July 15, 2015

Department of the Interior
Bureau of Safety and Environmental Enforcement
Attention: Regulations and Standards Branch
45600 Woodland Road
Sterling, VA 20166

Re: Blowout Preventer Systems and Well Control, 1014-AAII

Via electronic submission to: http://www.regulations.gov/

To whom it may concern:

LLOG Exploration L.L.C. respectfully submits the following comments on the proposed regulatory changes to Blowout Prevention Systems and Well Control requirements in 30 C.P.R. § 250. The Bureau of Safety and Environmental Enforcement ("BSEE") announced these proposed changes on April 17, 2015, in a notice of proposed rulemaking entitled "Oil and Gas and Sulphur Operations on the Outer Continental Shelf-Blowout Preventer Systems and Well Control." which we will refer to in our response as the Proposed Well Control Rule or PWCR.

Based in Covington, Louisiana LLOG is the largest private oil and gas exploration and production company in the United States as measured by oil production. LLOG and LLOG subsidiaries hold 127 leases in the Gulf of Mexico and has both drilling and production operations on those leases. LLOG's operations will be severely impacted by this BSEE rulemaking.

Like all responsible offshore operators LLOG recognizes that offshore operations must be conducted safely and in a manner that protects the environment. LLOG has a long history of safe operations that have advanced the local South Louisiana as well as the national economy and the energy security of our nation. As noted in this response many of the requirements contained within the proposed rule will have an unintended adverse effect on the safety of personnel and will potentially cause more harm to the environment. In addition the estimated cost/burden attributed to many of the proposed requirements is substantially underestimated and need to be revised upward.

The following text highlights some of the proposed requirements that will have the greatest impact on LLOG, but there are numerous other proposed requirements that will have significant impacts as well. You will find below, detailed comments for the comprehensive list of these proposed regulations that will significantly impact LLOG.

A. <u>General LLOG Comments on the Proposed Well Control Rule.</u>

1. Safe offshore operations depend upon effective risk management in all aspects of well operations. Since the Macondo incident, LLOG has taken great strides to enhance personal safety and especially process safety. At LLOG this is best exhibited by the development and implementation of a comprehensive Safety and

Environmental Management System (SEMS). The LLOG SEMS is our demonstration of management commitment to safe operations, hazards analysis, emergency response and control, standardized well designs, operational procedures, management of change, risk management, mechanical integrity assurance, and fully captures how we successfully manage safety and environmental compliance.

2. LLOG is a founding member of HWCG one of the leading containment providers/groups in the Gulf of Mexico. The HWCG group and its members possess well control equipment targeted at prevention and containment and new procedures and tools for responding to oil spills. The combination of our refined SEMS programs coupled with our HWCG containment capabilities has created a model safety program in the Gulf of Mexico and beyond for conducting well operations and protecting the environment. The current proposed rules do not take these changes into account and establish prescriptive requirements that, in some cases, add rather than reduce risk. In total, these proposed rules will add an arbitrary economic burden that will significantly impact LLOG and reduce economic activity in the Gulf of Mexico and negatively impact U.S. offshore oil and gas production and resource recovery.

3. It is LLOG's strong view that the incorporation of guidance from several Notices to Lessees and Operators (NTLs), and the Final Safety Rule implemented by the then MMS and BSEE post Macondo have enabled significant improvements in safety, especially subsea well containment. In light of these advancements LLOG questions the need for the proposed revised provisions related to drilling, workover, completion, and decommissioning operations and the new requirements in the areas of well design, well control, casing, cementing, real-time well monitoring, and subsea containment. The proposed changes are significant and in fact have implications to ongoing operations at existing facilities and would impact facilities currently under development or construction as well as future operations.

4. LLOG strongly believes the proposed rule has failed in identifying a problem and building a case why the proposed rule will mitigate the problem. For instance, the discussion on the new safe drilling margins says BSEE wants to better define the safe margins, but it does not discuss why the current requirements are insufficient. LLOG's wells are being permitted and safely drilled under the current regulations. The proposed rule does not demonstrate how the new requirements were determined, or why these requirements will promote safer drilling operations on the OCS. The proposed rule refers to a recommendation from the Deepwater Horizon Investigation but does not discuss the investigation recommendation nor explain the recommendation's relevance to this proposed requirement.

5. In the past, when considering a complex new or totally revised subpart of existing regulations, MMS/BSEE recognized that a workshop or additional information sharing would provide a more comprehensive understanding of the impacts of proposed regulation. LLOG strongly recommends that BSEE arrange such workshops with each of the seven industry working groups that have analyzed respective sections of the proposed rules to correct fundamental flaws and allow constructive engagement of rules that are workable and effective. LLOG is

prepared to participate in such exercises and to bring forward concrete examples supporting some of the proposed changes and demonstrating why in other instances the current regulations are a better alternative to the terms of the PWCR.

