July 16, 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–AA11*

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

To whom it may concern:

The American Petroleum Institute (API), the International Association of Drilling Contractors (IADC), the Independent Petroleum Association of America (IPAA), the National Ocean Industries Association (NOIA), the Offshore Operators Committee (OOC), the Petroleum Equipment & Services Association (PESA), and the US Oil and Gas Association respectfully submit the following comments on the proposed regulatory changes to Blowout Prevention Systems and Well Control requirements in 30 C.F.R. part 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 in the Outer Continental Shelf—Blowout Preventer Systems and Well Control.''

These trade associations represent oil and natural gas producers who conduct the vast majority of the Outer Continental Shelf (OCS) oil and natural gas exploration and production activities in the United States. Additionally, many of our associations' members are involved in drilling, equipment manufacturing, construction, and support services for the offshore oil and natural gas industry and all will be adversely impacted by this BSEE rulemaking.

Our members recognize that offshore operations must be conducted safely and in a manner that protects the environment. The U.S. offshore industry has advanced the energy security of our nation, and contributed significantly to our nation's economy. Our goal is for operations integrity and fit-for-risk designs, and we are concerned that many of the requirements in the proposed rule would increase environmental and safety risk in drilling operations rather than improve safety. In addition, we are concerned that the proposed rule would materially impair the ability to maintain current production operations, reduce future development and production or result in taking of leases and stranding of valuable reserves. To avoid these negative unintended consequences it is imperative that BSEE and industry collaborate to develop rules that are more workable and effective.

Our comments are submitted without prejudice to any of our member companies' right to have or express different or opposing views. We have encouraged all of our members to submit comments on the proposal.

In developing this response, industry drew on the expertise of eight workgroups comprised of over 300 subject matter experts from more than 70 companies and tens of thousands of man hours. Industry is providing this technically-based set of comments to aid BSEE in its efforts to create a robust and effective well control rule. As stated in our earlier comment letters, we believe additional time to review and comment on this lengthy and complex rulemaking was needed and, had it been provided, would have further contributed to the proposal's development. Indeed, additional time to review and comment on this complicated and lengthy rulemaking is warranted and needed to provide the public an adequate opportunity to participate as required under the Administrative Procedure Act. Going forward substantial industry-regulator engagement is imperative to generate and implement a workable and effective set of rules.

This letter highlights some of the proposed requirements that will have the greatest impact on industry, but there are numerous other specific proposed requirements that will also have significant impacts. Attachment A includes detailed information on how we believe these proposed regulations will significantly impact industry.

General Comments and Themes

Offshore drilling safety depends upon effective risk management. Since the release of the *Deepwater Horizon Investigation*, both the government and industry have implemented broad and extensive measures to improve the safety of offshore drilling operations and enhance worker safety and environmental protection. These measures represent far reaching improvements in standards, regulations and operations addressing safety and environmental management systems, offshore equipment, well design, and well control equipment targeted at prevention and containment and have established new procedures and tools for responding to oil spills.

The current proposed rule does not take these improvements into account and instead establishes prescriptive new requirements that would impose unjustified economic burdens discouraging economic growth, innovation, competitiveness and job creation contrary to Executive Order 13563. In many cases, these requirements are either impracticable or are ill-advised and in some cases would introduce new risk rather than reduce risk. In addition, the proposed rules create a number of undesired side effects which have not been accounted for in the Regulatory Impact Analysis. It is critical that all potential impacts are understood before such significant changes are introduced. Similar to the Initial Regulatory Impact Analysis (RIA) produced by BSEE on the Drilling Safety Rule and the Safety and Environmental Management System (SEMS) rules, the *Initial Regulatory Impact Analysis RIN: 1014-AA11*, published April 03, 2015, significantly underestimates impacts and overstates benefits. The justification provided in the preamble is neither clear nor understood by us.

The proposed rule is significant in both the scope of its requirements, as well as its overall impact. It imposes significant new requirements beyond global industry standards related to well design, well control, casing, cementing, real-time well monitoring, and subsea containment. In addition, the rulemaking not only incorporates guidance from several Notices to Lessees and Operators (NTLs) and industry standards, but also significantly revises provisions related to drilling, workover, completion, and decommissioning operations. The proposed rule impacts and unjustifiably impairs existing facilities and operations as well as facilities currently under development or construction and future operations.

Industry believes that many provisions of the proposed rule also lack articulated rationale. For instance, the discussion on proposed safe drilling margins states that BSEE wants to better define these margins. However, the proposed rule does not discuss how the current requirements are insufficient, how the new requirements were determined, or how these requirements would improve offshore drilling safety. The preamble refers to a recommendation from the *Deepwater Horizon Investigation*, but does not identify the specific recommendation nor explain its relevance to the proposed requirements. In effect, BSEE proposes mitigation, with no supporting rationale, for something that has not been identified as a problem. Not only does this make the proposed rule arbitrary, it also gives industry limited ability to develop or propose alternative strategies or technologies.

A consistent theme noted in the proposed regulation is for BSEE to take an increased role in day-to-day operations and critical decision-making processes. All decisions related to active offshore operations involve accepting a certain level of risk, responsibility and accountability. In the event BSEE seeks to increase its direct or indirect involvement in active drilling operations, further clarification is required on the associated responsibility, accountability and liability that BSEE would assume if an incident occurs as a direct result of those actions.

We request that BSEE arrange workshops with each of the eight industry workgroups that have analyzed respective sections of the proposed rule in order to reach mutual understanding of the proposal, to correct fundamental flaws in the proposed rule, and allow constructive development of rules that are ultimately both workable and effective. We further request that the comment period be reopened during the workshops and that the presentations and discussion be part of the official record.

Well Design (Safe Drilling Margin)
The proposed arbitrary changes to the safe drilling margin and lost circulation requirements will have significant practical and economic consequences in the design and construction of both shelf and deepwater wells. To evaluate the potential effect of the proposed safe drilling margin requirements, industry assessed the impact using a sample of 175 OCS wells drilled since June 2010. It is important to note that all 175 wells were completed under the existing regulations in a safe manner without significant well control incidents. Under the proposed regulations, 63% of the sample wells could not have been drilled as originally designed, as these wells required drilling margins less than the proposed one-half pound per gallon drilling margin or had lost returns.

The current risk-based approach to managing drilling margin (in combination with existing regulatory oversight) has been demonstrated to safely and economically drill wells having narrower drilling margins than the margins that would be allowed by the proposed rule. Production from the resulting wells benefits all stakeholders by providing royalty payments to the U.S. Treasury, supporting U.S. commerce, and reducing reliance on foreign oil imports.

The unintended consequences of the proposed rule will include significant economic and operational hurdles due to increased casing requirements, and smaller production casing sizes resulting in reduced rates or non-commercial production. Evaluation capabilities may also be impacted due to smaller hole sizes. Some new prospects and infill drilling programs will become un-drillable with infeasible prescriptive drilling margin requirements, while others will become cost and resource challenged and, as a result, potentially uneconomic. An offshore lease, however, provides operators valuable contractual and property interests in a purchased lease, *see, e.g.*, *Mobil Oil Exp. & Producing Se., Inc. v. United States*, 530 U.S. 604, 607–08 (2000); *Union Oil Co. of Cal. v. Morton*, 512 F.2d 743, 747 (9th Cir. 1975), and the Government materially breaches a lease when it substantially impairs the value of a lease by imposing new procedures that were not bargained for under the lease and prevent a lessee from exploiting its lease, *see Amber Res. Co. v. United States*, 68 Fed. Cl. 535 (2005); *Amber Res. Co. v. United States*, 73 Fed. Cl. 738 (2006), *aff'd* 538 F.3d 1358 (Fed. Cir. 2008). Further, an arbitrary, prescriptive safe drilling margin based only on mud weight and leak off test criteria may actually reduce the safety of drilling operations as the operator may not be able to choose the mud density best suited for the interval based on drilling and geological parameters. A lower mud weight may have to be used to meet the proposed requirement. The resulting reduction of the mud weight overbalance to the formation could create wellbore stability problems or potentially allow undesired influx of formation fluid into the wellbore. This adds unnecessary downhole drilling risk to the well construction process, possibly impacting personnel, environment and facilities.

Many Exploration Plans (EPs) and Development Operations Coordination Documents (DOCDs), especially in deepwater, include wells that will require drilling through depleted zones or other narrow margin conditions that are allowed under current regulatory protocols. The inability to drill these wells as a result of the prescriptive arbitrary drilling margin set in the proposed rule has the potential to harm project economics and reduce drilling and production on what could be multi-billion dollar developments. For projects on the cusp of approval, delays and cancellations should be expected. Given that hundreds of wells have been successfully and safely drilled with drilling margins smaller than would be allowable under the proposed rule, it is not clear what problem the rule is trying to solve.

The impact of the proposed rule on continued development and deployment of technologies such as managed pressure drilling technology, dual gradient drilling technology and riser pump systems would be detrimental. These technologies are deployed in narrow drilling margin environments to allow operators to effectively manage these drilling conditions. Such technologies and practices are already common place around the world and can improve drilling safety margins. Overly prescriptive regulations that do not allow for the use of these technologies provide a disincentive to develop them. If these regulations are imposed in the U.S., they will create a competitive disadvantage to OCS lease holders as compared to the rest of the world.

Through well-established operational procedures, hundreds of wells with margins smaller than that required in the proposed rule have been drilled successfully and safely. API Bulletin 92L *Drilling Ahead Safely with Lost Circulation in the Gulf of Mexico* (API 92L) summarizes best drilling practices when drilling wells with narrow drilling margins. API 92L addresses BSEE's concern to document and codify safe drilling margin practices and reduces the need for more prescriptive drilling margin requirements. Therefore, this document should be incorporated by reference into the final rule, in lieu of more stringent drilling margin regulations, for operations where equivalent site-specific lost returns procedures have not been developed.

In summary, a large proportion of the wells drilled in OCS waters will be directly impacted by the proposed drilling margin requirements. Many of the deep wells or wells with depleted zones drilled in OCS waters do not have additional casing options which will negatively affect well completions or, as described above, render wells un-drillable. In addition, new technologies being developed may no longer be available, rendering OCS lease holders uncompetitive. Industry, with input from BSEE, developed API 92L as a guide to safely address lost circulation and low drilling margins. It is an alternative to more prescriptive regulations.

BOP Equipment

There are several important items with respect to BOP equipment. Most notably is the overly prescriptive language on certain requirements, such as: accumulator sizing; testing; BOP configurations; providing access to facilities; Quality Assurance/Quality Control (QA/QC); and oversight imposed on the lessee.

Infeasible 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 application for permit to drill (APD) or application for permit to modify (APM) or a regulatory deadline. There is no guarantee that such services will be available. Even if available, the proposed implementation dates do not allow for a reasonable period of time between the initial approval of a BAVO and the effective date of the provisions of the rule requiring the use of the BAVOs' services. If BAVO provisions are retained in the proposed rule, then there needs to be a reasonable implementation schedule to not interrupt current and planned drilling and production operations.

Except as specified otherwise, BSEE has proposed an effective date of three 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 complied with until the BAVO has been approved. Therefore, in order to provide the certification required by proposed § 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. This has the potential to place an effective moratorium on OCS drilling.
- Most existing surface stacks are not equipped with hydraulically operated locking devices. Compliance with the proposed § 250.735(g) would require time to complete the up-front engineering services (including design and qualification testing) and upgrade of the stacks and control systems prior to the date where such stacks must be identified in an APD or APM.
- Given the other demands the proposed rule will place on equipment manufacturers, industry considers three years as a minimum more feasible timeline for implementation of this requirement.

Imposition of requirements beyond those addressed in API 53

The proposed requirements that exceed the provisions of API Standard 53 (API 53), *Blowout Prevention Equipment Systems for Drilling Wells* are unnecessary and will not improve safety. Specifically, the requirements are problematic as follows:

- Implementation of the rule as proposed would require many more accumulators to satisfy larger volumetric requirements leading to larger and heavier BOP stacks than are presently in use. Heavier stacks will result in unintended negative consequences related to their handling, deployment and operation which will impact well construction and design and impose limitations to re-entry into existing wells.
- Many mobile offshore drilling units (MODUs) do not have available space to install the prescribed additional surface BOP accumulator bottles that would be required. In all cases, the additional required associated equipment (e.g., larger fluid reservoir, additional pumps, additional accumulator bottles, etc.) would be problematic in their demands for space and contribution to additional complexity of rig systems. The need for such equipment has not been justified.
- Unnecessarily large accumulator capacities may not be practical and could necessitate removal of other BOP well control components, thereby reducing redundancy and well control options for many vessels.
- 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. Every time the device must be operated for testing, this increases the risk of limiting the vessel's capability to actually disconnect, on some systems, in order to meet the proposed requirement both pods are powered down and at that point the vessel is exposed to drift/drive off damage. It is important to inspect, maintain and verify operation and this should be done at intervals designed to best manage risk, as defined in API 53.

