting casing to bottom once the hole is drilled. This requirement in the CFR's is qualitative, arbitrary and could be detrimental to getting casing to bottom. Circulation time in shallow sections washes out the hole as well but ensures casing is run to bottom.

RP-65 Part 4.2, Hole Geometry - The relationship between hole size and casing size **should**, from a cementing perspective, always strive to achieve the best balance between displacement efficiency and equivalent circulating density.

Conflict: This is a recommendation for designing and modeling of the well. It would be impossible to quantify “achieving the best balance.” There are many other factors that also need to be taken into account during the modeling and simulation.

RP-65 Part 4.3.1 Drilling Fluid Selection; adequate shale inhibition should be provided for aqueous mud systems.

Conflict: The term adequate is qualitative and arbitrary. "Should" is okay but "Must" being a requirement is not practicable. BOEMRE should not redefine the intent of reference documents.

RP-65 Part 4.3.1, Drilling Fluid Selection - Low-gravity or active solids should be effectively controlled, and adequate shale inhibition **should** be provided for aqueous drilling fluid systems. HTHP filter cakes **should** exhibit thin, low permeability

characteristics. Gel strength and low shear rheology at HTHP conditions **should** be low and non-progressive, but not at the sacrifice of drill cuttings transport or barite support.

Conflict: While the listed characteristics of drilling fluids can result in a drilling fluid that is more effectively displaced during cementing, it is not always the case that these characteristics can be met within the well conditions. Requiring all of this would create significant impediments.

RP-65 Part 4.3.2 Rheology; The rheological properties of some drilling fluids, synthetic-based fluids in particular, can vary widely with changes in pressure and/or temperature. Drilling fluid samples representative of the drilling fluid at the time of cementing should be tested with cementing fluids for rheological and chemical compatibility.

Conflict: This type of testing needs to be conducted well in advance of the cement job. Please clarify that a representative sample does not constitute a sample having the exact physical or chemical makeup but does possess the appropriate base fluid and additives anticipated at the time of cementing.

4.3.3, Hydrate Prevention - Pre-emptive measures **should** be taken to insure [sic] that hydrates do not form and do not become a safety/well control problem.

Conflict: Hydrates are not found in every drilling condition, they are mainly found in high pressure locations (e.g. deepwater), and so making this recommendation a requirement would introduce an undue burden for (at least) onshore applications of the document. Further, it is not possible to ensure that hydrates do not form, since they can occur naturally.

4.5, Close-tolerance and Other Flow Restriction Considerations - Close mechanical tolerances **should** be examined for mechanical (drift) compatibility with all components involved in the cementing operations including wiper plugs and associated operating components.

Conflict: This recommendation would become an ambiguous requirement as there is no guidance as to what are the failure criteria.

RP-65 Part 4.6; BOEMRE should refer to 4.6, Engineering Design, of RP 65-2 with regards to when to test cement. (4.6.3 for determining the “waiting on cement” or WOC time).

Conflict; in the current regulations, BOEMRE requires 8 to 12-hr periods, which could be detrimental if the cement is hydrating. The method described in 4.6.3 is specific to attaining a minimum compressive/sonic strength, which is a more reliable practice than just a time period.

RP-65 Part 4.6.2 Zonal Coverage Determination; It is important to evaluate which zone(s) have potential for flow in order to plan the cement job to achieve suitable zonal isolation. Ideally, such zones should be covered with cement slurries designed to prevent flow after cementing, and the cement placement mechanics should be designed

to maximize mud removal. Zones left uncemented may not flow in the short term if pore pressure is balanced by mud hydrostatic head.

Conflict: Total zonal isolation of all porous and permeable zones is in many cases not desirable for future well utility or annular pressure buildup mitigation in deepwater wells. It should not be a requirement to isolate all potential flow zones when these zones do not contain hydrocarbons and do not create a health or safety issue when they are not isolated. Many long intermediate & production casings in shallow water operations are tacked on the bottom to isolate normal pressure from abnormal pressure. However, normally pressured sands below the surface casing shoe are intentionally left exposed to allow future casing recovery. Clarify that all zones capable of flow do not have to be isolated by cement. However abnormal pressure must be isolated from normal pressure and hydrocarbon bearing zones must be covered by cement as stipulated under 30CFR250.421(d) & (e).