B. <u>Well Design (Drilling Margin)</u>

1. Proposed changes to the drilling margin and lost circulation requirements will have significant consequences for LLOG. Under the current regulations and regulatory protocol governing well design and specifically drilling margin LLOG has been, and is able to safely execute the wells in our Exploration Plans (EP) and Development Operations Co-ordination Document (DOCD) plans. However, under the proposed regulations, many of our wells, especially redevelopment wells that need to penetrate depleted zones, could not be drilled.
2. The unintended consequences of the proposed drilling margins also need to be considered. The proposed restrictions on tight margin drilling will encourage deepening of the riserless sections to gain additional fracture gradient. This increases the potential for operators unintentionally drilling into over pressured water sands, creating difficult cementing conditions and increasing the probability of a poor structural foundation for the well due to poor cement jobs on the riserless intervals. Under such a scenario the potential risk has simply been shifted to the shallow casing strings from the deeper zones tight margin zones with no overall reduction in risk as a likely outcome.
3. The prescriptive tighter margin rules will also create conditions where pore pressures may be estimated to the low side and fracture gradients to the high side to facilitate design conditions that make wells "drillable" under the PWCR. This will in some cases hide the risks of tight margin drilling, creating scenarios where operators will be changing well plans to adjust to conditions that should have been addressed in well scenario planning.
4. LLOG has reviewed the inventory of projected development work and projects captured in its current EP and DOCD plans and evaluated those wells against the drilling margin and well design components of the PWCR. Over the next 5 years, 16 LLOG wells (12 sidetracks and 4 new wells) currently planned for development are unlikely to be designed and executed to meet the drilling margin requirements of the PWCR. These 16 LLOG wells could be executed in a safe manor under the existing regulations. All of the wells require drilling through depleted zones, however, the economic hurdle imposed by increased casing requirements, smaller (less productive or non-productive) production casing sizes or reduced evaluation capabilities due to smaller hole sizes, is highly likely to render these wells un-drillable or uneconomic. Over the next 5 years, LLOG projects the loss of these 16 deepwater wells results in over 1 billion dollars of lost economic activity (wells, flow-lines, etc.) and over 100 million Bbls in lost reserves. Ultimately over the remaining field life of these seven deepwater fields the loss of these wells represents a loss of over 6 billion in gross revenue to LLOG and 900 million in lost royalty payments to the federal government for wells LLOG would have drilled but did not due to the proposed changes in well design and drilling margin. The current risk based approach to well design and drilling margin and collaboration with regulators

has provided the protocol for LLOG to safely drill and complete tight margin wells resulting in benefits for LLOG, the federal government and the public.

5. If the drilling margin aspect of the PWCR is implemented as per the current text the number of wells that would be removed from LLOG's existing approved EP and DOCD plans amounts to what LLOG considers a "taking" by the federal government. Relative to the regulations when the leases were paid for and the exploration and development plans subsequently approved by the regulator and projects approved for execution, it is highly likely that LLOG can no longer execute a substantial portion of those plans due to the proposed rule changes to drilling margins. At a minimum, LLOG and other operators should be compensated for the lost revenue up to the full value of prior lease and royalty payments made for the affected leases.
6. The impact of just this one aspect of the PWCR to LLOG represents a fraction of the total impact to the GOM offshore industry as a whole. LLOG projects the total industry impact to be 20 times the impact to LLOG alone. This is a conservative estimate since there are other operators with more mature deepwater fields operating in the deepwater GOM, these fields have a higher proportion of depleted field drilling in their forward plans.
7. Going forward LLOG also anticipates utilizing managed pressure drilling technology, as well as dual gradient drilling technology to more efficiently and thoroughly develop the nation's offshore hydrocarbon reserves in areas currently open to exploration and development. The application of the proposed prescriptive drilling margin to these new technologies is likely to slow their development and restrict their use, handicapping the ability of operators to effectively manage these challenges. The end result will be a reduction in the capture of the nation's hydrocarbon resources from current areas open to leasing and more pressure to open new areas for development where the challenges associated with depleted field drilling are minimal. This outcome is in direct conflict with BSEE's charge to enable full development of the nation's offshore hydrocarbon resources in areas open to E&P activity. The industry's inability to deliver these projects in areas currently open to leasing will result in significant reductions in production of this nation's recoverable resources due to economically stranded reserves.
8. Reduced LLOG well activity also equals job losses in the suppliers and contractors LLOG hires to execute our work. The 16 wells LLOG projects will be lost over the next 5 years in terms of drilling activity is equal to the work scope (drilling and completions) associated with the initial development phase of one full deepwater project. LLOGs' most recent development Delta House provided at its peak over 10,000 jobs in over 171 companies in 15 countries, with the majority of that activity in the United States. This direct economic and job impact (or loss in this case) could more than quadruple when considering indirect economic impact.
9. The ten year assessment period is insufficient to fully assess the impact of these proposed drilling margin rules on OCS operations. As the rule would apply to development projects, and major capital equipment, which typically have lifespans

of 20-30 years and beyond, it is critical for the assessment to consider the associated later life impacts.

10. In summary, the associated economic impacts of the proposed drilling margin requirements have not been addressed and should be evaluated such that the full range of impacts is determined and reviewed. As described previously, the revised drilling margin requirements will prevent a large number of LLOG wells from being drilled or will add additional casing strings to meet the requirements. The impact to LLOG as a result of cancelled and modified wells must be considered in terms of reduced reserves, lower production and the associated decrease in jobs and revenue for the U.S. Treasury. For the subset of wells that could continue with the addition of extra casing strings, the Regulatory Impact Assessment must consider and include the additional time and risk associated with the incremental operations.

C. <u>Incorporation of API Standards by Reference-</u>

1. The incorporation of API RP 2RD Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) should be updated to the Second Edition, September 2013.
2. LLOG supports the incorporation of API Standard 53 (API 53), Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition November 2012. Through the incorporation by reference of API 53, those normative references also apply (in part or whole) in context, as specified within the Standard.
3. If BSEE intended to reference API Specifications 16A, 16C, and 16D for purposes other than their relation to API 53 then, those purposes should be stated specifically within the rule or the references should be removed entirely. Any incorporation of API 16A, 16C and 16D should be revised such that each edition is cited as incorporation by reference that is applicable to equipment manufactured 90 days after the publication date of the standard. This obviates the problem of the incorporation by reference rendering equipment presently in service, and serving satisfactorily, from being summarily declared obsolete, but also facilitates the incorporation by reference of new editions of the standards. Any additional requirements against a particular edition need to be justified.
4. The incorporation of API Specification Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, should be updated to the ninth edition, published June 2013 with an effective Date: June 1, 2014.