Restrictive language on the configuration for the installation of blind-shear rams could lead to loss of additional pipe rams in order to accommodate the prescriptive requirements of the proposed rule. A risk assessment should be conducted and is the correct tool to determine the placement of all rams.

The requirement in the proposed rule for the lessee to ensure that BSEE has access to any facility and to provide prior notification of any shear testing is not feasible absent a significant revision to the placement of regulatory responsibility within 30 CFR Part 250. As presently written, "You" as defined in the rule applies to the lessee. The lessee is not always aware of research and development activities being performed by individual companies or manufacturers.

Similarly, requirements within the proposed rule relating to QA/QC oversight by the lessee are infeasible because the vast majority of designs, manufacturing and testing are completed before a contract is concluded between the purchaser of the equipment (e.g., a drilling or well servicing contractor) and the lessee.

Real Time Monitoring (RTM)

Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. Their objective is to determine what measures could reduce the safety and environmental risks of offshore oil and natural gas operations and to make a recommendation on whether RTM should be incorporated into BSEE's regulatory scheme. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.

The proposed rule may be interpreted to suggest that BSEE wishes to shift operational decision-making away from rig site personnel to shore. Shifting decision-making away from the offshore personnel should not be the intent of the RTM provisions in the rule as this exposes the operations to increased risk levels. In times where situational awareness is extremely important and immediate action is required, if not integrated into the operations, Remote RTM can become a distraction or, in extreme cases, create an environment of complacency or confusion over accountability. During any given operation, the personnel on the rig offshore 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 operators' governing procedures and operations integrity guidelines. This authority includes full control of the operations and the full authority to stop activities at any time.

Generally, operators that use shore-based operations centers do so to assist personnel on the rig with the monitoring of specific functions of the drilling operation, not to assume control of operational activities. Operators must retain the flexibility to develop a performance-based approach (rather than follow a prescriptive requirement) described in a Real Time Monitoring Plan similar to the safety and environmental management system (SEMS) program under 30 CFR 250.1900 or the training plan under 30 CFR 250.1500. The Real Time Monitoring Plan should describe what functions of these systems will be monitored in the well(s), which will vary with the rig and its equipment, as well as the location of any support facilities onshore.

Industry would develop a guide to describe the content of a Monitoring Plan. The Monitoring Plan would describe the qualifications of the personnel at the onshore monitoring location and the established protocols that would define when and to whom internal notifications are made when communications outages occur. It should be clear to BSEE that it remains the primary responsibility of the rig-based 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.

Inappropriate use of real-time data centers may lead to an erosion of responsibility and accountability of offshore personnel 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 can be no guarantee of sufficient time to interact with shore base support centers to plan a response. It is during such critical moments that offshore supervision is key, and its effectiveness can only be maintained if the primary decision-making remains focused at offshore locations where situational awareness is crucial. To ensure offshore personnel are equipped with the necessary knowledge prior to specific operations, industry practice is for a range of preparatory engagements to be held with the shore base engineering and operations support teams or through on-site engineering 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.

Prior to any rulemaking requiring RTM, serious consideration is required to address cybersecurity concerns when accessing data from operational safety systems (e.g., station keeping, BOP health and status). Opening of data streams to the operational safety systems poses the risk of introduction of viruses or malware. Access from a remote location to any systems on a rig should be fully understood and risk assessed prior to imposition of a regulatory mandate for providing such remote access. Challenges for RTM also include the need for new data transmission protocols and for their adoption throughout industry. This would be a significant change from the current Well Information Transfer Specification (WITS) protocols.

Casing and Cementing

A number of the casing and cementing requirements outlined in the proposed rule are unclear and require design changes that are either not feasible or reduce the chance of safe and successful execution.

For example, proposed § 250.420(c)(2) seeks to increase use of weighted fluids during cementing, without consideration of a number of complications. Increasing mud weight during cement operations increases the risk of lost circulation and may result in failing to attain the required top of cement. Although the higher applied pressure increases the critical gel strength, this pressure is not transmitted through the cement slurry during the slurry's Critical Gel Strength Period. Therefore, additional pressure may be insufficient in the absence of a cement slurry design that properly addresses the Critical Gel Strength Period. The proposed rule may also prohibit the judicious use of un-weighted pre-flushes as a tool for reducing equivalent circulating density (ECD) as a means of improving the chance of a successful cement job.

Overall, these complications can be avoided by maintaining the current regulations that reference API Standard 65-2, 2nd Edition. This standard describes method(s) of isolating potential flow zones. Further detailed remarks on the proposed casing and cementing requirements are included in Attachment A, E, F and G.

Incorporation of API Standards by Reference

Since 1924, API has been the leader in developing industry standards that promote reliability and safety through the use of proven engineering practices. Reviewing and improving industry standards has always been a top priority and practice of the Institute. Since 2010, API has published over 100 new or revised exploration and production standards, covering everything from deepwater well design, to casing and cementing, to capping stacks, to blowout preventers.

API appreciates the fact that a number of its standards are proposed for incorporation by reference in the proposed rule. However, there are instances where this does not appropriately reference the standard's edition or is otherwise unclear or out of context. We offer the following comments:

- 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 refer to the Second Edition, September 2013.

- Industry fully supports the incorporation of API Standard 53 (API 53), *Blowout Prevention Equipment Systems for Drilling Wells*, Fourth Edition, November 2012 in its entirety. Through the incorporation by reference of API 53, its normative references (e.g., API Specifications 16A, 16C, 16D and API Recommended Practice 17H) also apply (in part or whole) in context, as specified within the Standard.

- If BSEE intended to reference API Specifications 16A, 16C, 16D and API Recommended Practice 17H for purposes other than their relation to API 53, then those purposes should be specifically stated within the rule or removed entirely. If included, the incorporation by reference of ANSI/API Spec. 16A, *Specification for Drill-through Equipment*, ANSI/API Spec. 16C, *Specification for Choke and Kill Systems*, API Spec. 16D, *Specification for Control Systems for Drilling Well control Equipment and Control Systems for Diverter Equipment* and API Recommended Practice 17H – *Remotely Operated Tools and Interfaces on Subsea production Systems* should be revised such that each edition is cited in a manner such that it is applicable to equipment manufactured after the publication date of the standard to prevent existing equipment and facilities that were manufactured and accepted under previous standards from being rendered obsolete. Any additional requirements against a particular edition need to be justified.

- 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. Effective Date: June 1, 2014. This 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.

- The incorporation of ANSI/API Specification 6A/ISO 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.

- The incorporation of ANSI/API Specification 11D1/ISO 14310:2008 (Modified) *Packers and Bridge Plugs*, should be updated to the Third Edition, April 2015. Incorporating the current edition of API 11D1 ensures alignment of supplier/manufacturer documentation with the rule.

Containment

Cap and Flow

The proposed requirements related to containment appear to assume that a cap and flow system, in addition to a cap and contain system is required to control a source at the seafloor in the event of a blowout. If the operator's evaluation using the BSEE-endorsed well containment screening tool indicates that a wellbore can sustain a full shut-in without allowing reservoir fluids to broach the seafloor, then cap and flow well design and equipment should not be required in the operator's permit. Cap and flow well design and equipment should be required for permit approval if the wellbore integrity analysis indicates loss of wellbore integrity while performing a full shut-in during an uncontrolled well event.

Shallow Water Containment

In the preamble of the proposed rule, BSEE solicited comments on whether the source control and containment requirements should be applicable to wells drilled in shallow water. Current subsea containment requirements only address deepwater GOM drilling operations using a subsea BOP or surface BOP on a floating facility. The presently required equipment for a 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 area. Any additional requirements for fixed-bottom drilling operations should be addressed through a separate rulemaking process that takes into account the unique risks and work environment in shallow water that utilizes different resources compared to deepwater operations.

The regulation should be less prescriptive, allowing for potential improvements in technology and equipment, thereby improving response.

The Offshore Operators Committee has formed a Shallow Water Source Control Workgroup committed to considering value of shallow water containment guidelines for GOM shallow water operations, any rulemaking on shallow water containment should be deferred until the OOC work is complete.

Seabed Source Control Alternatives

Although 30 CFR § 250.141 provides for the use of alternative procedures and equipment, it is unclear how these would be approved. We recommend the requirements be made less prescriptive and open to providing functionally equivalent means for source control to allow for technological advancements. The proposed 30 CFR § 250.141 fails to address the issue as there is no explanation of the perceived risk reduction benefit of the enhanced requirement, which is critical to establishing the baseline expectation. Furthermore, the proposed rule fails to establish justification for the enhanced requirement as required by Executive Order 13563.

Free Standing Hybrid Riser (FSHR)
In lieu of prescriptive FSHR monitoring requirements in the proposed regulations, monitoring requirements should be addressed in an operator's Deepwater Operations Plan (DWOP) as approved by BSEE. The DWOP has proven to be a comprehensive and systematic means of managing deepwater production risks.

Inspection and Mechanical Integrity
The proposed rule includes a number of inspection and mechanical integrity requirements that go beyond industry best practices and would not improve safety. Examples include: requiring periodic inspection of BOP equipment to be completed at a single point in time; personnel maintaining BOP equipment to meet OEM training recommendations that do not exist; and specifying testing requirements under extreme and unlikely conditions (which were not, in many cases, part of the design scope). In some cases the proposed requirements reduce safety and could cause harm to the environment. Currently, industry successfully utilizes inspection, certification, and verification processes that balance the availability of existing infrastructure while managing safety and reducing risk. Through the application of robust operational management processes, industry effectively manages risk and delivers beneficial results. Through a staged approach to equipment certification, the processes for inspection and mechanical integrity in use today allow operators to maintain ongoing safe operations and reliable equipment that meets or exceeds the needs of industry.

The process used today, which has proven to be safe and effective, is preferable to the certification approach in the proposed rule, which will require the BOP and (not clearly defined) "every associated system and component" to undergo additional certifications that must be completed by the same inspectors and certifying entities by a common due date. This proposed certification approach will lead to rigs being out of service for extended periods and strain existing certification infrastructure that has been established to support staged inspections. The proposed scheme could result in unintended consequences, such as the degradation of perfectly good, tested, equipment during what would become an expedited project period, while neither reducing risk nor improving safety. Further, expansion of the inspection process dilutes resources and focus, which may also result in increased risk.

BSEE has complete control of the permitting process and the obligation to withdraw an existing permit or deny a new permit if an operator does not have effective systems 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 BSEE's Safety and Environmental Management System (SEMS) rule.

Industry respectfully requests that proposed expansion of the certification process be removed from the rule to avoid negative consequences.

Certification by BSEE-approved verification organizations (BAVOs)
Industry does not see the need for BSEE to approve third party organizations as BAVOs.

If proposed requirements for BAVOs are retained:

- Requirements for certifications by a BAVO should not go into effect until at least 12 months after the initial BAVO list is published.
- If BSEE is to restrict industry's choice of third parties by requiring use of BAVOs, BSEE must establish criteria for verification organizations to ensure they are qualified and adequately staffed with competent personnel to fulfil the role of a verification organization.
- BSEE must also develop and implement a process for providing interpretation of its regulations, and any standards incorporated by reference, to the BAVOs. This process must be made entirely transparent.
- Industry must be provided with a means of recourse to BSEE on decisions made by BAVOs where there is a difference of opinion regarding application or interpretation of a rule or standard.
- BSEE must develop and implement a process to periodically assess and verify that the verification organizations continue to meet BSEE's criteria.
- BSEE should clarify for industry what accountability BSEE is assuming in selecting the verification organizations, and BSEE's expectations on long term management of the verification given that rigs often leave to fulfil contracts overseas and return to areas subject to BSEE jurisdiction.

Overall, the use of BAVOs does not meet the objective to manage and reduce risk to the lowest level practicable. Rather than requiring an additional verification organization, which has a limited understanding of the ultimate service provided, the rule should direct industry to perform risk assessments to determine the optimum equipment inspection requirements and required preventative and mitigating actions for any particular drilling operation.

Economic Analysis
The RIA is flawed and, consistently and substantially underestimates the absolute cost impacts the proposed rule would have. The RIA estimated undiscounted 10-year incremental costs of the rule over baseline totals at approximately $883 million. An independent cost and economic assessment performed by Blade Energy Partners (Blade) and Quest Offshore (Quest) estimated cumulative 10-year costs at approximately $32 billion. A copy of the Quest/Blade study is attached (Attachment B) and included for the administrative record.