RP-65 Part 4.6.5.3; Fluid Type - In addition, all fluids used in the cementing operation **should** be compatible.

Conflict: Making this a requirement would unduly burden the operator. The intent of this 'should' is that all fluids that come into contact with each other should be compatible, not just every fluid used in cementing.

RP-65 Part 4.6.5.5, Mud Compressibility - For more accurate cement computer displacement simulations, mud samples **should** be tested at a laboratory under higher, more realistic confining pressure.

Conflict: It is not necessary to lab test under higher pressures if actual downhole pressure measurements can be used. Such lab testing can also significantly increase costs since there are only a limited number of labs outfitted with pressurized testing facilities.

Rp-65 Part 4.7.1, Slurry Design, General - Cement **should** be placed in the wellbore and provide good contact with the casing and borehole wall, prevent the formation of channels within the cement and prevent the invasion and propagation of fluid through the cement as it sets, and provide mechanical support. The cement **should** maintain its integrity throughout the life of the well.

Conflict: Cementing is not only done between the borehole and casing, it can also be done between pipe and pipe. It would be needlessly restrictive to impose only cementing between borehole and casing.

RP-65 Part 4.7.2 Lead & Tail Cement; Slurries are frequently designed with special properties and/or additives to control the flow. Lead slurries which are placed across "non-productive" formations having the potential to flow should be designed using the same criteria as slurries placed across the hydrocarbon bearing zones

Conflict: When running liners and cement is planned above the TOL, thickening time is often designed to allow setting a liner top packer, testing the LTP and circulating out the

long way in the event the LTP does not test, plugs don't bump or hold. This helps to avoid stuck pipe conditions, however the thickening time could be considered excessive from a pure zonal isolation point of view. Excessive safety factors avoidance should be limited to cement placed across potential flow zones.

RP-65 Part 4.7.6 Slurry Stability, Sedimentation, and Free Fluid; Slurries should be conditioned at temperatures encountered during placement and free fluid and sedimentation tests conducted at the temperatures to be encountered while static in the annulus.

Conflict: Free fluid and sedimentation tests conducted at the temperatures to be encountered while static in the annulus will lead to excessive testing of slurries. This infers all temperatures and not specific temperatures such as TD & TOC which should be adequate. Please confirm that testing is only required at TD and TOC for each type of slurry pumped.

RP-65 Part 4.7.8, Gel Strength - Additives for controlling other properties of the cement **should** be selected with control of gel strength in mind.

Conflict: Not every additive will impact gel strength, and occasionally, the properties being controlled by those additives may be more important to control than selecting it based on abilities to control gel strength.

RP-65 Part 4.8, Wellbore preparation and conditioning - Every effort **should** be made to minimize the time between completion of the hole interval and cementing when flow hazards exist.

Conflict: This recommendation is not auditable if made a requirement. It is not possible to quantify what “every effort” is.

RP-65 Part 4.8.2.4 Wiper Trip—Conditioning the Drilling Fluid after logging and prior to cementing, a wiper trip should be made to help stabilize the wellbore and remove any remaining cuttings.

Conflict: In many cases were production zones are not encountered, wireline logging may be performed to ascertain additional rock/fluid properties. The time to acquire this information may not be significant wrt to hole conditions needed for proper casing running and cementing. The Operator can assess the need to make a wiper trip based upon mud type and logging conditions. Current interpretation of this reference is BOEMRE mandates a wiper trip after logging operations. Please clarify that a wiper trip is not required after all wireline logging operations are complete and that the operator has the discretion on determining when a wiper trip is necessary to achieve the goal of getting casing to bottom and performing a successful cement job.

RP-65 Part 4.8.2.5 Rathole: Rathole beneath the casing shoe can lead to contamination of cement during placement, or mud can swap with the cement after placement. These can result in poor strength development, pockets of mud, or a wet shoe. Rathole length

should be minimized or filled with cement or some other type barrier materials to prevent this.