    Note: the eighth edition of API Specification Q1 is no longer an API/ISO document. The eighth version of Ql is significantly different from and is no longer a U.S. national adoption of ISO TS 29001:2010. The eighth edition of API Q1 is significantly different from and is no longer a U.S. national adoption of ISO TS 29001:2010. The eighth edition of API Q1 is no longer available from ANSI.

5. It was noted by BSEE that API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and

Natural Gas Industry, Ninth Edition, June 2013, incorporated by reference at §§ 250.730 and 250.806. All rigs in service currently utilize BOP components manufactured before the effective date of the proposed rule. Thus, a majority of these components were manufactured under a quality management system that was probably not certified to API Spec Q1 (as incorporated by reference in § 250.198). Therefore, LLOG strongly recommends BSEE grandfather existing equipment in use and in inventory prior to approval of the final rule as acceptable under the eighth edition of API Q1. If BSEE does not choose to grandfather existing BOP equipment in use as of the current regulations, then BSEE needs to include the cost of change in the final economic analysis of the proposed rule.

6. As cited in the document "BSEE-2015-0002-0002 – BSEE Economic Impact Analysis of PWCR", BSEE was "unable to determine the additional cost associated with the required certification by an entity that meets the requirements of ISO 17011 for quality management of BOP systems and BOP components". If the BSEE enforcement of the API Spec Q1 current edition (i.e. the Ninth) edition is rigorously enforced, it will result in replacing the BOP stacks on the existing deepwater rigs, at a cost of ~$30 MM per rig. <u>To LLOG this represents a cost of $60 MM not including rig time exposure to change out the BOP stacks</u>. Under LLOG's current long term rig contracts the operator (LLOG) is liable for rig equipment compliance to meet regulatory changes enacted during the contract period.
7. In the PWCR § 250.730(d) would require that quality management systems for BOP stacks be certified by an entity that meets the requirements of ISO 17011. ISO 17011 is an incorrect reference, which should be changed. LLOG recommends ISO/IEC 17021-1:2015 as the correct reference that should be applied to organizations which certify the quality of management systems to API Q1 requirements. The requirement to use ISO 17011 concerns the requirements for accreditation organizations for conformity assessment bodies. ISO/IEC 17021-1:2015 has been updated to focus on how certification services are delivered by a certification body, and as such is better suited to assess the effectiveness of operational and organization control by certification bodies.
8. The incorporation of ANSI/API Specification 6NISO 10423:2009, Specification for Wellhead and Christmas Tree Equipment, should be updated to the Twentieth Edition, October 2010, Effective Date: April 1, 2011, plus Errata 1-4 & Addendum 1-3. API Standard 6ACRA, First Edition, June 2015 Specification should also be referenced for completeness.
9. The incorporation of ANSI/API Specification 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Modified), Petroleum and natural gas industries- Downhole equipment- Packers and bridge plugs, should be updated to the Third Edition, April 2015. Incorporating the current edition of 11D1 ensures alignment of supplier/manufacturer documentation with the rule.

D. <u>Real Time Monitoring (RTM)</u>

1. LLOG endorses the requirement to have RTM capability. However, rather than a prescriptive requirement we support a performance based requirement to demonstrate how real time data is used to enable and enhance the overall safety of well drilling operations offshore. For non-drilling operations, the operator should include a risk assessment to BSEE that addresses the need for RTM capability in the APM (Application-Permit to Modify) permit for the proposed well activity.
2. The proposed rule preamble states that a BSEE forum was held in 2012 where one of the 4 panels addressed real time technologies that aid in diagnosing and response to kick detection. Review of the transcript of that panel discussion reveals that the panel did not address the issue either in the presentations by panel members or in the follow-up Q&A portion of the panel. LLOG's position on the issue of automated real time kick detection and response is that the technology has experienced limited development, and that proven applications of such technology do not exist. Given the complexities of the downhole geology and formation stress states (pore pressures, fracture gradients, etc.) coupled with hole cleaning dynamics and the range of variability in wellbore circulating conditions, successful development and proven application of automated kick detection systems/software is not imminent. Thus, LLOG's focus is on ensuring trained and competent operating staff and operations supervision is in place onsite offshore.
3. The proposed rule preamble also states "The proposed rule also would reduce the probability of oil spills, and the provisions with the highest costs to industry (such as real time monitoring of well operations and alternating BOP control station function testing) will have the largest impact on reducing the risk of spills." LLOG respectfully challenges this statement. LLOG staff with experience in manned real time monitoring centers and studies evaluating their impact on safety contends that there are no known documented examples where manned real time monitoring centers reduced incidents and increased safety. LLOG respectfully requests the BSEE to make public the data indicating manned real time monitoring centers have increased safety and reduced incidents.
4. The proposed rule concerning Real Time Monitoring requirements implies a drive to shift operational decision making away from Operator's rig site personnel. LLOG maintains this exposes the operations to increased risk levels. During any given operation, the onsite personnel have the best understanding and most complete picture of the current operation, key risks and critical considerations. In addition, their experience in active operations provides them with the judgment to make effective real-time decisions within the bounds specified by the LLOG SEMS and operating procedures. This responsibility includes full control of the operations and full authority to stop activities at any time. Shifting this authority and decision making capability away from the well site does not increase safety.
5. As a general rule, operators that use shore-based operations centers do so to <u>assist</u> personnel on the rig with monitoring of specific functions of the drilling operation, not to assume control of operational activities. In some instances operators have elected to deploy remote staff in real time monitoring centers versus utilizing additional operational oversight/assistance onsite offshore. LLOG currently utilizes

virtual real time monitoring AND has elected to provide additional onsite mudlogging staff to assist the LLOG onsite supervision in monitoring the drilling operation. Utilizing this protocol provides LLOG with superior real time monitoring capability equal to anyone in the industry. Moving the onsite real time monitoring assistance to an onshore offsite location reduces safety.