In addition, the RIA fails to account for and acknowledge the broader economic impacts of the proposed rule on industry and the nation from the immediate and long-term reduction of U.S. offshore oil and natural gas development and production. The proposed rule will likely have significant impacts on offshore oil and natural gas investment, oil and natural gas production, supported employment, U.S. Gross Domestic Product and government revenues. The Quest/Blade analysis projects that the proposed rule relative to baseline would: reduce cumulative capital investments and other spending by more than 10%; reduce 2030 Gulf of Mexico oil and natural gas production from 3.1 million barrels of oil equivalent to 2.6 million barrels of oil equivalent, a reduction of approximately 15%; reduce total employment supported by Gulf of Mexico offshore development by over 50,000 jobs, as early as 2027; reduce the 10-year cumulative supported U.S. Gross Domestic Product from 2017 to 2026 by $27 billion; and reduce total collected 10-year government revenues by $9.9 billion.

The 10-year assessment period is insufficient to fully assess the impact of this proposed rule on OCS operations. Because the rule would apply to development projects and major capital equipment that typically have lifespans of 20-30 years and beyond, it is critical for the BSEE assessment to consider the associated later life impacts.

The associated economic impacts of the proposed drilling margin requirements have not been addressed by BSEE and should be evaluated in order to review the full range of impacts. As described previously, the revised drilling margin requirements will prevent a large number of wells from being drilled or require the addition of casing strings to meet the arbitrary requirements. The Quest/Blade analysis projects that this could reduce the average number of wells drilled per year in the Gulf of Mexico by 26%, significantly impacting total investment in the region. Most of the estimated economic impacts described above are due to new drilling margin requirements. For the subset of wells that could continue with the addition of extra casing strings, the RIA should consider the additional time, risks and actual cost impacts associated with the incremental operations. Similar considerations should be applied for wells impacted by the revised packer fluid requirements that will result in similar well feasibility and redesign issues.

Many of the proposed BOP requirements will require significant time to implement and can only be completed when the rig is out of service, potentially in the field or in a shipyard. The Quest/Blade evaluation of the proposed rule estimates the total 10-year BOP related costs at over $12 billion. The estimates provided by BSEE in the RIA do not consider these impacts and as a result the impact is drastically underestimated. For example, the increased subsea accumulator requirements may require capital investment for extra bottles that must either be retrofitted to existing BOP frames, complicating and increasing time taken for routine maintenance, or installed subsea as standalone systems that must be deployed on every well and maintained separately. All the impacts noted in Attachment A must be considered in the RIA, to ensure an adequate assessment has been made of all of the proposed changes and that the changes are considered against any potential benefits.

Implementation of the rule has the potential to disrupt normal contracting practices. The numerous provisions of the rule that impose requirements beyond those reflected in API 53 are unlikely to be accepted in the international marketplace, which will likely limit the number of MODUs readily qualified to be contracted for operation in areas under BSEE jurisdiction. As a result, the supply of readily available drilling units would likely be reduced, resulting in increased demand for qualified MODUs and spread rates for lessees, and reduced U.S. drilling and development. These costs and the broader domestic supply and economic impact have not been addressed in the proposed economic analysis.

The timing of contracts may also be affected, as operators would understandably prefer not to contract for the services of a rig that 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)(1)), or during periods when significant compliance costs or operational uncertainties may be incurred (e.g., as with the proposed § 250.739(b)).

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, and has not been considered in the economic analysis.

The effect of implementing the proposed rule would be particularly acute for self-elevating MODUs (jack-ups) where the equipment is older and the market for their services in the U.S. is already fragile. Very few jack-ups in the U.S. are under term contracts, and the well-to-well nature of these contracts makes it easy for many rigs to be released quickly. Rigzone Data Services reported that in early November 2014, there were 34 marketed jack-ups, 14 more than on June 2, 2015. Of the marketed jack-ups, 21 were then under contract, more than double the number (10) under contract on June 2, 2015. Rigzone also reported the leading edge day rate for a 300-ft, independent-leg cantilever jack-up was $130,000 in November 2014 versus $85,000 in June 2015. Further economic assessment by BSEE is required to understand and acknowledge the impact that further degradation of this market will have on businesses which rely on such activity.

Although a broad range of costs has been considered in the RIA, there are a number of potential cost impacts that have been overlooked. An underlying assumption made in the analysis is that the current operating accepted practice is equivalent to the "no action" (OMB Circular A4) baseline (for example SCCE provided by MWCC and HWCG). However, unless the accepted practice is already a minimum regulatory requirement, it should be included as an incremental cost. 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 omission reflects an intended "grandfather" scheme, then regulatory text to provide for the exclusion of existing equipment should be included in the proposed rule.

Finally, consideration should be given to the global energy security implications of a U.S. regulatory activity that could adversely impact U.S. energy production and domestic investment. The U.S. has risen to a position of global energy superpower, and U.S. production has significantly altered the global energy paradigm by adding significant supplies of crude oil to the global marketplace. These added supplies have helped to provide stability to the global marketplace, particularly for our allies who are increasingly looking to the U.S. as a stable oil and natural gas supplier. Here at home, we have the opportunity to embrace the role of energy superpower by encouraging continued investment in critical energy projects, especially in the capital intensive offshore market. BSEE should therefore ensure that any new regulatory requirements are not only safe, feasible, cost-effective, and enforceable, but that they do not unnecessarily erode the strong national security gains that have been achieved through domestic oil and gas production.

Probabilistic Risk Assessments (PRA)
The preamble requests comments related to the practice of utilizing PRA modelling in those operations incorporated within the proposed rule. While PRA may be a useful approach in certain circumstances, it will be of limited value for the oil/natural gas/drilling industry for several reasons. First, there are limited data/inputs (e.g., lack of failure rate data) to develop a meaningful PRA that will provide useful results and a lack of established criteria/benchmarks. There is also a risk of study quality (i.e., lack of standardization) that will lead to variability in results.

The use of PRA methodology will NOT help BSEE in its final decision on this proposed regulation because it will take years to collect the needed data, generate the probabilistic curves, run the analysis, and determine a PRA methodology that generates consistent results via a BSEE model. Nevertheless, BSEE should investigate PRA methodology as well as other Probabilistic Techniques to determine effective techniques that would help BSEE in its future decision making. This review should be done in a collaborative effort with industry, given that industry data will be required.

We strongly suggest that any recommendation on future studies or methods be coordinated with an experienced multidisciplinary team involving process safety engineering experts, drilling and completion experts, well operation experts, and other disciplines relevant for the task. The initial focus should be on developing studies that can focus on the already known challenges and common failure modes (i.e., strength of existing barriers, common failure modes, cultural change, test and verification of equipment considered critical such as gas detectors in the fluids returning from the well, instrumentation for early detection of gas in the riser, etc.).

Applicability to Existing Facilities and Equipment
It is not clear whether existing facilities will be "grandfathered in," or whether they will have to comply with the new requirements of the rule, a very expensive requirement. Similarly, it is not clear whether equipment already under construction will have to comply with the new requirements if they are finalized or become effective prior to the startup of new facilities; such compliance may not be possible without a significant delay and associated costs. BSEE needs to provide industry with clarity regarding the application of the proposed rule to existing facilities and equipment and consider varied implementation timeframes to meet reasonable expectations. If certain facilities and equipment are not "grandfathered in," the significant economic impacts must be considered as part of the RIA.

BSEE Solicitation of Information versus Proposed Regulatory Provisions
There are over ninety instances in the proposal for which BSEE is soliciting comments but it has not previously engaged industry on the topics or proposed any regulatory text. Our expectation is that BSEE would first engage industry directly in early discussions and then propose regulatory language to give the regulated community the required notice and meaningful opportunity to comment before adopting a final rule on these issues.

Conclusion
Safety is a core value for the oil and natural gas industry. We are committed to safe operations and support effective regulations in the area of blowout preventer systems and well control.

Industry appreciates the opportunity to comment on this very important rulemaking and is available for further discussions at your convenience. Please feel free to contact us with any questions.