Conflict: The cost to minimize rat hole will be excessive in offshore operations. Many drilling assemblies are optimized for reasons which preclude putting a reamer immediately above the bit. In addition, the most important aspect when running casing in a deepwater operation or when a mandrel hanger is used is to ensure the hanger lands in the wellhead or profile. Please confirm the length of the Rathole will be determined by the Operator, however the Rathole shall be filled with a drilling fluid having a density equal to or greater than the cement pumped.

RP-65 Part 4.8.3.2, Centralizer Program - The recommended standoff **should** be determined from computer modeling of mud removal and will vary with well conditions (see discussion above in 4.6). Centralizers **should** be run according to an engineering design for optimum cementing results.

Conflict: There are times when experience and actual well conditions will supersede a computer model or theoretic engineering design in determining proper centralizer placement. While following these recommendations will help in developing an adequate centralizer program, it does not take the place of sound engineering practices and real in-situ conditions.

RP-65 Part 4.8.4 Conditioning After Casing is Landed: The drilling fluid should be conditioned until equilibrium is achieved.

Conflict: In many instances fluid conditioning may not be achievable once the casing is landed. Post landing fluid conditioning is desireable, however routinely not achievable once casing is landed. Operators may not be able to comply with this mandate from a practicalbe point of view. Operators should attempt to condition fluids and if possible take the time to do so. Should fluid losses occur, then cementing in less than desirable conditions must proceed without a request for approval from the regulator.

RP-65 Part 4.8.4 Conditioning After Casing is Landed: At a minimum, the hole should be conditioned for cementing by circulating 1.5 annular volumes or one casing volume, whichever is greater. Once the drilling fluid is well-conditioned (i.e. drilling fluid properties going in equal to properties at the flowline outlet), it should continue to be circulated until spacer and cementing fluids are pumped.

Conflict: In many instances fluid conditioning may not be achievable once the casing is landed. Post landing fluid conditioning is desirable, however routinely not achievable once casing is landed. Operators may not be able to comply with this mandate from a practicalbe point of view. Operators should attempt to condition fluids and if possible take the time to do so. Should fluid losses occur, then cementing in less than desirable conditions must proceed without a request for approval from the regulator.

RP-65 Part 4.9.3: Transportation and Storage of Cementing Materials - … Tanks **should** be physically swept out after a cement blend is stored in the tank

Conflict: Safety. Requiring a tank to be physically swept out will require workers to enter the storage tanks to sweep them out. Workers will be required to work in dusty, confined space entry work conditions, exposing them to health and safety hazards.

RP-65 Part 4.9.4; Mixing and Pumping - The cement spacer(s) and slurries **should** be mixed at the planned densities.

Conflict: Some variance in density will occur with field mixing equipment which is allowable, as long as the acceptable performance properties of the fluids are met.

RP-65 Part 4.9.4 Mixing and Pumping: The pumping of the cement job should be according to planned rates and volumes. The planned rates should be obtained from the output of a computer simulation (see 3.6.4.8). The computer simulation should determine maximum pumping rates allowable and mud removal efficiency at planned pumping rates

Conflict: Best efforts should be applied to actual pumping schedule to allow for upsets in equipment, changes if necessary from cement unit to rig pumps and vice versa if needed.

RP-65 Part 4.9.4 Mixing and Pumping: The cement unit should displace all squeeze jobs, liner jobs, stab-in jobs, and plug jobs. The rig mud pumps can be used to displace large casing jobs, although the cement unit should monitor and record the displacement pressures.

Conflict: This mandate (must instead of should) provides ambiguity in the pumps allowed for cement displacement. Operators routinely line up and test both the rig pumps and the cement unit regardless of which system is the primary displacement mechanism. Cement units often cannot provide the displacement rate necessary for the desired effect and thus the rig pumps are often used to displace. The Operator must be allowed to choose the most effective equipment to perform their work. Operators must designate the preferred equipment to perform the displacement and ensure that the equipment is properly calibrated to achieve the best possible volumetric efficiency and accuracy to achieve the primary goals of the cement job. Both the cement unit and rig pumps must be on line to provide backup systems to complete the job. Combined data acquisition at the cement unit during the entire cement job is required while backup recording to a drilling monitioring system is recommended.

RP-65 Part 4.9.5; implementing the Job Design and Adhering to Planned Procedures - All the '**shoulds**' in the section.