6. LLOG and other operators should have the flexibility to demonstrate a performance-based approach to RTM rather than follow a prescriptive requirement. The demonstration should be included in their Exploration Plan (EP) or Application for Permit to Drill (APD) and should describe what functions of critical rig systems will be monitored during rig operations. These functions will vary with the rig used and the equipment on board the rig, as well as the location of any support facilities ashore. It should be clear to BSEE that it remains the primary responsibility of the onsite rig personnel to monitor information from drilling operations on a 24/7 basis and to take appropriate actions without waiting for direction from a remote shore base. Utilizing real-time data centers and shore base decision making is likely to lead to a decrease in offshore personnel's responsibility and accountability which is critical to maintaining safe operations and responding to emergency situations. In times of communication interruptions or significant offshore events (well control, station keeping difficulties, vessel collisions, equipment failure, etc.) there is generally insufficient time to interact with shore base command centers to plan a response. It is these critical moments that onsite real time monitoring and offshore supervision are key, and effective oversight can only be maintained if the primary decision making remains focused offshore.
7. To ensure offshore personnel are equipped with the necessary knowledge prior to specific operations, a range of preparatory engagements are held with the shore base engineering and operations support teams or through on-site assistance. In these engagements, the key risks and critical steps are discussed to prepare the offshore team for the upcoming operations, including discussion of potential risks and appropriate responses. This approach should be maintained for all active drilling operations.
8. It is LLOG's understanding that BSEE has contracted the National Academy of Sciences Transportation Research Board (NAS) to advise the agency on the use of real-time monitoring systems (RTM) by industry and government. The NAS is to determine what measures could reduce the safety and environmental risks of offshore oil and gas operations and to make a recommendation on whether RTM should be incorporated into BSEE's regulatory scheme. The National Academies conducted a RTM workshop in Houston on April 20th 2015. LLOG presented its concerns with the RTM provisions of the proposed rule and specific request for a performance based RTM requirement at this event. LLOG also expressed security concerns associated with real time transmittal of data from critical rig well control and positioning systems. The PWCR requires LLOG and other operators to make that data stream available to the federal regulators upon request. LLOG assumes this means real time access when requested. Such access poses a security risk/exposure to "hackers". Will the BSEE have security protocols in pace to ensure the federal access does not open up added security risk to the control of these critical rig

systems? Cyber security firms currently under government contract have indicated to LLOG such access could provide an entry portal for "hackers" to access actual control systems via system software. These concerns were relayed to the National Academies by LLOG at the workshop. The final report of the National Academies should address these concerns and be fully considered by BSEE and the public before any rulemaking on RTM is finalized.

E. **Casing and Cementing**

1. The new proposed casing and cementing requirements at §250.420(c)(2) will: 1) have unintended consequences; 2) are not technically sufficient; 3) may prohibit the judicious use of unweighted pre-flushes as a tool for equivalent circulating density (ECD) management; and 4) is not technically necessary.
2. Unintended consequences:
   - Increasing mud weight to replace pressure reduction during cement hydration is likely to result in the need for increased spacer density and cement slurry density in order to maintain density hierarchy needed for effective mud removal (API Standard 65-2, 2nd Edition, Section 5.6.5.2).
   - Increasing mud weight to replace pressure reduction during cement hydration increases the risk of lost circulation during cement placement and may result in failing to attain the cementing objective of the required top of cement in the well.
3. Computer simulations for a group of actual wells demonstrated that wells which can be successfully cemented using current practices cannot be properly cemented with higher fluid density.
4. Is not technically sufficient to simply specify the use of a weighted fluid to maintain a hydrostatic pressure overbalance (i.e. increased pressure). Although increasing the pressure applied to the cement slurry (whether from increased fluid hydrostatics or through the post-cementation application of annular pressure) increases the critical gel strength value by increasing the initial overbalance pressure (equation in API Standard 65-2, 2nd Edition, Section 5.7.8), this pressure is not transmitted through the cement slurry during the slurry's Critical Gel Strength Period (transition from the Critical Static Gel Strength to 500 lbf/100ft2 gel strength) (SPE11206 and SPE 11416 and described in API Standard 65-2, 2nd Edition, Sections A13 and A14).

   Therefore, additional pressure may not be sufficient in the absence of a cement slurry design that properly addresses the Critical Gel Strength Period.

5. The additional pressure requirement may prohibit the judicious use of unweighted preflushes as a tool for equivalent circulating density (ECD) management.
   - In some wells, pumping a weighted spacer followed by a lighter weight turbulent-flow flush has been used to manage ECD and mitigate the potential for lost circulation. In such cases, the hydrostatic pressure from the weighted spacer ahead compensates for the reduced hydrostatic pressure

from the flush and maintains the overbalance pressure in the well. The proposed rule may prohibit optimum ECD Management

6. Is not technically necessary.
    - The entire purpose of API Standard 65-2, 2nd Edition was to describe method(s) of isolating potential flow zones. API Standard 65-2, 2nd Edition is already incorporated into the regulations by reference.
7. In summary, proper slurry design coupled with proper mud removal described in API Standard 65-2, 2nd Edition is sufficient to meet the goal of the proposed regulation.