Sincerely,

Holly Hopkins, API

Alan Spackman, IADC

Daniel Naatz, IPAA

Randall Luthi, NOIA

Evan Zimmerman, OOC

Leslie Beyer, PESA

Alby Modiano, US Oil and Gas Association

Attachments

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§ 250.107	(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and (4) Complying with all lease, plan, and permit terms and conditions. (e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.		Accept proposed text
§250.107(a)(3)	Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities.		Accept proposed text
§250.107(e)	The BSEE may issue orders to ensure compliance with this part, including but not limited to orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.		Accept proposed text
§250.198(h)(51)	(51) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, Errata June 2009; incorporated by reference at §§ 250.292, 250.733, 250.800, 250.901, and 250.1002	Should reference the 2nd edition of 2RD, September 2013	(51) API 2RD, Dynamic Risers for Floating Production Systems, Second Edition, September 2013; incorporated by reference at §§250.292, 250.733, 250.800; 250.901 and 250.1002;
§250.198(h)(63)	(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012; incorporated by reference at §§ 250.730, 250.737, and 250.739;	Reference API 53 in its entirety. API 53's normative references should be referenced in the rule as the edition that is in effect at the date of manufacture.	Reference API 53 in its entirety with regards to 16A, 16C, and 16D such that only the relevant provisions of those references apply. The editions of API 16A, 16C, and 16D should be those that were in effect at the date of manufacture of the specific equipment.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.198(h)(68)	(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008; incorporated by reference at §§ 250.730 and 250.806	The ninth 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.	(68) 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
§250.198(h)(70)	(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; incorporated by reference at §§ 250.730, 250.806, and 250.1002	The incorporation of API Specification 6A, 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. ISO 10423 has been reissued, Fourth Edition, 2009-12-15. It should be noted that given that SPPE is required to be "manufactured and marked pursuant to API Spec. Q1" per Section 250.801 (b), then only 6A is applicable as only 6A includes the API monogram program i.e. ISO 10423:2003 is not identical in this regard. API Specification 6A718 First Edition, March 2004 should also be referenced for completeness.	§250.198(h) (70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Specification for Wellhead and Christmas Tree Equipment (includes Errata 1 dated January 2011, Addendum 1 and Errata 2 dated November 2011, Addendum 2 dated November 2012, Addendum 3 dated March 2013, Errata 4 dated August 2013, Errata 5 dated November 2013, Errata 6 dated March 2014, and Errata 7 dated December 2014); incorporated by reference at §§ 250.730, 250.806, and 250.1002.
§250.198(h)(89)	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Identical), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Second Edition, Effective Date: January 1, 2010; incorporated by reference at §§ 250.518, 250.619, and 250.1703	Incorporate the Third Edition by reference. Incorporating the current edition of 11D1 ensures alignment of supplier/manufacturer documentation with the federal rule.	(89) ANSI/API Spec. 11D1, Packers and Bridge Plugs, ISO 14310:2008 (Modified), Petroleum and natural gas industries—Downhole equipment—Packers and bridge plugs, Third Edition ; incorporated by reference at §§ 250.518, 250.619, and 250.1703
§250.198(h)(90)	(90) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004; incorporated by reference at § 250.730		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(91)	(91) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993; incorporated by reference at § 250.730		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(92)	(92) API Spec. 16D, Specification for Control Systems for Drilling Well-control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004; incorporated by reference at § 250.730;		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.198(h)(93)	(93) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011; ISO 13628-4 (Identical), Design and operation of subsea production systems-Part 4: Subsea wellhead and tree equipment; incorporated by reference at § 250.730; and		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.198(h)(94)	(94) ANSI/API RP 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, ISO 13628-8:2002 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems, First Edition, July 2004, Reaffirmed: January 2009; incorporated by reference at § 250.734		In accordance with API Standard 53, as incorporated by reference § 250.198;
§250.199(E)(15)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.)** (15) Subpart O, Well-control and Production Safety Training (1014–0008). **BSEE collects this information and uses it to:** (i) Evaluate training program curricula for OCS workers, course schedules, and attendance. (ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.		Accept proposed text
§250.199(E)(16)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.) (16) Subpart P, Sulphur Operations (1014–0006). BSEE collects this information and uses it to: (i) Evaluate sulphur exploration and development operations on the OCS.** **(ii) Ensure that OCS sulphur operations meet statutory and regulatory requirements and will result in diligent development and production of sulphur leases.**		Accept proposed text
§250.199(E)(17)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.) (17) Subpart Q, Decommissioning Activities (1014–0010). BSEE collects this information and uses it to: Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.**		Accept proposed text
§250.199(E)(18)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.)** (18) Subpart S, Safety and Environmental Management Systems (1014–0017), including Form BSEE–0131, Performance Measures Data. **BSEE collects this information and uses it to:** (i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel). (ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.199(E)(19)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.) (19) Application for Permit to Drill (APD, Revised APD), Form BSEE-0123; and Supplemental APD Information Sheet, Form BSEE-0123S, and all supporting documentation (1014-0025). BSEE collects this information and uses it to: (i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling.** **(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.**		Accept proposed text
§250.199(E)(20)	**30 CFR subpart, title and/or BSEE Form (OMB Control No.)** (20) Application for Permit to Modify (APM), Form BSEE-0124, and supporting documentation (1014-0026). **BSEE collects this information and uses it to:** (i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment. (ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.292(p)	If you propose to use a pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by § 250.292(f) and (g):by paragraphs (f) and (g) of this section: (1) A detailed description and drawings of the FSHR, buoy and the tether system; (2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths; (3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198); (4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can; (5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (e.g., corrosion) that may negatively impact the riser or tether; and (6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA	1) FSHR is most attractive solution for a floating production storage unit (FPSO) in the GOM, but it can also be used for other types of floater. . 2) The most critical parameter to maintain FSHR integrity is tension. Hence, a tension monitoring system is mandatory. Other parameters requiring monitor may not be realistic or achievable such as fatigue (currently there is no means to directly measure fatigue) and corrosion. Suggest removal of those parameters and instead stressing the use of tension monitoring.	If you propose to use a permanent pipeline free standing hybrid riser (FSHR) that utilizes a critical chain, wire rope, or synthetic tether to connect the top of the riser to a buoyancy air can, provide the following information in your DWOP in the discussions required by § 250.292(f) and (g): by paragraphs (f) and (g) of this section: (1) A detailed description and drawings of the FSHR, buoy and the tether system; (2) Detailed information on the design, fabrication, and installation of the FSHR, buoy and tether system, including pressure ratings, fatigue life, and yield strengths; (3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198); or current approved industry standard at the date of manufacture; (4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can; (5) Descriptions of your monitoring system and plan for monitoring the riser top tension variation for a permanent FSHR system; and (6) Documentation that the tether system and connection accessories for the pipeline FSHR verified by the CVA and manufactured by a class approved manufacturer.
§250.400	Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.411(a)	**Information that you must include with an APD:** (a) Plat that shows locations of the proposed well, **Where to find a description:** § 250.412.		Accept proposed text
§250.411(b)	**Information that you must include with an APD: (b) Design criteria used for the proposed well Where to find a description: § 250.413**		Accept proposed text
§250.411(c)	**Information that you must include with an APD: (c) Drilling prognosis, Where to find a description: § 250.414**		Accept proposed text
§250.411(d)	**Information that you must include with an APD: (d) Casing and cementing programs, Where to find a description: § 250.415.**		Accept proposed text
§250.411(e)	**Information that you must include with an APD:** (e) Diverter systems descriptions, **Where to find a description:** § 250.416.		Accept proposed text
§250.411(f)	**Information that you must include with an APD:** (f) BOP system descriptions, **Where to find a description:** § 250.731.		Accept proposed text
§250.411(g)	**Information that you must include with an APD:** (g) Requirements for using an MODU, **Where to find a description:** § 250.713.		Accept proposed text
§250.412(h)	**Information that you must include with an APD:** (h) Additional information, **Where to find a description:** § 250.418.		Accept proposed text
§250.412(h)	**Information that you must include with an APD:** (h) Additional information, **Where to find a description:** § 250.418.		Accept proposed text
§250.413(g)	(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;	This rule requires entry of ECD information into the APD pore pressure/fracture gradient plot. Clarification is needed as to how (depth, mud weight, pump rate) this ECD is expected to be calculated and used. Clear direction is needed to avoid incorrect assumptions, such as comparing actual field data with calculated data since these may be taken at different depths (measured ECD depth may be thousands of feet below the calculated ECD depth at a shoe). A prescriptive requirement that does not address where and how the calculation will be used can result in negative consequences.	(g)A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, equivalent circulating density at the shoe or identified weakest zone (using maximum interval mud weight and flow rate), and casing setting depths in true vertical measurements. This plot will be used for design purposes only. As an alternative, delete ECD reference if unable to specify intended use.
§250.414(c)	(c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:	Safe drilling margins apply only to "drilling wells" and should not be confused with other operations such as cementing or completions operations. Contrary to the suggestion in the preamble of the proposed rule, the Deepwater Horizon was performing non-drilling well abandonment operations at the time of the incident.	Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.414(c)(1)	(1) Static downhole mud weight must be greater than estimated pore pressure;	When using Synthetic Based Mud (SBM), there may be a significant difference between Surface Mud Weight (SMW) and Downhole Mud Weight (DHMW) due to compressibility and thermal effects. This delta must be accounted for on deep, complex wells on a case-by-case basis. However, many wells are drilled with Water Based Mud (WBM) or to shallow depths with SBM where the delta is inconsequential. Therefore, the requirement to use DHMW in this clause is overly prescriptive as it will add unnecessary complexity to all wells, thereby diluting the focus of engineering and operational personnel on more pressing process safety issues. An unintended consequence of being overly prescriptive for DHMW is that it may not allow the use of established technologies such as Managed Pressure Drilling. These technologies could require use of DHMW less than the pore pressure, with surface pressure being exerted on the mud column to maintain well control. See attachment C for a comprehensive explanation of the terms used in this comment.	(1) Bottom hole pressure (equivalent mud weight plus surface pressure as applicable) must be greater than estimated pore pressure.
§250.414(c)(2)	(2) Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	Industry acknowledges the safety concerns BSEE has regarding drilling margins and the need for increased vigilance. Avoidance of incidents is paramount, especially in difficult hole sections. Industry has consistently shown the ability to be able to drill without arbitrary prescriptive safety margins, through safe drilling practices. Due the complexity and unintended consequences of a prescriptive drilling margin, please refer to Attachment D for more detail on why a 0.5 ppg drilling margin should not be codified.	It is recommended to delete 250.414 (c) 2. If not deleted, should be changed to: The bottom hole pressure (equivalent mud weight plus surface pressure as applicable) must be below the lesser of the casing shoe integrity test or the lowest actual / estimated fracture gradient, with a risk assessed safety margin consistent with the expected well conditions and current well operations. This is conducted in accordance with API 92L.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.414(c)(3)	(3) The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient;	The industry understands the drilling safety concerns BSEE has with ECD, loss of mud and well control. Industry has successfully managed these processes for many years when drilling in the GOM and other OCS areas. The proposed rule could be interpreted (when combined with all of 250.414) to stop drilling when any lost circulation occurs. A review of 175 OCS wells drilled after June 2010 found that 46% experienced full or partial returns (as defined in API 92L). Utilizing solutions from API 92L, allows a prudent operator to mitigate their risk whereby they may safely drill ahead in a difficult hole section.	(3)The equivalent circulating density must be below the lesser of the casing shoe pressure integrity test or the lowest actual/estimated fracture gradient; if lost circulation occurs, then the losses should be mitigated, and/or ECD managed to reduce the effects of lost circulation as per API 92L.
§250.414(c)(4)	(4) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related hole behavior observations.	This section is for planning (prognosis) purposes and should not be applied to operations. Rigorous prognosis preparation is critical to ensure good execution. Refer to API 92L for more information.	(4) When determining the pore pressure and lowest estimated fracture gradient during planning for a specific interval, relevant offset hole behavior observations must be considered.
§250.414(h)	(h) A list and description of all requests for using alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;		Accept proposed text
§250.414(i)	(i) Projected plans for well testing (refer to § 250.460);		Accept proposed text
§250.414(j)	(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and		Accept proposed text
§250.414(k)	(k) Any additional information required by the District Manager.		Accept proposed text
§250.415(a)(1-4)	(a) The following well design information: (1) Hole sizes, (2) Bit depths (including measured and true vertical depth (TVD)), (3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval, and (4) Locations of any installed rupture disks (indicate if burst or collapse and rating);		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.416	You must include in the diverter descriptions: (a) A description of the diverter system and its operating procedures; (b) A schematic drawing of the diverter system (plan and elevation views) that shows: (1) The size of the annular BOP installed in the diverter housing; (2) Spool outlet internal diameter(s); (3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and (4) Valve type, size working pressure rating, and location.	All diverters do not use annular elements, some use insert elements which are not the same.	You must include in the diverter descriptions: (a) A description of the diverter system and its operating procedures; (b) A schematic drawing of the diverter system (plan and elevation views) that shows: (1) The size of the sealing element installed in the diverter housing; (2) Spool outlet internal diameter(s); (3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and (4) Valve type, size working pressure rating, and location
§250.418(g)	A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below mudline you propose to displace cement and how you will visually monitor returns;		Accept proposed text
§250.420	You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of Subpart G.	Responses to be found in the individual subparts. This is a high priority response.	
§250.420(a)(6)	(6) Provide adequate centralization to ensure proper cementation; and	The current wording of the requirement needs to be changed to include methods other than centralizers to meet the cementing requirements of the hole section. The language appeared to drive a requirement to place centralizers on all casing strings. There are instances where doing this will actually increase risk. Some of the associated risks include but are not limited to: 1. inability to ream down casing, 2. imposing dog-leg into casing and thereby causing greater casing wear, 3. increase chance of pack-off while circulating and cementing, 4. increase the number of connections in the casing string (because centralizer subs often the only option for centralization), and 5. Damage to wellhead components (due to centralizer pass through).	6) Provide adequate centralization and/or other methods to aid proper cementation, to meet well design objectives within the constraints imposed by hydraulic, operational, logistical or well architecture limitations (ref. Standard 65-2 2nd Edition Appendix D1)
§250.420(b)(4)	(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.		Accept proposed text