Conflict: One could unintentionally affect the integrity of the cementing job if the pumping is done only with consideration to the planned rates and volumes. While these should be considered and it should be done as close to these rates as possible, density control should not be compromised. Further, information from the computer simulation

should be used to determine the rates, in conjunction with sound engineering practices, not just with the computer simulation alone.

RP-65 Part 4.10.2 WOC; preferably, pressure testing casing should be done before significant gel strength has developed. However, such pressure testing will be limited by the pressure ratings of plugs, floats, cementing heads and other equipment. The pressure should be held on the casing for the shortest length of time required to accomplish the test.

Conflict: 30 CFR 250.423 requires a pressure test on casing for at least 30 minutes. RP-65 requires a transition time of less than 45 minutes. Thus performing the required casing test per the CFR will likely create a micro annulus that all are trying to avoid. Thus the CFR's and RP-65 are not compatible. Casing tests should be done once sufficient strength has developed to allow for blind shear ram testing or casing testing just prior to drill out. Alternatively a short test can be performed if the plugs bump (3-5 minutes) and if acceptable, this can be used in lieu of a 30 minute test.

RP-65 Part 5.2 Pressure Integrity Test Procedures; the following steps should be used when performing a pressure integrity test on a casing shoe.

Conflict(s): The exact steps and plumbing should not be mandated in the CFR's. Operators have requested not to drill additional hole when cement has not been drilled from the rathole. The rationale is that the purpose of the test is to test the cement around the shoe as well as the formation strength below the shoe. If cement did not occur in the rathole, then additional footage drilled should not be a requirement. Some operators prefer to pump into the casing or casing and drill pipe to reduce the friction drop through the system. In some cases, a PWD records downhole annulus and/or internal bore pressure and in these instances the information obtained from the PWD can be used to validate and/or augment the surface pressure readings. BOEMRE should not mandate the piping configuration to perform a PIT. The goal should be to minimize the effects of friction loss which could artifically inflate the PIT or LOT. Additionally, if PWD information is available, and a trip is made, then the actual LOT should be confirmed with downhole measurements.

RP-65 Part 6.2 Flow Prevention Practices Matrix; The sheet should be completed by the operator during the planning of the well to help identify areas needing improvement. Then, as each hole section is drilled and pipe cemented, the parameters relating to that section are scored. At the conclusion of each string, the scores for each parameter should be evaluated again and used as a post job evaluation. The sheet can be printed at each of these stages and placed in the well file. The scores, both by major category and the total can be compiled in a database and, with evaluation of flow, used for process improvement.

Conflict: The flow prevention practices matrix captures a lot of data, but fails to provide any information on a score value that constitutes a successful cement job. The information is at best arbitrary and does not really provide a measure of certainty. Please confirm that operators are required to prepare three cementing matrix sheets for each casing string; 1) Pre drill, 2) Pre Job

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once hole section is drilled and 3) Post cementing and to keep in their files. Also please confirm there is no intent to attain certain score level during any phase noted above.

III. §250.415(f)

Request clarifications on the level of detail and specific points that must be addressed in a written description of evaluation of the best practices included in API RP 65–2, many items are arbitrary or contradictory.

Clarification and publication of the specific information in a template or form to be evaluated by the Agency is requested. Evaluation guidance for consistency and acceptance should also be published by the Region for their District Offices.

IV. §250.416(d)

Specifications on exact requirements for the control system schematic should be clear. Confirm that the schematic of the control system includes location, alarms, control system pressure for BOP functions, BOP functions at each control station and emergency sequence logic.

V. §250.416(e)

Please confirm that the Operators will only be required to demonstrate shearing capacity for drill pipe (which includes workstring and tubing) that is run across the BOP stack. BHA components, drill collars, HWDP, casing, concentric strings and lower completion assemblies are excluded from this requirement.

Also, from an operational standpoint, shearing capacity with MASP should be modified to shearing capacity with mud hydrostatic pressure plus a conservative shut in pressure limit set by the Operator & Contractor where shut in is transferred from the annular BOP to Ram BOPE. At this point increased pressure in the cavity between the pipe rams and annular preventer should be eliminated. BOEMRE is reminded to review the Sintef Report on Deepwater Kicks which studied GOM kicks and concluded the actual shut in pressures were less than 2,500-psi.