F. BOP Equipment

1. Related to BOP equipment, there are several high impact items identified. Most notably is the overly prescriptive language on certain requirements; accumulator sizing, testing, BOP configurations, providing access to facilities and Quality Assurance/Quality Control (QA/QC) oversight imposed on the lessee. The rule does not take into consideration that rig equipment manufactured and installed, in almost all cases, occurs before the lessee is identified or has contractual obligations.
2. Unrealistic implementation timeline - Numerous provisions of the proposed rule are predicated on the availability of BSEE-approved verification organizations (BAVOs) to perform verification and/or certification services in advance of the submission of an APD or APM or a regulatory deadline. There is no guarantee that such services will be available. Even if available, the implementation dates do not allow for a reasonable period of time between the initial approval of a BAVO and the effective date of the rule. LLOG has strong concerns that his aspect of the PWCR will be implemented with the potential risk of permit delays and idle rigs and related support services at a cost of $750,000 to $950,000/per day in time based cost exposure.
3. Except as where specifically specified otherwise, BSEE has proposed an effective date of 3 months following the publication of the final rule, this presents the following difficulties:
    - As noted above, BAVOs cannot be "approved" until after the effective date of the rule. Any provision of the rule that requires action by a BAVO cannot be in compliance until the BAVO has been approved. Accordingly, as per §250.731(c) and (d), there will be considerable delay between the effective date of the rule and the date at which it will be possible to submit an APD or APM. LLOG strongly recommends BSEE reevaluate the timing for implementation of BAVOs for the approval of rig equipment installations and rig equipment testing. The BAVO approval process should only be required after BSEE has verified BAVOs of sufficient number and capacities are in place to provide verifications to operators and rig contractors.
    - Most existing surface stacks are not equipped with hydraulically operated locking devices. Compliance with the proposed§ 250.735 (g) would obviously require time to complete the up-front engineering services and

upgrade of the stacks prior to the date where such stacks must be identified in an APD or APM.

4. Imposition of requirements beyond those addressed in API 53, the proposed requirements which exceed the provisions of API 53, are unnecessary and may not improve safety.
5. Implementation of the proposed rule would require more accumulators with larger volumetric requirements leading to larger and heavier BOP stacks than are presently in use.
    - It is LLOG's contention that heavier BOP stacks will result in unintended negative consequences related to handling, deployment and operation of the BOPs and will impact well construction design with even further limitations to re-enter existing wells.
    - Some MODUs do not have the space to install the additional surface BOP accumulator bottles that would be required. Creating this space will require extensive rig modifications and extended periods out of service.
    - The additional required associated equipment (e.g., larger fluid reservoirs, additional pumps, and additional accumulator bottles) is also problematic. Unnecessarily large accumulator capacities may not be practical and could result in a decision to remove some other BOP well control components and thereby reduce redundancy for many vessels. Such well control components are on BOPs stacks that exceed the BOP functionality requirements of current regulations as well as the PWCR.
    - Clarification is needed regarding the ability to use an independent accumulator bank for subsea hydraulic power. Does the hydraulic power have to come from the BOP Stack bottles themselves? LLOG recommends that, in the event that BSEE holds firm on the new hydraulic controls power requirements, operators may use alternative options such as the use of an independent accumulator bank (or SAM - Subsea Accumulator Module) for the hydraulic power. These SAMs are set on mats beside the BOP on the ocean floor. The SAM system can be used in conjunction with the ROV flying lead to engage each new required control function in an intervention scenario. Alternately, a hosed connection can be made from the Subsea Accumulator Module to the BOP Stack once deployed. This option could/may require a new control panel (functions would still be activated by the ROV – without the use of the flying lead.) The flying lead system would continue to provide the secondary means activating BOP functions. LLOG recommends that BSEE afford operators the option to implement the accumulator bank solution if the proposed accumulator requirements are not modified.
    - TIMING - When must this revised accumulator requirement be met? It is LLOG's interpretation that these new rules would go into effect within 3 months of publication. LLOG recommends that this requirement, if maintained, should be on a 5 year deadline.

- The BSEE estimates the cost of the increased surface accumulator volumes to be $2.8 MM to industry for a fleet of 90 deepwater rigs. LLOG estimates a material cost of approximately $1.8 MM and $5.2 MM for our two long term deepwater contracted rigs. Adding in rig time costs of ~$500 & $750 per day and the cost could triple to $5.4 and $15.6 MM, just for LLOG's two current contracted deepwater rigs. LLOG respectfully asks BSEE to recalculate the industry cost of compliance for this aspect of the PWCR.
- Lastly, the increase in cost related to Paragraph 250.743 (a)(3) regarding increases in accumulator capacity requirements located subsea, LLOG expects an additional cost of approximately $ 1 MM and $2.4 MM per vessel if accumulator bottles have to be permanently attached to the BOP stack (includes materials only. Installation, testing, commissioning and structural modifications not included)
- Additional cost considerations are outlined in the APPENDIX

6. Expanded subsea testing of the Deadman/Autoshear, beyond current practices and what is defined in API 53, could increase risk of harm to personnel, negatively impact the environment and cause unrecoverable damage to the rig or well. LLOG feels the additional risk is especially applicable to certain "older" BOP models where to "kill" all power to the BOP control pods for the test results in unnecessary risk to the system.
7. Restrictive language on the placement or configuration for the installation of Blind-Shear Rams could lead to loss of additional pipe rams in order to accommodate the requirements prescribed in the proposed rule. LLOG feels BSEE should conduct and publish a formal risk assessment to determine the guidance for placement of all rams.
8. The requirement in the proposed rule to ensure that BSEE has access to any facility and prior notification of any shear testing is unobtainable. "You" as defined in the proposed rule applies to the lessee. The lessee is not always aware of R&D being performed by individual companies or manufacturers. The lessee does not have the contractual authority to grant BSEE access to facilities not under the lessee's control. LLOG recommends dropping this requirement or limiting it to rigs or facilities controlled by the lessee.
9. Requirements within the proposed rule relating to QA/QC oversight by the lessee is unobtainable, as the vast majority of equipment designs, manufacturing and testing are completed before a contractual obligation is reached between the purchaser of the equipment (typically the rig contractor) and the lessee.
10. Barriers to Trade - The Bureau's regulatory structure present an unacceptable technical barrier to trade.