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.420(c)(1)	(1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations.	Industry agrees with the language as written, but would like to ensure that ability to still obtain approval on short liners (< 500 ft.) is still available on a case by case basis.	
§250.420(c)(2)	(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.	This requirement is unclear and needs clarification if the center of the well must be overbalanced or the annular side of the well must be overbalanced. (For further discussion see Attachment E.) 1. Current best practice, when applied correctly, indicates that this is generally not necessary in deepwater .2. This may be a rule that is appropriate in a small percentage of applications and the rule should be clarified to identify those and make it applicable to only those. 3. It will result in promoting minimal cement fill (which will lead to unintended consequences of more potential of cross flow between zones left uncovered by cement and more potential for drilling induced buckling which will increase casing wear).	**If** this refers to the center of the well, then the following is proposed: "You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless or diverter hole sections." If this refers to the annular side then the committee takes exception and suggests not adding the text based on the attached documents and computer modeling. (Attachment F and G)
§250.421(b)	Casing type: Conductor; Casing requirements; Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone	Industry understanding is that for deepwater applications, 22" & 20" casing is considered surface pipe. If this understanding is not correct, then we take exception.	
§250.421(b)(1)	Casing type: Conductor; Cementing requirements Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.	Industry understanding is that drivepipe and jetted pipe are considered structural pipe. If this is not correct then we take exception.	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.421(f)	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing.	The committee was concerned with how casing would be treated in deepwater riserless operations. By providing the two additional requirements of top above mudline and cement back to the mudline, it feels like BSEE's intent can still be met without harming the industry.	Casing type: Liners Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A casing string whose top is above the mudline and that has been cemented back to the mudline will be not considered a liner.
§250.423	You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.		Accept proposed text
§250.423(a)	(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string.	Leave the language as it is currently codified. The proposed language change does not define success or how to measure it.	(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string.
§250.423(b)	(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner.	Leave the language as it is currently codified. The proposed language change does not define success or how to measure it.	(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of the liner.
§250.423(c)	(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners. (1) You must submit for approval with your APD, test procedures and criteria for a successful test. (2) You must document all your test results and make them available to BSEE upon request.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.427(b)	(b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.	When combined with 250.414c(2), c(3) and c(4) this rule will become an issue. The 0.5 ppg safe drilling margin added to the restriction of the pore pressure mud weight and ECD requirements will severely limit current and future drilling operations. The joint industry task force identified 110 wells (out of 175 wells reviewed - 63%) that were drilled safely after June 2010 which would not be considered drillable as originally designed if following BSEE proposed rules and practices (Lost circulation or insufficient mud margin). It is important to note that some of these wells might still be drillable if their casing designs were modified, but changing the design of these wells could make them uneconomic to complete as a result of smaller completions, possibly resulting in uneconomical production rates. Depleted zone sidetracks will be affected as most are restricted as to additional casing strings being available. Stopping drilling to set pipe based solely on a legacy (shallow shelf wells) drilling margin will have severe negative consequences for many of the deepwater or depleted zone wells being drilled today and in the future. In addition, containment requirements hinder many deeper well designs such that they no longer have the capability to run additional casing strings. The end result could be a decision to not drill these wells if they are uneconomic to complete and produce. Many of the deeper wells and shallow sidetrack wells have no additional casing options.	(b)The safe drilling margin shall be based on accepted industry practices as documented in API 92L. If a safe drilling margin cannot be maintained then remedial procedures shall be implemented, once risk assessed by the operator and approved by BSEE.
§250.428(b)	**<u>If you encounter the following situation:</u>** (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations, **<u>Then you must…</u>** Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.428(c)	**<u>If you encounter the following situation:</u>** (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment), **<u>Then you must…</u>** (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.	In many applications there are many planned lost return cement jobs that are successful.	**<u>If you encounter the following situation:</u>** (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline, cement channeling, or failure of equipment), **<u>Then you must…</u>** (1) Locate the top of cement by: (i) Lift pressure analysis; (ii) Running a temperature survey; (iii) Running a cement evaluation log; or (iv) Use radioactive tracer in cement and logged with LWD when TIH to drill out, (v) drill out and confirm integrity with a shoe test; or (vi) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
§250.428(d)	**<u>If you encounter the following situation:</u>** (d) Inadequate cement job, **<u>Then you must…</u>** Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.	A revised PE certification should only be required if the effectiveness of a barrier has changed. If the effectiveness of a barrier has changed the change should be certified by a PE.	**<u>If you encounter the following situation:</u>** (d) Inadequate cement job, **<u>Then you must…</u>** Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the casing or cement program that can impact the effectiveness of the barrier will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.428(k)	If you encounter the following situation: (k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner, **Then you must…** Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.		Accept proposed text
§250.462	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.	Access to Containment Consortium equipment and Mutual Aid Equipment.	What are the source control and containment requirements? For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor or approved alternate method.
§250.462(a)	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.	L1/L2 screening tool is supplied with all permits..	(a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to verify that a full shut-in can be achieved without having reservoir fluids broach to the sea floor. (3) If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.462(b)	(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.	It is industry's understanding that a containment dome is the equivalent of a "top hat" Change "top hat " to "localized , non - pressurized , subsea fluids collection device" . Add "Unless an alternate solution that meets or exceeds the capability of current equipment described below before the "This equipment must include..."	(b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system (where applicable as per 250.462(a)(3)), containment dome (i.e. localized , non - pressurized , subsea fluids collection device) , or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment. Unless an alternate solution that meets or exceeds the capability of the equipment described below. This must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.
§250.462(c)	(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.	This is submitted with each permit (RP checklist). An approved Regional Containment Demonstration would satisfy this requirement.	(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor or approved alternate method, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.
§250.462(d)	(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.	The proposed requirement to advise BSEE for any well design change will necessitate an undue burden on both the operator and BSEE. This is at a time when BSEE is already somewhat undermanned. Thus it is important to designate that only well design changes which negatively impact the results of the WCST require notification to BSEE.	(d) You must contact the District Manager or Regional Supervisor for reevaluation of your source control and containment capabilities if: (1) any changes in the well design or well conditions that require a revised permit to drill to be submitted and can impact the results of the well containment screening tool, or (2) Approved source control and containment equipment is out of service.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.462(e)(1)	**Equipment** (1) Capping stacks, **Requirements, you must:** (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests), **Additional information:** Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned. **Requirements, you must:** (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization, **Additional information:** Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves. **Requirements, you must:** (iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	The proposed regulation is not anticipating development of alternative testing methods and frequencies which will provide an equivalent or greater degree of verification. Additionally suggest that BSEE adopt the API terminology of "pressure containing" rather than use "pressure holding" to mitigate the possibility of misinterpretation. Finally, the proposed requirement that both BSEE and a BAVO witness pressure testing is superfluous and does not recognize the scarcity of human resources.	Equipment (1) Capping stacks, Requirements, you must: (i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests) or as otherwise approved by the Regional Supervisor for an alternative testing frequency. Requirements, you must: (ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test, or as otherwise approved by the Regional Supervisor for an alternative testing frequency. All pressure testing must be witnessed by BSEE and/or an independent third party, Additional information: Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves. Requirements, you must: (iii) Notify BSEE at least 21 days prior to commencing any pressure testing.
§250.462(e)(2)	**Equipment:** (2) Production Safety Systems used for flow and capture operations, **Requirements, you must:** (i) Meet or exceed the requirements set forth in 30 CFR 250.800-250.808, Subpart H, (ii) Have all equipment unique to containment operations available for inspection at all times.		Equipment: (2) Production Safety Systems used for flow and capture operations, Requirements, you must: (i) Meet the requirements set forth in 30 CFR 250.800-250.808, Subpart H, excluding equipment requirements below the wellhead or that are not applicable to the cap and flow system. (ii) Have all equipment unique to containment operations available for inspection at all times.
§250.462(e)(3)	**Equipment: (3)** Subsea utility equipment, **Requirements, you must:** Have all equipment unique to containment operations available for inspection at all times. **Additional information** Subsea utility equipment includes, but is not limited to: hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.	The phrase "available for inspection" needs clarification. Debris Removal tooling is provided by the suppliers HPU, Coil Tubing, pumping systems provided by supplier. Companies have contracts with these vendors to provide equipment but do not put specific equipment on retainer.	Equipment: (3) Subsea utility equipment, Requirements, you must: Have all equipment utilized uniquely for containment operations available for inspection at all times.
§250.465(b)(3)	Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE–0125, as required under § 250.744.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.500	Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.		Accept proposed text
§ 250.514	In § 250.514, remove paragraph (d).		
§250.518(e)	(e) Installed packers and bridge plugs must meet the following: (1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)	Does not apply to temporary packers and bridge plugs, such as used in well servicing applications	(e) After the effective date of this regulation, permanently installed (as defined in the APD and/or APM) packers and bridge plugs must meet the following: (1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)
§250.518(e)(2)	(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;	This requirement may compromise well objectives, compromise optimum reservoir recovery, and add risk in some situations. The perceived risk/benefit driving this new requirement is very limited and not necessary or warranted for broad application. It should also be noted that this new requirement and others related to packers may limit, not allow for, or are not applicable for tubingless completions (which can optimize reservoir recovery or add reserves by making uneconomic reserves economic).	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(e)(3)	(3) The production packer must be set as close as practically possible to the perforated interval; and	The term "as close as practically possible" is unclear, undefined and subject to varying interpretation, making it difficult to comply with. Some completion tools/methods require a certain distance between top perf and packer. In the case of a short or small production liner, it may be highly desirable (improve well reliability and increase reservoir recovery) to place the production packer in the casing just above the production liner.	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(e)(4)	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.	This requirement may compromise well objectives, compromise optimum reservoir recovery, and may add risk, such as when it is preferable to have an uncemented production liner lap and set the production packer within the lap, or when using electric submersible pumps (or other pump) at intermediate to shallow depths in the well.	The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.518(f)	(f) Your APM must include a description and calculations for how you determined the production packer setting depth.		(f) Your APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.600	Well-workover operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.		
§250.619(e)	(e) If you pull and reinstall packers and bridge plugs, you must meet the following:	Does not apply to temporary packers and bridge plugs, such as used in well servicing applications	(e) After the effective date of this regulation, permanently installed (as defined in the APD and/or APM) packers and bridge plugs must meet the following:
§250.619(e)(1)	(1) All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);		Accept proposed text
§250.619(e)(2)	(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer during well completion operations that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;	This requirement may compromise well objectives, compromise optimum reservoir recovery, and add risk in some situations. The perceived risk/benefit driving this new requirement is very limited and not necessary or warranted for broad application If this proposed rule requires packer fluid to compensate for a loss of riser margin, in many deepwater cases the wells could not be completed. The density of the packer fluid would not be capable of providing the necessary hydrostatic pressure to compensate for the loss of hydrostatic. The current language doesn't take into consideration future completion plans.	(2) The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment
§250.619(e)(3)	(3) The production packer must be set as close as practically possible to the perforated interval; and	The term "as close as practically possible" is unclear, undefined and subject to varying interpretation, making it difficult to comply with. Some completion tools/methods require a certain distance between top perf and packer. In the case of a short or small production liner, it may be highly desirable (improve well reliability and increase reservoir recovery) to place the production packer in the casing just above the production liner.	(3)The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.619(e)(4)	(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.	Establishing cement bond via remedial primary cementing can be operationally challenging and extremely costly. The process always requires the perforating of the primary well containment (production casing). Additional steps are required to ensure the primary well containment has not been compromised following the squeeze operations (e.g., squeeze perforations should be tested both positive and negative, which can be difficult to achieve and establishing acceptance / rejection criteria is difficult). Often times an additional production packer is set above the squeeze perforations in order to ensure the exposed perforations do not leak later in life.	(4) The production packer must be set as close as practically possible to the perforated interval. You must ensure that packer setting depth will ensure well integrity for life of well operations including production, intervention and abandonment.
§250.619(f)	(f) Your APM must include a description and calculations for how you determined the production packer setting depth.		(f) Your APM must include a description and calculations for how you determined the production packer setting depth and packer fluid selection.
§250.700	This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this Part unless explicitly stated otherwise.		Accept proposed text
§250.701	You may use alternate procedures or equipment during operations after receiving approval as described in § 250.141 of this Part. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE–0123) (see § 250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE-0124). Procedures for obtaining approval of alternate procedures or equipment are described in § 250.141 of this part.	Consistency between BSEE Districts on the interpretation and what is acceptable in District and not in the other.	
§250.702	May I obtain departures from these requirements? You may apply for a departure from these requirements as described in § 250.142. Your request must include justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM	BSEE will require justification for departures. This could result in increasing time burden with no technical benefit. A statement will still ensure operator responsibility.	You may apply for a departure from these requirements as described in § 250.142. Your request must include a statement showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see § 250.414(h)) or your APM.
§250.703	What must I do to keep wells under control? You must take necessary precautions to keep wells under control at all times, including:		Accept proposed text
§250.703(a)	(a) Use recognized engineering practices that reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;		Accept proposed text
§250.703(b)	(b) Have a person onsite during operations who represents your interests and can fulfill your responsibilities;		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.703(c)	(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;		Accept proposed text
§250.703(d)	(d) Use personnel trained according to the provisions of Subparts O and S;		Accept proposed text
§250.703(e)	(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment; and		Accept proposed text
§250.703(f)	(f) Use equipment that has been designed, tested, and rated for the most extreme service conditions to which it will be exposed while in service.	Unclear requirements	(f) Select equipment that is designed and rated for the anticipated conditions to which it will be exposed while in service.
§250.710	Prior to engaging in well operations, personnel must be instructed in:		
§250.710(a)	(a) The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by Subpart S of this Part. Date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.		
§250.710(b)	(b) Well-control. You must prepare a well-control plan for each well. Each well control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.		
§250.711	You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well control plan required by § 250.710.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.711(a)	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively.	Overly prescriptive. Drill should be appropriate for the operations conducted. Revised to be more appropriate for operations being conducted. The restriction on repetition of a drill is inappropriate. Drills are training exercises intended to reinforce procedures, and it may be desirable and appropriate to repeat a drill until a successful outcome is achieved.	(a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping and be appropriate for current operations.
§250.711(b)	(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report: (1) Date, time, and type of drill conducted; (2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and (3) The total time to complete the entire drill.		
§250.711(c)	(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.		
§250.712(a)	(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE-0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or (3) The departure of a rig unit from the location.	Note that this change in the reporting requirement from 24 hour notice to 72 hour notice will likely result in increased inaccurate estimates of operational moves of various unit and rig types due to the potential for operational plans, schedules or sequences to change over these extended time periods. This is likely to result in multiple reporting adjustments being made to BSEE during the anticipated reporting periods. Recommend that this reporting notice be reduced to 48 hours versus the currently proposed 72 hour timeframe. 48 hours is consistent with USCG notification for MODUs.	(a) Prior to commencing operations and at the completion of operations, you must report the movement of all drilling units on and off drilling locations to the District Manager. This includes both MODU and platform rigs. (1) You must inform the District Manager 48 hours before: (i) Prior to commencement of operations, the arrival of an MODU on location; and (ii) at the completion of operations, the departure of an MODU from the location. (2) You must inform the District Manager 24 hours before: (i) The movement of a platform rig to a platform; (ii) The movement of a platform rig to another slot; and (iii) The movement of an MODU to another slot.
§250.712(b)	(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.		
§250.712(c)	(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager; (1) Where the MODU or platform rig is coming from; (2) The location of where the MODU or platform rig will be positioned; (3) Whether the MODU or platform rig will be manned or unmanned; and (4) If the location for stacking the MODU or platform rig changes.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.712(d)	(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig;		
§250.712(e)	(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.		
§250.712(f)	(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE-0144, Rig Movement Notification Report.		
§250.713	If you plan to use a MODU or lift boat for well operations, you must provide:		
§250.713(a)	(a) Fitness requirements. Information and data to demonstrate the capability to perform at the proposed location. This information must include the most extreme environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD or APM, the District Manager may approve your APD or APM but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD or APM if information collected during operations shows that the MODU or lift boat is not capable of performing at the proposed location.		
§250.713(b)	(b) *Foundation requirements.* Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed MODU or lift boat. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, lift boat, or equipment installed on a subsea wellhead. For moored rigs, you must submit a plat of the rigs' anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.713(c)	(c) For frontier areas. (1) If the design of the MODU or lift boat you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU or lift boat design. If required, you must obtain a third-party review of your MODU or lift boat similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM. (2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU or lift boat. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of operations to remedy various operational or environmental situations (e.g., vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).		
§250.713(d)	(d) *Additional documentation.* You must provide the current Certificate of Inspection (for US Flagged vessels) or Certificate of Compliance (for Foreign Flagged vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.		
§250.713(e)	(e) Dynamically positioned rig unit. If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. Your plan must include, but not be limited to, such emergency events caused by storms, currents, station-keeping failure, power failure, and loss of well-control. The District Manager may require your plan to include additional events and information.		
§250.713(f)	(f) Inspection of unit. The MODU or lift boat must be available for inspection by the District Manager before commencing operations and at any time during operations.		
§250.713(g)	(g) Current Monitoring. For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM: (1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and (2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.		