BOEMRE should request the internal bore pressure shear capacity calculation to be provided at the limit of the BOP Control System and approval contingent upon MASP being less internal bore pressure limit. This would reduce the frequency of MASP/Shearing certifications required and allow BOEMRE to understand the reserve energy available for shear.

If the rule to Shear with MASP is not revised, then BOEMRE should clearly define the MASP calculation to be used for drilling, completion and workover operations.

VI. § 250.416(f)

Item 2, of this requirement infers that an inspection of the BOP system is required to ensure the system has not been compromised or damaged from previous service. Please confirm that SS BOP system is not compromised or damaged provided it can be function tested and pressure tested in the subsea environment where it will be in operation. Standardized pressure testing in the subsea environment without visual inspection fulfills the requirements of item 2 of this requirement. If it is mandated that a visual inspection between wells is required then the cost to implement of $ 1.2 MM is grossly understated in Docket ID BOEM-2010-0034, RIN 1010-AD68. A requirement to pull a BOP for a between well visual inspection would result in $ 5 - 15 MM per opportunity (opportunity defined as moving between wells without pulling to surface) and the total annual cost could be estimated by determining the number of occurrences per year.
3rd party verification that the BOP stack has not been compromised or damaged from previous service can be accomplished by successful subsea function and pressure tests without visual inspection. Between well visual inspections of the BOP internal components is not required.

VII. § 250.420(a)(6)

Will BOEMRE still check casing designs based on load cases that are not published? If so, will certified plans be rejected due to design reviews within the agency? Will Agency design reviews be done by Registered Professional Engineers (RPE)? If not, what will be the process for approval when an RPE approved design conflicts with the Agency? Will the Agency mandate a change and take the responsibility for that change?

BOEMRE has not provided specific guidance on what aspects of casing and cementing designs must be initially certified or guidance on triggers which would cause a plan to be recertified for continuance of operations. OOC provided those triggers to BOEMRE on October 12, 2010, (see table below) and requests they be accepted as the only triggers for plan certification. Currently BOEMRE is inconsistent in their requests for recertification and fearful of approving minor changes that have no effect on safety. Further, delays to operations resulting in additional operational exposure and safety risk are to be expected when the Agency requires arbitrary recertification when simple changes are required. The requirement for an RPE review for OCS operations may become a bottleneck if this requirement becomes a standard for all US operations due to the limited number of RPE's with well construction experience.

Task Considered	Basis for Recommendation

A change in casing weight, grade or connectors from the current certified plan to a lesser weight or grade of casing or to a connector with lesser performance capabilities and/or seal design. Upgrades in tubular performance properties and/or characteristics would not require recertification by a registered professional engineer.	Could significantly reduce design factors when performance properties are less than the certified plan.
Well deepening beyond current approved total depth.	Changes MASP and casing loads.
Sidetrack a well to a new BHL.	New well plan required and potentially different targets and pressures.
Add a casing string to a previously certified casing design which has been accepted by BOEM.	Fundamental change to the certified well design which could result in changes in MASP.
Eliminate a casing string from a previously certified casing design which has been accepted by BOEM.	Changes the design assumptions for the next casing string or changes the MASP.
Change from a liner to a long string, or vice versa.	Fundamental change in previously certified casing program should be recertified.
Integrity of previously installed casing is compromised.	Damaged casing may be de-rated for wear requiring recalculation of design factors or remediation.

VIII. §250.420(b)(1)

It is not clear if integral latching capability of casing hanger / seal assembly is acceptable or if a separate mechanism is required.

IX. §250.420(b)(3)

Clarification is requested for the dual mechanical barrier requirement to ensure the barriers are installed within the casing string and does not apply to mechanical barriers that seal the annulus between casings or between casing and wellhead. Acceptable barriers for annuli shall include at least one mechanical barrier in the wellhead and cement across and above **hydrocarbon zones**. Placement of cement can be validated by return volume, hydrostatic lift pressure or cased hole logging methods.

Industry best practices do not consider dual float valves to be two separate mechanical barriers because they cannot be tested independently and because they are not designed to be gas tight barriers. This regulation does not achieve the safety objectives of the Drilling Safety Rule.