    - Neither equipment manufacturers nor equipment owners have access to BSEE's approval authorities under 30 CPR §§250.141 and 250.142, except through an oil company operator (i.e. lessee) and the APD or APM process.

- When granted, approvals of alternative compliance or departures are limited to an individual APD or APM. A request for approval of an alternative to the basic design of a piece of equipment (e.g., to an element of design of an API Specification for a BOP element, or for approval of an alternate quality assurance program) must be repeatedly submitted over the life of that equipment, with the unacceptable possibility of a different outcome with each submittal.

11. Regarding lessees adhering to Original Equipment Manufacturers (OEM) maintenance plans as noted in API S 53, LLOG requests a modification. In order to prevent a conflict of interest on the manufacturer's and equipment provider's part, LLOG recommends that Original Equipment Manufacturers (OEM) maintenance plans can be modified by the Drilling Contractor via documented risk assessments. The drilling contractor's subsea personnel on board each respective rig typically have the best knowledge of the service, cycles and environment that the stack has been operated in. Usage related maintenance vs. time related maintenance should always be considered. The OEM has a vested interest in selling consumables and in cases where service cycles are limited a time based changing of parts is often not warranted and the wear and tear on BOP stacks related to breaking and replacing components can instead add system risk to simply change out a component that has experienced limited use.

G. <u>Containment</u>

1. At this point it is worthwhile to note that the HWCG consortium (of which LLOG is a member) is engaged in active conversations with Wood Group Kenny ("WGK") providing input to a BSEE initiative to develop meaningful guidelines for capping stack inspections and recommend to BSEE how capping stacks should be incorporated into 30CFR250. LLOG, like HWCG, is concerned that WGK's effort appears to be wholly disconnected from the proposed rulemaking. If the WGK initiative is disconnected from the PWCR the outcome may be contradictory to the agency's proposed rule. We urge BSEE to coordinate these efforts and thereby avoid duplication and confusion.
2. Cap and Flow - The proposed requirements related to containment appear to assume that a cap-and-flow system is required in addition to a cap-and-contain system to control a source at the seafloor. If the operator's evaluation using the BSEE-endorsed well containment screening tool indicates a wellbore can withstand a complete shut-in while maintaining full integrity, then cap-and-flow well design and equipment should not be required for that permit. Cap-and-flow well design and equipment should be required for permit approval if the wellbore integrity analysis indicates loss of wellbore integrity when attempting a complete shut-in.
3. <u>Costs</u> - In the rule's preamble and Initial Regulatory Impact Analysis, RIN: 1014-AA11, BSEE requested feedback on whether or not its estimate of an incremental $80,000 per year cost to industry for capping stack tests was reasonable. Based on LLOG's shared expense of HWCG's four-year existence, BSEE has grossly under estimated the cost. BSEE used a cost of $5,000 per capping stack test. HWCG's

total cost of the most recent pressure test was eight times that amount, while the most recent function test was just over six times more.

4. In the BSEE cost analysis it is stated: "The baseline refers to current industry practice in accordance with existing regulations, industry permits, DWOPs, and industry standards with which operators already comply. Impacts that exist as part of the baseline were not considered costs or benefits of the proposed rule…the analysis excluded activities or capital investments that are required by existing regulations or as conditions for permit or DWOP approval." The implication is that the substantial capital invested in establishing the two existing BSEE-accepted deep-water well containment consortiums (HWCG LLC and Marine Well Containment Corporation) were not included as a cost in the analysis. However, the BSEE cost analysis correctly states that there is no capping stack testing requirement in the current regulations and thus the pressure testing and function testing of capping stacks would be incremental to the current requirements. Including the costs to test the capping system(s) but not the cost of the systems and organizations to run these systems is inconsistent. Since the requirement for capping stacks has, until this PWCR, not been in any regulations governing well activities, the cost to provide and test these systems needs to be included in the PWCR cost analysis. LLOG requests BSEE revisit the economic analysis and include the HWCG/MWCC investment which is a de facto requirement for APD approval. The LLOG cost to be a member of the HWCG consortium was an initial fee of $2,000,000 and an annual fee of $2,500,000. On a go forward basis this is a minimal cost of $25,000,000 over the next 10 year period when per well fees are included.
5. Shallow Water Containment - In the preamble of the proposed rule, BSEE solicited comments on whether source control and containment requirements should be applicable to wells drilled in shallow water. Current subsea containment requirements only address deep-water GOM drilling operations using a subsea BOP or a surface BOP on a floating facility. The equipment available for a deep-water source control event may not be suitable for a shallow-water response. Shallow water requirements will vary depending on scenario and would utilize different resources such as divers, over-shots or other industry equipment available in the GOM. Any additional requirements for fixed bottom drilling operations should be addressed through a separate rulemaking process due to the unique risks and work environment which utilizes different resources compared to deepwater operations addressed in the PWCR.
6. Additionally, BSEE should be aware that the Offshore Operators Committee has formed a Shallow Water Source Control Workgroup committed to working with BSEE on the topic. HWCG suggests that the matter be fully outlined in that forum before an attempt at rulemaking is attempted.