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§250.714	If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:		
§250.714(a)	(a) A description and plot of the path the rig will take while running and pulling the riser;		
§250.714(b)	(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;		
§250.714(c)	(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (*e.g.,* riser or casing) and box (*e.g.,* BOP or tree);		
§250.714(d)	(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and	Companies should have SIMOPS procedures in place	
§250.714(e)	(e) Any additional information required by the District Manager.		
§250.715	All jack-up and moored MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to each hurricane season.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(a)	(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the moored MODU or jack-up moves from its location during a severe storm.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(b)	(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(c)	(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(d)	(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(e)	(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	
§250.715(f)	(f) Contact the Regional Office and allow real-time access to the MODU or jack-up location data. When you contact the Regional Office, provide the following: (1) Name of lessee and operator with contact information; (2) Rig/facility/platform name; (3) Initial date and time; and (4) How you provided GPS real-time access.	New regulation requiring transmission of position data onshore that would be accessed by BSEE	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.720(a)	(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with § 250.721. (1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following: (i) Evacuation of the rig crew; (ii) Inability to keep the rig on location; (iii) Repair to major rig or well-control equipment; or (iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling). (2) The District Manager may approve alternate procedures or barriers in accordance with § 250.141 if you do not have time to install the required barriers or if special circumstances occur.		Accept proposed text
§250.721(a)	(a) You must test each casing string that extends to the wellhead according to the following table:		Accept proposed text
§250.721(a)(1)	Casing type: (1) Drive or Structural, Minimum test Pressure: Not required.		Accept proposed text
§250.721(a)(2)	Casing type: (2) Conductor, excluding subsea wellheads. Minimum test Pressure: 250 psi.		Accept proposed text
§250.721(a)(3)	Casing type: (3) Surface, Intermediate, and Production, Minimum test Pressure: 70 percent of its minimum internal yield.		Accept proposed text
§250.721(b)	(b) You must test each drilling liner and liner-lap to a pressure at least equal to the anticipated leak off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.	Testing of the liner-lap is not possible. The liner-top can be tested to confirm integrity.	(a) You must test each drilling liner (and liner-top) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Manager may approve or require other liner test pressures.
§250.721(c)	(c) You must test each production liner and liner-lap to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.	Testing of the liner-lap is not possible. The liner-top can be tested to confirm integrity	(c) You must test each production liner (and liner-top) to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped
§250.721(d)	(d) The District Manager may approve or require other casing test pressures.		Accept proposed text

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.721(e)	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.	The proposed language to "pressure test the entire well to maximum anticipated shut-in tubing pressure" is not clearly defined and subject to interpretation. It is not clear if "anticipated shut-in tubing pressure" is with full column of HC or after perforating with an underbalanced fluid. If the context is with full column of HC, it is problematic to implement this when the fluid in the well at time of pressure test is different density than the planned completion fluid. In this situation, the proposed new rule applied literally could require multiple pressure tests with a test packer set at different depth for each test. This could add risk due to multiple pressure tests, inducing multiple stress cycles on the casing and the cement to casing bond, increase the chance of casing failure later in life of the well, and/or increase chance of forming a microannlus. The proposed language would also very likely result in higher test pressure for many wells, particularly high pressure wells, and this would induce greater stress on the casing and casing to cement bond, further increase the chance of casing failure later in life of well, and/or increase the chance of forming a microannulus. Besides the potential unintended negative consequences mentioned above, the historical requirement to test to maximum anticipated SITP, but not to exceed 70% of burst rating, has proven effective and should be continued (the 70% burst rating limit, as practiced, prevents the potential issues mentioned above).	(e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of the burst rating limit of the weakest component, before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, but not to exceed 70% of the burst rating of the weakest component, before you drill the open-hole section.
§250.721(f)	(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.		Accept proposed text
§250.721(g)	(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.		Accept proposed text
§250.721(g)(1)	(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.		(1) If hydrocarbons are present, you must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track but prior to conducting any completion operations.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.721(g)(2)	(2) You must perform a negative test prior to unlatching the BOP at any point in the well. The negative test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.		Accept proposed text
§250.721(g)(3)	(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack.		Accept proposed text
§250.721(g)(4)	(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.		Accept proposed text
§250.721(g)(5)	(5) You must document all your test results and make them available to BSEE upon request.		Accept proposed text
§250.721(g)(6)	(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must: (i) Correct the problem and immediately notify the appropriate BSEE District Manager and (ii) Submit a description of the corrective action taken and receive approval from the appropriate BSEE District Manager for the retest.		Accept proposed text
§250.721(g)(7)	(7) You must have two barriers in place, as described in § 250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.		(7) If hydrocarbons are present, you must have two barriers in place, as described in § 250.420(b)(3), prior to performing the negative pressure test.
§250.721(g)(8)	(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE-0125).		Accept proposed text
§250.722	If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test or BSEE approved verification of the well's casing or liner, you must:		If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test or independent third party review of the well's casing or liner, you must:

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.722(a)	(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must: (1) Evaluate the well's casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors.		(a) Stop operations as soon as practicable, and evaluate the effects of the prolonged operations on continued operations and the life of the well. At a minimum, you must: (1) Evaluate the well's casing with either a pressure test, caliper tool, or imaging tool. On a case-by-case basis the District Manager may require a specific method of evaluation; and (2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. If an imaging tool or caliper is used, then your report must include calculations that show the well's integrity is above the minimum safety factors.
§250.722(b)	(b) If well integrity has deteriorated to a level below minimum safety factors, you must: (1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes; (2) Repair the casing or run another casing string; and (3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in § 250.721.		Accept proposed text
§250.723	You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:		
§250.723(a)	(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;		
§250.723(b)	(b) You must install an emergency shutdown station for the production system near the rig operator's console;		
§250.723(c)	(c) You must shut-in all producible wells located in the affected wellbay below the surface and at the wellhead when: (1) You move a rig unit or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform; (2) You move or skid a rig unit between wells on a platform; and (3) A MODU or lift boat moves within 500 feet of a platform. You may resume production once the MODU or lift boat is in place, secured, and ready to begin operations.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.723(d)	(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment unless otherwise approved by the District Manager. (1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. (2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system. (3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.		
§250.723(e)	(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.		
§250.724	(see Preamble)	This requires operators to monitor Deepwater and HPHT operations in Real Time. Smaller Operators may not be able to implement in this time frame along with having cost issues.. BSEE has not sufficiently justified the use of real-time monitoring and its potential effect on safety. Unknown what degree of real-time monitoring is required to ensure functionality and operability is sufficient to meet BSEE expectations. Current capability may need to be upgraded. More economic analysis is required to obtain valid numbers. Real time system can't easily be turned on and off, it requires increased communication capability, and people to operate it expect to work year round. Real cost is significantly higher which affects smaller operator. Once installed, a remote RTC is a fixed operating cost that can be allocated as per the number of operations. The cost is still there regardless if there are operations. A minimum daily operating cost for a remote RTC is $40,000. This is exclusive of the set up charge for the facility and monthly cost for the facility.	

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.724(a)	(a) When conducting well operations with a subsea BOP or surface BOP on a floating facility, or when operating in an HPHT environment, you must, within 3 years of publication of the final rule, gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting all aspects of; (1) The BOP control system; (2) The well's fluid handling systems on the rig; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized. Define parameters to be monitored. Data collection points to be added to subsea discrete and surface BOP systems. Adds pressure temperature probes to the stack. Bandwidth and reliability is not reliable due to weather, crane movements, and the service provider. Significant cost to develop and integrate into existing systems. Possible entry point into a safety system for attack or virus. Cyber security would be required. Not all companies have a real time operations center or the staff to support one.	Remove §250.724(a, b, c) If not removed, change to: (a) When conducting well operations with a subsea BOP or surface BOP on a floating facility, or when operating in an HPHT environment, you must gather and monitor real-time well data using a system capable of recording, storing, and transmitting data as identified in a Real Time Monitoring Plan. Within 3 years of publication of the final rule, the Real Time Monitoring Plan must address (1) the fluid circulating system and (2) bottom hole tools. Within 5 years of publication of the final rule, the Real Time Monitoring Plan must address the BOP status.
§250.724(b)	(b) You must immediately transmit these data as they are gathered to a designated onshore location during operations where they must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations. After operations, you must preserve and store this data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must designate the location where the data will be stored and monitored during operations in your APD or APM. The location and the data must be made accessible to BSEE upon request.	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.	Remove §250.724(a, b, c) If not removed, change to (b) During well operations, real-time data must be transmitted to a designated onshore location and the data must be monitored by qualified personnel, as defined in the Real Time Monitoring Plan. Where defined in the Real Time Monitoring Plan, the onshore monitoring personnel must have the capabilities to communicate with rig personnel during operations. After operations, the data must be preserved and stored at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. The location and the data must be made accessible to BSEE upon request.
§250.724(c)	(c) If you lose any real-time monitoring capability during operations covered by this section, you must immediately notify the District Manager. The District Manager may require other measures until real-time monitoring capability is restored.	Rulemaking on RTM is premature. BSEE has contracted the Transportation Research Board of the National Academies to advise the agency on the use of real-time monitoring systems by industry and government. The final report of the Transportation Research Board should be fully considered by BSEE and the public before any rulemaking on RTM is finalized.	Remove §250.724(a, b, c) If not removed, change to (c) The Real Time Monitoring Plan must define a protocol if real-time monitoring capabilities are lost during operations covered by this section.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(a)	(a) You must design, install, maintain, inspect, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter. Your BOP system must meet the following requirements:	Exclude components above the uppermost ram preventer (e.g.. annular and LMRP or riser connect.) Replace "design" with "select." Annular BOPs capable of meeting the specified pressure rating are not available and are not considered technologically feasible in the near term. Limit this regulation to lower stack components including and below the uppermost ram. Empirically, industry has demonstrated the capability to successfully seal the wellbore under a variety of flowing conditions, e.g., flow checks using an annular BOP. However, the proposed regulation, as drafted, calls for each ram to be assessed against an absolute worst case design level event. The goal should be for the BOP system to reliably shut-in the well under reasonably anticipated flowing conditions. Criteria for such anticipated flowing conditions are not presently defined. Industry proposes establishing a working group to work with BSEE to establish industry guidelines for future qualification of BOP system performance under flowing conditions, based on data available from BSEE and industry sources. Industry proposes establishing a working group to work with BSEE to establish industry guidelines for future qualification of BOP performance under flowing conditions, based on data available from BSEE and industry sources	250.730 (a) You must select, install, maintain, inspect, test, and use the BOP system and system components to ensure well-control. The working-pressure rating of each BOP component (ram BOP, gate valve, choke and kill, and wellhead connector) must exceed MAWHP as defined for the operation. For a subsea BOP, the MAWHP must be taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore for each well under the anticipated flowing conditions for annular and ram sealability as defined in the APD, and will be based on early detection, for the operation and specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that you may encounter. Your BOP system must meet the following requirements:
§250.730(a)(1)	(1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart.	API 53 was agreed by industry but the WCR obfuscates the interpretation of the standard Corresponding incorporation by reference of dated equipment manufacturing standards is problematic as it renders equipment manufactured prior to the standard, or to earlier version of the standards obsolete. No justification has been given for such action. The equipment is manufactured to the edition in publication at the time of manufacture. Reference API 53 only and that document will lead to the revised language in the next edition to close this gap.	API 53 in its entirety applies. With regards to dated references, only the relevant provisions of those references apply. The applicable editions of dated references should be those in effect at the date of manufacture of the specific equipment.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(a)(2)	(2) The following industry standards (all incorporated by reference in § 250.198): (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A; (iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D.	BSEE needs to provide guidelines on the intended use for referencing these standards	Reference API 53 in its entirety with regards to 6A, 16A, 16C, 16D, and 17D, such that only the relevant provisions of those references apply. The editions of API 6A, 16A, 16C, 16D, and 17D should be those that were in effect at the date of manufacture of the specific equipment.
§250.730(a)(3)	§250.730(a)(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.	With control lines etc. – this isn't achievable. This is a show-stopper for running tubing. Need clarification regarding "proposed regulator settings" as this potentially conflicts with API 53. Understanding regulator setting requirements will help industry proposed text that will be better	(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole as defined by the operation. For tubing with control lines, flat packs, or other auxiliary equipment strapped to the tube and across the BOP, a risk assessment shall be used to mitigate well flow risks and to implement control measures for BOP shut-in if required. Regulator settings for ram preventers will be adjusted above normal operating pressure if shut in conditions warrant
§250.730(a)(4)	250.730.(a)(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.		Accept proposed text
§250.730(b)	250.730(b) You must design, fabricate, maintain, and repair your BOP system according to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.	Recommend replace "design and fabricated" with "select." Second sentence isn't viable as OEMs do not presently publish T&Q recommendations. Equipment owner is already establishing standards IAW SEMS and Subpart O requirements. Definition of OEM should be clarified to indicate the component manufacturer or the system supplier	(b) You must select, maintain, and repair your BOP system according to the requirements contained in this subpart, API 53, and OEM recommendations unless otherwise directed by BSEE. The training and qualification of repair and maintenance personnel must be established in accordance with §250.1915 of this part and meet the requirements of §250.1503 of this part, unless otherwise directed by BSEE.
§250.730(c)	(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and:	BSEE needs to provide guidelines on the intended use for referencing these standards Spec 6A and 16A references should not be identified as the qualifying reference as they are manufacturing related failure reporting methods. API 53 is an operational document.	(c) You must follow the failure reporting procedures contained in API Standard 53 and:

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.730(c)(1)	(1) You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure.	The beta test group (7 drilling contractors) is already reporting all failures, which we define as the inability of the equipment to function as defined, to a common database. The database automatically copies the reports to the respective OEM fulfilling the requirements of API 53 and 250.730(c)	(1) You must ensure a written report of equipment failure is provided to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is defined as the inability of the equipment to function as required.
§250.730(c)(2)	(2) You must ensure that an investigation and a failure analysis are initiated within 60 days of the failure to determine the cause of the failure. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis.	Not every failure warrants a full investigation. Repeat failures warrant changes to the equipment, not repeat investigations.	(2) Within 60 days of a failure, you must ensure that an investigation is initiated to determine the cause of the failure. If the investigation is performed by an entity other than the manufacturer, you must ensure that the manufacturer receives the results of the investigation.
§250.730(c)(3)	(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed, or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.	This should be addressed under SEMS requirements (MOC); new version of API SPEC 16A is aligned with API 53. Question why this report is being sent to HQ office instead of the District Supervisor as the standard path listed in this rulemaking. Clarify which entity is required to notify BSEE (e.g., contractor or operator involved in the original failure).	(3) If the equipment manufacturer, or equipment owner, notifies you that the design, operating or repair procedures has changed as a result of the failure reference in § 250.730(c)(1) , then you must, within 30 days of such notice or change, report the design change or modified procedures in writing to the District Supervisor; Bureau of Safety and Environmental Enforcement ; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166
§250.730(d)	(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.	There is no API standard for a BOP stack. Spec. Q1 would apply only to the individual components. ISO 17011 is an incorrect reference. ISO 17021 is the correct reference that should be applied to organizations which certify that quality management systems meet the requirement of a particular reference.	(d) If you plan to use BOP equipment and components manufactured after the effective date of this regulation, you must use equipment and components manufactured under a quality management system certified to API Spec Q1 (as incorporated by reference in § 250.198). The entity certifying such quality management system must meet the requirements of ISO 17021.
§250.730(d)(1)	(1) The BSEE may consider accepting equipment manufactured under quality assurance programs other than API Spec. Q1, provided you submit a request to BSEE containing relevant information about the alternative program and receive BSEE approval under § 250.141.	ISO 9001:2015 and ISO TS29001 are perceived as inadequate in its fit-for-purpose application in this instance (ISO TS29001/API 8th edition contains 37 supplemental requirements beyond ISO 9001:2008 and API 9th edition contains 93 additional requirements beyond API 8th edition). If alternate QMS systems are used, user/purchasers have to invest time/resources to insure QMS meets the requirements of API Q1.	Accept proposed text
§250.730(d)(2)	(2) You must submit this request to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314: 45600 Woodland Road, Sterling, Virginia 20166.	See comments on §250.730(d)(1).	Delete this clause.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731	For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.		
§250.731(a)(1-9)	**You must submit:** (a) A complete description of the BOP system and system components, **Including:** (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).	Administrative burden.	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731(b)(1-10)	**You must submit:** (b) Schematic drawings, **Including:** (1) The inside diameter of the BOP stack, (2) Number and type of preventers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated valves of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.		**You must submit:** (b) Schematic drawings, **Including:** (1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731(c)	You must submit: (c) Certification by a BSEE-approved verification organization, Including: Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.	(1) Shear testing at water depth may imply the BOP is in an environment that simulates the required water depth instead of on surface as we currently do. Delete water depth text. (2) The most extreme conditions could mean shear testing with RWP in the wellbore or under flowing conditions. This is not practical or safe to do in a lab. Delete extreme conditions text. (3) Current protocol API 53 addresses the operational side however; this language indicates an impact on S16A and 16D The "most extreme" anticipated conditions needs definition Flow isn't part of the manufacturer's design parameters. Refer back to 250.198 for design parameters. BAVOs don't currently exist and could result in a potential bottleneck. "Test data" implies that a shearing test must be provided for each configuration. Clarification of BSEE's intent is required. API does not address Extreme Conditions. API 53 does identify operations and maintenance. Not to be considered for Spec upgrades because we are unable to identify "extreme anticipated conditions". Industry has addressed the issues for volume requirements. There is a conflict between what BSEE has required and what API 53 and the current work in the specifications are working toward. Coiled tubing and other referenced operations will be greatly impacted if they have to incorporate the BOP specifications. Putting the same requirements on CT operations (response times) will negatively impact CT operational safety.	You must submit: (c) Certification by a qualified independent third party, Including: Verification that: (1) Test data and supporting engineering calculations clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions as defined in the APD and/or APM; and (3) The accumulator system is in accordance with API 53.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.731(d)	250.731(d) You must submit: (d) Additional certification by a BSEE-approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.	BOP stacks aren't designed for specific equipment on a rig: Rather, they are selected in consideration of such equipment. Change to "is suitable for use with" BAVOs don't currently exist. Can a BAVO certify that a stack has not been compromised from previous service?	You must submit: (d) Additional certification by a third party organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. Including: Verification that: (1) The BOP stack is suitable for use with the specific equipment on the rig and for the specific well design; (2) The BOP stack's ability to function as required has not been compromised from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.
§250.731(e)	You must submit: (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, Including: A listing of the functions with their sequences and timing.	Additional Burden. Add "if installed" after EDS systems.	You must submit: (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems if installed, Including: A listing of the functions with their sequences and timing.
§250.731(f)	You must submit: (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	Assume this is only required if an APD/APM has not been submitted in the previous 12 months. If it is addition too then it appears to be an unnecessary time and expense burden.	You must submit: (f) Certification stating that the BOP and Well Compatibility Certificate, as required in an APD/APM has been submitted to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, within the past 12 months.
§250.732	What are the BSEE-approved verification organization requirements for BOP systems and system components?	Adversely affects rigs that work overseas. Issue exist to operate in the GOM if equipment is not "monitored during its entire lifecycle". Recertification may not be economical and technically impractical to achieve.	What are the independent third-party requirements for BOP systems and system components?
§250.732(a)	(a) The BSEE will maintain a list of BSEE-approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:	If retained in the rule, §250.732(a) should not go into effect until 12 months after the initial BSEE-approved Verification Organization list is published.	(a) In independent third party providing certification or verification services under subparts D and G of this part must have:
§250.732(a)(1)	(1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;	The requisite experience is in the verification of the design.	(1) Previous experience in verification of the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment
§250.732(a)(2)	(2) Technical capabilities;		Remove
§250.732(a)(3)	(3) Size and type of organization;		Remove
§250.732(a)(4)	(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;		Renumber

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§250.732(a)(5)	(5) Ability to perform the verification functions for projects considering current commitments;		Renumber
§250.732(a)(6)	(6) Previous experience with BSEE requirements and procedures; and		Renumber
§250.732(a)(7)	(7) Any additional information that may be relevant to BSEE's review.		Remove
§250.732(b)	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE-approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.	"	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party and supporting documentation as required by this paragraph to the appropriate District Manager.
§250.732(b)(1)i	You must submit verification and documentation related to: (1) Shear testing, That: (i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, slick-line to be used in the well;	As written, this would shut down many drilling operations for a long period as many rigs do not currently have shearing capability that would conform in regard to the electric-, wire-, slick-line requirement. Replace BOP with shear ram to confirm it doesn't need to be specific to a particular BOP assembly Extend the requirement for Non-drill pipe to 5 years (e.g., wire-line)	You must submit verification and documentation from an independent third party related to: Shear testing, That: (i)(a) Demonstrates that the required sealing shear ram will shear the drill pipe to be used in the well; (i)(b) Demonstrates that the required sealing shear ram will also shear any electric, wire, slick-line in the well within 5 years.
§250.732(b)(1)ii	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices to ensure repeatability, reproducibility of the test, and that the testing was performed by a facility that meets generally accepted quality assurance standards;	This wording is vague and unclear. It would be very difficult to know when/if conformance was achieved.	
§250.732(b)(1)ii i	(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;	The actual shear testing should be in accordance with current industry standards only. This includes shearing the drill pipe with zero wellbore pressure and zero tension. There is a safety risk when shearing a drill pipe in the lab with high pressure in the wellbore and flowing conditions. Moreover, it is not practical to perform shear tests this way. The calculations consider the field application, taking into consideration the mechanical properties of the drill pipe and loading conditions. Effects of wellbore pressure on shear pressure should be calculated and be included in the test report. (iii) Was conducted at zero wellbore pressure and no tension or compression in the drill pipe.	(iii) Was conducted at zero wellbore pressure and no tension or compression in the drill pipe.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.732(b)(1)iv	(iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16);	Remove the section of "performed on the outmost edges" and is performed as required in 250.734(a)(16) Inconsistent with other section, § 250.734(a)(16)(i), that allows 7 years for pipe centering technology to be developed. Justification for performing this shear testing prior to the 7 years before the pipe centering requirement is in effect has not been made. (iv) Ensures that the test demonstrates off-center pipe shearing capability within the time period referenced in § 250.734(a)(16)(i);	(iv) Ensures that the test demonstrates off-center pipe shearing capability within the time period referenced in § 250.734(a)(16)(i);
§250.732(b)(1)v	(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and	Specify drill pipe for use in the well. (v) Demonstrates the shearing capability of the BOP equipment to the physical and mechanical properties of the drill pipe to be used in the well; and	(v) Demonstrates the shearing capability of the BOP equipment relative to the physical and mechanical properties of the drill pipe to be used in the well; and
§250.732(b)(1)vi	(vi) Includes all testing results.	(vi) Includes relevant testing results.	(vi) Includes relevant testing results.
§250.732(b)(2)	You must submit verification and documentation related to: Pressure integrity testing and,That: (i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and (iii) Includes all test results.	Delete requirement for sealing pressure due to potential confusion offshore. Also, test pressure should be MASP/MAWHP, or the RWP of the sealing preventer above the uppermost shear ram, whichever is lower.	You must submit verification and documentation related to: (2) Pressure integrity testing and, That: (i) Shows that pressure testing is conducted before opening the shear rams; (ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP, as per the time requirements in the relevant industry standards; and (iii) Includes relevant test results.
§250.732(b)(3)	You must submit verification and documentation related to: (3) Calculations, That: Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.	BSR Verification Document - already doing. However, the 'sealing' component is an addition and we do not currently calculate the 'sealing' pressure for rams as this is more ambiguous and potentially misleading offshore.	You must submit verification and documentation related to: (3) Calculations, That: Include shearing pressures for all pipe to be used in the well including corrections for MASP/MAWHP, not to exceed the rated working pressure of the sealing preventer located directly above the uppermost shear ram.
§250.732(c)	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE-approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE-approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.	Change the wording of "access to any facility" to "access to documentation"	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by an independent third party that they conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third party access to any documentation associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager before you begin any operations in an HPHT environment with the proposed equipment