X. §250.420 (c)

What is the design basis and acceptance criterion required for negative testing?

XI. § 250.420

Does the dual mechanical barrier requirement apply to just the inside of the casing or to both the inside and annulus flow paths? Our interpretation is the inside of the casing.

XII. §250.420, §250.1712, and §250.1721

Previous guidance/interpretation issued by BOEMRE said that deviation from certified procedures required contact with the appropriate District Manager. This is documented only in the guidance, and is not implicit in this part of the rule. We request that BOEMRE specify the kinds of variances that require this contact.

XIII. §250.423 (b)

Need definition or clarity around the term “lock down” and the requirement for locking down a drilling liner. Must all liner hangers have hold down slips? Normally conventional line hangers only have hang off slips to transfer the weight of the liner to the previous casing string. Once the seal is energized for a Liner Top Packer, it will hold pressure from below and above, but not all seals have slips to prevent uplift should the pressure-area effect exceed the weight of the liner. Requiring hold down slips on a conventional liner hanger increases the difficulty to fish the liner out of the hole; in fact it will lead to a milling operation.

Suggested Rewording:

(b); You must ensure proper installation of casing and liners during subsea operations as follows;

(1) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string which is landed on a mandrel hanger or profile.
(2) You must perform a positive pressure test on the seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liner.
(3) You must submit for approval with your APD, test procedures and criteria for a successful test.
(4) You must document all your test results and make them available to BOEMRE upon request.

XIV. §250.423 (c)

What is the definition of intermediate casing? The rule states a negative pressure test is required for intermediate and production casing. If drilling liners are set below intermediate casing is additional negative testing required?

The intent of this requirement is not clear. The magnitude of the negative test is also not apparent. Is the intent to test the entire casing, wellhead, liner top or the shoe? Surface wellheads are negative tested for each BOP test when the stack is drained and water is used for a test. If a negative test of an intermediate shoe is intended, then, what is the purpose since the casing shoe will be drilled out? **In general, negative testing should not apply to all wells and should apply if the load is anticipated and then not until such time it is needed.**

- Wells with surface wellheads should be exempt from negative tests unless the well is to be displaced to a fluid less than pore pressure and in that case the shoe, productive intervals and liner tops can be negative tested to the amount anticipated prior to or during the displacement. The requirement to negative test wells with surface wellheads should not be mandated since the well can be displaced to a fluid less than pore pressure under controlled conditions without risk of an influx getting in a riser.
- Additional guidance given by BOEMRE has indicated a desire to negative test all liner tops exposed in either the intermediate or production annulus on all wells with surface BOP equipment. This requirement is not consistent with the desire to improve safety since many liner tops are never exposed to negative pressures during the life of the well. Thus performing the test exposes personnel to additional exposure while tripping pipe to perform the test, risks the well by installing non-drillable test packers above the liner top during the test and will expose personnel to additional material handling requirements.
- Negative testing should be performed on subsea wells and wells with mud-line suspension systems where it is important to validate barriers prior to removal of mud hydrostatic pressure during an abandonment or suspension activity such as hurricane evacuation or BOP repair. Drilling or production liners tops should not require negative testing upon installation.
- The magnitude and duration of an acceptable negative test should be provided for consistency. Recommend negative tests on subsea wells to be equal to SWHP at the wellhead.

- Finally, the Agency has not provided guidance on when the test is to be performed. Testing upon installation is not advisable due to additional pressure cycles applied to the cement early in the development of its strength which could result in premature cement failure. Additionally, if a negative load is anticipated during operations, it is best to defer the negative test to assure well integrity is validated just prior to the intended operation

XV. §250.441

Requirement to pull BOP's after actuating BSR's should clearly state if only required when pipe is sheared (rather than actuated on empty cavity).

XVI. §250.442

What does "operable" mean for dual pod controls (100% functional and redundant)?

What does "fast mean" for subsea closure and what are the "critical" functions?

What will be competency basis for qualification of an individual to operate the BOP's?

XVII. §250.442(d), §250.515(e), §250.615(e)

Revise docket ID BOEM-2010-0034, RIN 1010-AD68 to reflect correct regulation. It should be 250.442 (d) instead of 250.442 (c).