H. **Inspection and Mechanical Integrity**

1. The revised requirements in the proposed rule on certification are unnecessary and do not improve safety and in some cases reduce safety and could cause more harm to the environment. Currently, LLOG and the industry successfully utilize

certification and verification processes that balance the availability of existing infrastructure while managing safety and reducing risk. The processes in use today by LLOG and LLOG contractors provide the ability to utilize a staged approach for equipment certification on a component basis which allows rigs to maintain ongoing safe operations utilizing reliable, certified equipment.

2. History and data supports the position that inspection and mechanical integrity processes used today have proven to be safe and effective, in contrast to the certification approach in the proposed rule which will require all in-service equipment to undergo additional certifications and be completed by a common due date. <u>This will lead to rigs being out of service for extended periods of time due to the inability of existing certification infrastructure being able to meet a common due date</u>. The proposed certification scheme could result in unintended consequences that neither reduce risk nor improve safety, such as the degradation of equipment during extended inspection durations. A rig out of service (or rigs on downtime due to recertification of entire systems to meet the “common date”) adds greatly to operator’s costs and scheduling delays. With rig operating spread costs of up to 1 million dollars a day BSEE’s estimated annual cost to industry of only $4.3 MM is substantially underestimated and is closer to the per rig cost versus per industry costs.
3. Further, expansion of the certification process dilutes resources and focus, which may result in increased risk.
4. BSEE has complete control of the permitting process and the obligation to withdraw an existing permit or not approve a new permit from an operator if they do not have effective tools and processes to manage risk. BSEE's ability to evaluate upcoming and ongoing operations and effectively manage the permitting process (with a primary focus on the operator's ability to employ effective risk management processes) will result in safer and more robust operations. These processes are currently covered by API RP 75 and the BSEE Safety and Environmental Management System (SEMS) rule.
5. LLOG requests that expansion of the current BOP and other rig equipment certification process be removed to avoid these negative consequences.

I. <u>Certification by a BSEE-approved verification organization (BAVOs)</u>

1. There are several places in the proposed rule adding new requirements for certification by a BSEE-approved verification organization or BAVO. Currently no BAVOs exist, which is likely to result in delays/shutdowns upon the effective date of this rule.
2. Requirements for certification by a BSEE-approved verification organization should not go into effect until 12 months after the initial BSEE-approved verification organization list is published. Additionally, Industry should be consulted to help identify BSEE-approved verification organizations to help ensure that qualified third parties are being used.
3. BSEE should establish a protocol for resolving disputes between BAVOs and operators and contractors concerning interpretation of the BSEE regulations.

4. BSEE should address what liability and accountability BSEE will assume as a result of requiring BAVOs.
5. BSEE should clarify and publish their audit process that will be used to assure lessees of the competency of their BAVOs.

J. <u>Economic Analysis</u>

1. The ten year assessment period is insufficient to fully assess the impact of these proposed rules on OCS operations. As they would apply to development projects which typically have lifespans of 30-40 years and beyond, it is critical for the assessment to consider the associated later life impacts.
2. The rule and the associated economic analysis fail to fully capture the cost impact to operators and also fail to acknowledge that individual contractors, not "the industry" and not operators or lessees (i.e., oil companies) will also bear many of the costs associated with implementation of the rule, particularly those associated with modifications to blowout preventer systems. Contractors may be able to recoup some of these costs in accordance with the terms of the individual rig contracts, or (over time) through increased rig rates, but this is by no means guaranteed.
3. Implementation of the rule has the potential to disrupt normal contracting practices, especially for drilling rigs. The numerous provisions of the rule that impose requirements beyond those reflected in API Standard 53 are unlikely to be accepted in the international marketplace: This will limit the number of Mobile Offshore Drilling Units (MODUs) readily qualified to be contracted for operation in areas under BSEE jurisdiction such as the US Gulf of Mexico (GOM). As a result, the supply of available drilling units will be reduced resulting in increased rig dayrates for US GOM operations. These costs have not been addressed in the proposed economics.
4. For domestic operators such as LLOG that only operate in the US Gulf of Mexico OCS, the economics associated with higher costs will be magnified. The timing of rig contracts and rig availability will be affected as operators with non-US offshore operations will have the flexibility to utilize non US compliant rigs outside of the US and restrict the higher cost US compliant rigs to their US operations. LLOG could be in an economically disadvantaged position where its' US based rigs may need to be taken out of service in order to upgrade equipment as provisions of the rule are phased in (e.g., as with the proposed §250.734(a)(l)), or during periods when significant compliance costs or operational uncertainties may be incurred (e.g., as with the proposed §250.739(b)).
5. Retrospective application of manufacturing specifications (e.g., API Spec. 16A, Spec. 16C, and Spec. 16D) to existing equipment effectively prohibits the use of such equipment. Summarily declaring such equipment as unfit has not been justified; it has also not been considered in the economic analysis.
6. Although a broad range of costs have been considered in the RIA, there are a number of potential cost impacts that have been overlooked. An underlining assumption made in the analysis is that the current operating accepted practice is equivalent to the "no action" baseline (for example source control containment

equipment provided by MWCC and HWCG). However unless the accepted practice is already a minimum regulatory requirement, the cost of that practice should be included as an incremental cost. In the case of well containment services and equipment that are now accepted practices but not regulatory requirements (but will become required under the PWCR) these costs are considerable with total well containment coverage costs averaging between $1.0 to $10.0 million per well depending on the provider. In addition, potentially significant cost impacts associated with retrofitting existing facilities (i.e. dual bore risers on existing TLPs and SPARs) have not been addressed. If this is a result of an intended "grandfather" scheme, then such clarifications should be included in the proposed rules.

7. In summary the BSEE has significantly under estimated the cost of compliance to the PWCR by 1-2 orders of magnitude. BSEE should reevaluate these costs as well as formally justify the expected benefits of the PWCR.

K. <u>Probabilistic Risk Assessments (PRA)</u>

1. Within the preamble there are request for comments related to the practice of utilizing (PRA) modelling for use in those operations incorporated within the proposed rule. Preliminary investigation indicates that PRA is used extensively in the nuclear industry and has proven to be adequate for modelling those operations successfully. However, given the dynamics within well operations affected by the proposed rule, PRA is not likely to achieve the desired outcome. The PRA approach establishes a given value or number for a related task or set of tasks; however, a certain change to a similar task might not change the PRA value, therefore providing false positive and false failure results. In addition, the nature of offshore oil and gas activities necessitates more human factors than other industries, which reduce the applicability of PRAs.
2. LLOG strongly advocates for a Risk Assessment model that includes a Multiple Physical Barrier Approach (MPBA). This model best follows the dynamics incurred within the industry for well operations where one change may be identified but could be overlooked within the PRA model that is proposed. LLOG prefers a risk assessment model where the potential hazards - most commonly hydrocarbons under pressure in either the reservoir or surface equipment - are properly managed via a multiple barrier approach.
3. The MPBA is a simple depiction that identifies and manages the barriers during the course of dynamic operations. It has the best chance of reducing a false sense of operational security.

L. <u>Applicability to Existing Facilities and Equipment</u>

1. It is not clear whether existing facilities will be "grandfathered in", or whether they will have to comply with the new rule (which would be a very expensive requirement). Similarly, it is not clear whether or not existing equipment already under construction will have to comply with the new regulations in the event that the new regulations are finalized or become effective prior to startup of new facilities (this may not be possible without a significant delay and associated costs).

For LLOG, Safety is a core value that enables all of our operations. Maintaining a safe operation is what we consider to be "our license to work". We are fully committed to safe operations and support effective regulations in the area of blowout preventer systems and well control. We appreciate the opportunity to comment on this very important rulemaking and are available for further discussions at your convenience. Please feel free to contact us with any questions.

Sincerely,

Joseph M. Leimkuhler
Vice President - Drilling

<u>Appendix 1 - New Accumulator Volume Calculation & Impact</u>

REFERENCES
Paragraph 250.735 (a) outlines the new requirements for surface accumulator system
Paragraph 250.734 (a)(3) outlines the new requirements for accumulator capacity located subsea:

<u>Requirement for Surface Volume:</u>
1.5 times the required accumulator volume for ALL annulars, pipe rams and failsafes to be functioned closed with operator pressures equal to or above what would be required by closing on MASP, with (a) blind shear ram being the last in the sequence. To be completed without the use of pumps

<u>Requirements for Subsea Volume:</u>
Volume Sufficient to close 2 shear rams (under MASP), failsafe valves, one pipe ram (under MASP), and unlatch LMRP connector and LMRP stabs.

<u>EFFECT ON LLOG - COST SUMMARY OF BOP UPGRADE</u>
The approximate cost of the required upgrades per drilling contractor study:

A) 7 Cavity Cameron BOP Stack on rig #1:
- Surface volume increase requirement: $ 1.8 MM US (this cost includes materials only [bottles, pumps and piping]. Installation, testing and commissioning not included)
- Subsea volume requirement: $ 1.0 MM US dollar (this cost includes materials only, installation, testing, commissioning, and structural modifications not included)

B) 7 Cavity NOV BOP Stack on rig #2:
- Surface volume increase requirement: $ 5.2 MM US (this cost includes materials only. Installation, testing and commissioning not included)
- Subsea volume requirement: $ 2.40 MM US dollar (includes materials only, installation, testing, commissioning and structural modifications not included)

NOTE 1: Physical feasibility of additions of bottle onto the BOP Stacks is doubtful due to space and weight limitations.
NOTE 2: These costs do not include any idle rig time associated with the modification. Rig time costs for rigs under contract are to be borne by the operator and are estimated conservatively at 3 times the material costs.

Appendix # 2: ROV INTERVENTION CAPABILITIES UPGRADE:

Reference is made to Paragraph 250. 734(a)(4): When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; Additional requirements: The ROV must be capable of performing critical functions including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).

EFFECT ON LLOG – COST SUMMARY OF UPGRADE:

Rig #1: Based on the upgrades we have carried out proactively on Rig #1 with the Master ROV Intervention Panel ,we now only have the ability for close functions (not close + open as stated above) . This would require approx. 34 more functions .

APPROX. COST : $ 800 K to $ 1 MM

Rig #2 - We will need to carry out some modifications and add circuits to Rig #2 (similar to the modification carried out on rig #1 and add open circuits as described above)

APPROX. COST : $ 1.5 MM X 2 : $ 3 MM US

NOTE 1: Surface testing of these new ROV functions would add at least 12 hours to total test time prior to BOP deployment. Which equals a per well cost of and additional $500,000 to $650,000 per well.

NOTE 2: Additional ROV Functions adds more maintenance, single point failures and leak paths.

Appendix # 3: SEQUENCING FOR MAXIMUM SHEARING EFFICIENCY

Reference is made to Paragraph 250.734(a0(6)(v)and (vi):

(v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency.

(vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.

EFFECT ON LLOG – COST SUMMARY OF UPGRADE:

Rig #1 – currently does not have this timer installed – Cost $ 500 K

Rig #2 – will require modification to the timer on each stack: Cost :$ 500K

Expanded subsea testing of the Deadman/ Autoshear, beyond current practices and what is defined in API 53, could increase risk of harm to personnel, negatively impact the environment and cause unrecoverable damage to the rig or well.