XVIII. §250.442(e), §250.515(e), §250.615(e)

Revise docket ID BOEM-2010-0034, RIN 1010-AD68 to reflect correct regulation. It should be 250.442 (e) instead of 250.442 (c). The ROV crews should not be required on a continuous basis, this item needs to be revised to reflect the need for having a trained ROV crew on board only when the BOP is deployed.

XIX. §250.442(j), §250.515(e), §250.615(e)

Revise docket ID BOEM-2010-0034, RIN 1010-AD68 to reflect correct regulation. It should be 250.442 (j) instead of 250.442 (c).

XX. §250.442(i)

What is meant by <u>operate</u> critical BOP equipment; maintenance or activation of equipment?

XXI. §250.446(a) §250.516(h) §250.516(g) §250.617

The record keeping requested should be a responsibility of the Drilling Contractor. Many operations are short lived contracts and once the rig is released, the Contractor has no obligation to ensure the records remain on the rig. Drilling Contractors should be required to have a BOPE certification program complete with a certificate of compliance that is renewed every 3 to 5 years by a Certification Agency or Class Society. This will assure Drilling Contractors maintain their equipment to a higher standard on a routine basis. Certification documents for rental BOPE would also be used by the Operator or Contractor depending upon who is renting the equipment.

XXII. § 250.449(k), § 250.516(d)(9), § 250.616(h)(2)

Testing the deadman system when attached to a well Subsea is not recommended. If during the testing time the rig experiences a Dynamic Position incident, i.e. a drive off or drift off, the only options to disconnect from the well are acoustically (if acoustic system fitted), or with an ROV. Failure to disconnect in time could result in serious equipment damage, and/or damage to the well head. We suggest testing the Autoshear system Subsea, which tests the same hydraulic system as deadman, however Autoshear does not render your control system useless like deadman does.

XXIII. §250.451(i)

A successful seafloor pressure and function test of the BOP following a well control event also is an acceptable means of verifying integrity. Ram sealing elements would be compromised before damage to the rams themselves would be extensive enough to prevent successful shearing of pipe. Additionally, plugging an open hole that may be experiencing ballooning and gas following a well control event and pulling the BOP and riser present safety and operational risks that are likely much greater than proceeding with the drilling program using a fully tested BOP stack.

BOEMRE should request the frequency of damage to shear-blind ram cutting surfaces to establish a confidence level in the number of successful shears that can be accomplished by manufacturer and type. Newer technology like the LSF (Low Shear Force) shear-blind rams provide for more efficient pipe cuts and may reduce the incidence of ram cutter damage.

XXIV. §250.456(j)

Does this requirement only refer to the end of well during abandonment or at any time during the drilling of a well? There are times when mud weight is cut prior to drilling out a casing shoe due to exposure of weak formations or anticipated lost circulation. Would approval be required to cut mud weight in these circumstances? Consider that mud weight is cut just prior to drilling out the shoe in a controlled environment at which time

the entire system is negative tested with pipe in the hole at TD and BOPs are capable of shutting in the well if an when needed.

XXV. §250.616(b)(2)

During workover operations utilizing a subsea BOP, the Operator is currently required to pressure test the BOP every 7 days. This is inconsistent with requirements when utilizing same equipment for either drilling or completion operations where BOP testing is required every 14 days. Recommend revising all of §250.616(b)(2) to be consistent with §250.516(a)(2), which would include 14 day BOP test frequency and add the 7 day function test requirement.

XXVI.§250.1510

What is the definition of enhanced deepwater well control training? Will this require a new certification of well control schools?

Much of the prevention improvements have been implemented. With that in mind and realizing the risk of another blowout like Macondo is substantially reduced, BOEMRE should immediately allow the resumption of drilling operations in deepwater. On December 8th, Director Bromwich admitted that containment solutions have been prepared by Industry and in fact, were implemented on Macondo. Further, the State of Louisiana Department of Wildlife and Fisheries has opened (November 2010) ~ 98.5% of all fisheries and the FDA has found no seafood to be contaminated from the Macondo Incident. Therefore, the Agency should cease the requirement for an EA on approved deepwater Exploration Plans and Development Plans and allow companies to immediately resume drilling operations in the deepwater GOM!

Sincerely,

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