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.732(c)(1)	You must submit: (1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices		You must submit: (1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems, as defined in API 53, meet recognized engineering practices
§250.732(c)(2)	**You must submit:** (2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible. **Including: (**i) Identification of all reasonable potential modes of failure and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.	Recommend that the testing process refer to the appropriate validation testing required in industry specifications (e.g., API 16 A / 16 C / 16 D) There is no industry standard for the design of the overall system.	**You must submit:** (2) Verification that the designs of individual components have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible as required in appropriate industry standards. **Including: (**i) Identification of all reasonable potential modes of failure. and iii) Verification that the equipment designs have been assessed for the identified potential modes of failure. (iii) Evaluation of the design validation tests.
§250.732(c)(3)	**You must submit:** (3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered and,		
§250.732(c)(4)	**You must submit:** (4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms. **Including:** For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.	The phrase "complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage…" is overly broad and undefined. Complying with requirements for ALL contractors, subcontractors, distributors, and suppliers…….. at EVERY stage…… would take many years to comply with.	You must submit: (4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and established quality control and assurance mechanisms. Including: The quality control, assurance requirements and material documentation specified by the industry standard(s) for the components and systems.
§250.732(d)	(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE-approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia 20166. This report must include:	Recommend removing this section as all subparts are included in other existing or proposed CFR requirements, which are typically addressed on a frequency less than 12 months. As written, this would require considerable costs and resources with no additional benefits or reduction of risk.	Remove
§250.732(d)(1)	(1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.	Recommend removing this requirement as it duplicates the APD requirements	Remove

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.732(d)(2)	(2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(3)	(3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(4)	(4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(5)	(5) A description of the Safety and Environmental Mangement Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.	Recommend removing as it is currently covered in the current BSEE SEMS audits	Remove
§250.732(d)(6)	(6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems met recognized engineering practices and OEM requirements.	OEMs do not provide training requirements. Training and competency requirements addressed thru SEMS. Recognized engineering practices are addressed thru the applicable API standards and specifications.	Remove If not removed, change to and renumber: (6) would require that the personnel who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the equipment owner and that such maintenance, inspection, and repair be undertaken in accordance with API 53.
§250.732(d)(7)	(7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.	Recommend this requirement is added to the APD and remove from this section	Remove
§250.732(d)(8)	(8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(9)	(9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.	Need to clarify the term "critical components." Recommend removing this requirement as it duplicates the APD requirements	Remove If not removed, change to and renumber: (9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components as defined in API 53.
§250.732(d)(10)	(10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(11)	(11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.	Recommend removing this requirement as it duplicates the APD requirements	Remove

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.732(d)(12)	(12) Verification that any inspection, maintenance, or repair work met the manufacturer's design and material specifications.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(13)	(13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.	Recommend removing this requirement as it duplicates the APD requirements	Remove
§250.732(d)(14)	(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.	Recommend removing as this requirement should be included in §250.730(c)	Remove
§250.732(e)	(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.		Remove
§250.733(a)	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind-shear rams, and two BOPs equipped with pipe rams.	Too prescriptive. Ram placements and configurations should be established by the operator based on a risk assessment.	(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. A documented risk assessment shall be performed for all BOP arrangements to identify ram placements and configurations to be installed. The assessment shall include tapered strings, casings, completion equipment, test tools, etc.
§250.733(a)(1)	(1) The blind-shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind-shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.	The preamble does not exclude TJ, BHA, etc components, but page 21523 of the notice does reference tool joints. Needs clarification	
§250.733(a)(2)	(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.	See above regarding control lines	(2) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding control lines, flat packs, etc., where a risk assessment shall be used to identify additional mitigation measures) in the hole, as defined for the operation. Regulator settings will be adjusted above normal operating pressure as required.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.733(b)	(b) If you plan to use a surface BOP on a floating production facility you must:		
§250.733(b)(1)	(1) Follow the BOP requirements in §250.734(a)(1). You must comply with this requirement within 5 years from the publication of the final rule.	Refer to 250.734(a)(1) comments. To implement the changes on existing/producing facilities would involve shutdown and create greater risks than benefits	(1) Follow the BOP requirements in §250.734(a)(1). For floating production facilities, installed after the effective date of this rule, you must comply with this requirement. For existing floating production facilities risk assessments shall be submitted with the permit.
§250.733(b)(2)	(2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.	Clarification that existing facilities currently using single bore strings may continue to do so is needed In addition to dual casing (bore) TTRs, there are a few cases in the GoM where a single casing (bore) TTR concept were used. Suggest to stress dual barriers requirement for safety, which can be accommodated by either dual casing (bore) or split BOPs (surface BOP in combination with subsea isolation device). This is very important for future HPHT applications that we will be able to use "Dual Barrier" rather than Dual bore (single casing with shutdown valve).	(2) Use a dual bore riser configuration, for floating production facilities, installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.
§250.733(b)(2)(i)	(i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.	Suggest to replace "Clarify that the annulus between the risers must be monitored during operations" with "pressure monitoring	(j)For a dual bore riser configuration, pressure monitoring for annulus between outer casing and inner casing is required if outer casing is not designed with full rated wellhead tubing shut-in pressure. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.
§250.733(b)(2)(ii)	(ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.		
§250.733(c)	(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.		
§250.733(d)	(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.733(e)	250.733(e) You must install hydraulically operated locks.	3 Months is not achievable for rigs that do not have hydraulically operated locks and the BOP controls system. While hydraulically operated locks remove the operator from the vicinity they do not provide the reliability of a manual lock.	Delete requirement for surface BOPS and CWI for production floating units and surface BOPs for HPHT wells.
§250.733(f)	250.733(f) (f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE-approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and (2) Receive approval from the District Manager.		(f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised APD or APM including documentation of the repairs and documentation (statement-of-fact) from an independent third party stating that they reviewed the repairs, and that the BOP is fit for service; and (2) Receive approval from the District Manager.
§250.734(a)	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(1)(i -ii)	When operating with a subsea BOP system, you must: (1) Have at least five remote-controlled, hydraulically operated BOPs; Additional requirements You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear rams must be installed below the sealing shear rams.	Any non-sealing shear ram must be installed below at least one sealing shear ram. The rule should not exclude non-hydraulic BOPs. The 5-year implementation needs to extend beyond the "two shear ram requirement" to the applicability of the whole section in order to allow for the introduction of technology to allow for the shearing of flat packs, slickline, etc. General comment needs to be developed on MASP – Not to exceed the rated pressure of the sealing preventer above the uppermost shear ram. Discussion on use of MAWHP vs. MASP for both subsea and surface. MASP is not the appropriate term, as used by BSEE, for subsea.	You must comply with this requirement within 5 years from the publication of the final rule. When operating with a subsea BOP system, you must: (1) Have at least five remote-controlled, hydraulically operated BOPs; Additional requirements You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MAWHP, not to exceed the rated pressure of the sealing preventer above the uppermost shear ram, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole, under MAWHP, but not to exceed the rated pressure of the sealing preventer above the uppermost shear ram. At least one shear ram must be capable of sealing the wellbore after shearing under MAWHP conditions as defined for the operation. Any non-sealing shear rams must be installed below at least one set of the sealing shear rams.
§250.734(a)(2)	When operating with a subsea BOP system, you must: (2) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system;	Dual pod" is too prescriptive and may restrict alternatives. The objective is redundancy, which is already adequately addressed by API 53.	When operating with a subsea BOP system, you must: (2) Have a redundant control system to ensure proper and independent operation of the BOP system;

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(3)	When operating with a subsea BOP system, you must: (3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. Additional requirements The accumulator capacity must: (i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems. (iv) Perform under MASP conditions as defined for the operation.	There may be engineering changes needed for compliance. 90-day implementation may not be feasible.	When operating with a subsea BOP system, you must: (3) Have the accumulator capacity, to provide fast closure of the BOP components during normal operation and EDS. Further, have the accumulator capacity located subsea, to provide closure of the deadman and autoshear within the response times specified in API 53 in case of a loss of the power fluid connection to the surface. Additional requirements: Within 5 years of the publication of the final rule, the subsea accumulator capacity must be sufficient to: (i) Close each required shear ram. (ii) Have accumulator bottles that are dedicated to the emergency systems for both the autoshear and deadman.
§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).	This is a major change for some rigs as it exceeds the requirements of API 53. This is a requirement that is more germane to the LMRP than the ROV. Provision should be made to allow actual demonstration of stabbing into an ROV intervention panel on a subsea stack. E.g., add "or equivalent" at end of sentence. It is not clear if this is intended to require 24/7 ROV coverage. We interpret the language of: "The ROV must be capable . . . ." in the same manner that was discussed and included in API 53.	When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; The ROV must be capable of performing critical functions, as defined in API 53 7.4.16.1.1, under MAWHP 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).

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(5)	When operating with a subsea BOP system, you must: (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations; Additional requirements: The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.		When operating with a subsea BOP system, you must: (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must be familiar with all ROV related equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations; Additional requirements: The crew must be trained in the operation of the ROV. The training must include competence training on stabbing into an ROV intervention panel and operating the type(s) of ROV valves that are mounted on the BOP stack. The ROV crew must be able to be in constant communication with designated rig personnel who are knowledgeable about the BOP's capabilities whenever the ROV is deployed to the BOP stack.
§250.734(a)(6)	When operating with a subsea BOP system, you must: (6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs; Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation. (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.	Issue associated with timing sequence of shears. Emergency functions should be operations specific Separate EDS from other deadman and autoshear Clarifying intent of expected shearing and sealing expectation An operational risk assessment determines the optimum emergency sequence for the specific operation to be performed. And this is too prescriptive a requirement in the shearing sequential requirement (there are many differences between an EDS selected sequence and the use of the deadman/autoshear). The prescribed method in the proposed rule may not be the safest method to undertake. Changing over to a timing circuit for DM/AS systems that would be failsafe type would require engineering and lead times of new equipment to be manufactured, installed and tested. If this is the intent, it cannot be accomplished within 90 days of publication of the final rule. Three years would be appropriate.	When operating with a subsea BOP system, you must: (6) Provide autoshear, and deadman for moored and dynamically positioned; Additional requirements: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) The Deadman Autoshear system must be capable of shearing the body of the drill pipe in use and then sealing the well.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(7)	730.734(a)(7) When operating with a subsea BOP system, you must: (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions; Additional requirements: If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.	There could be unintended consequences. If a failure of the acoustic system results in a mandatory stack pull for repairs, then industry will be encouraged to remove the acoustic system. As per proposed section 250.738(o) acoustic systems will be treated as a redundant system as described in the text.	When operating with a subsea BOP system, you must: (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions or risk assess continuation without the acoustic system; Additional requirements: If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.
§250.734(a)(8)	When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.		When operating with a subsea BOP system, you must: (8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions; Additional requirements: Incorporate two-handed operation for all critical functions.
§250.734(a)(9)	When operating with a subsea BOP system, you must: (9) Clearly label all control panels for the subsea BOP system; Additional requirements: Label other BOP control panels such as hydraulic control panel.		Accept proposed text
§250.734(a)(10)	When operating with a subsea BOP system, you must: (10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system; Additional requirements: The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.		Accept proposed text
§250.734(a)(11)	When operating with a subsea BOP system, you must: (11) Establish minimum requirements for personnel authorized to operate critical BOP equipment; Additional requirements: Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subpart O; and (ii) A comprehensive knowledge of BOP hardware and control systems.	It is not clear if this is intended to impose requirements over and above those of the existing requirements of Subparts O and S. Clarification from BSEE is needed. If additional requirements are being imposed, implementation within 90-days of promulgation of the final rule is not feasible	

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(12)	When operating with a subsea BOP system, you must: (12) Before removing the marine riser, displace the fluid in the riser with seawater; Additional requirements: You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).		When operating with a subsea BOP system, you must: (12) Before planned removal of marine riser, excluding EDS, displace the fluid in the riser with seawater; Additional requirements: You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
§250.734(a)(13)	When operating with a subsea BOP system, you must: (13) Install the BOP stack in a well cellar when in an ice-scour area; Additional requirements: Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.	Change to read "lower BOP stack"	When operating with a subsea BOP system, you must: (13) Install the lower BOP stack in a well cellar when in an ice-scour area; Additional requirements: Your well cellar must be deep enough to ensure that the top of the lower BOP stack is below the deepest probable ice-scour depth.
§250.734(a)(14)	When operating with a subsea BOP system, you must(14) Install at least two side outlets for a chock line and two side outlets for a kill line; Additional requirements: (i) If your stack does not have side oultets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both direction sand must be remote-controlled. (iv) You must install a side outlet below each sealing shear ram . You may have a pipe ram or rams between the shearing ram and side outlet.	changed layout of paragraph Correct "chock line" and "direct sand"	When operating with a subsea BOP system, you must (14) Install at least two side outlets for a choke line and two side outlets for a kill line; Additional requirements: (i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below each sealing shear ram . You may have a pipe ram or rams between the shearing ram and side outlet.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(a)(15)	250.734(a)(15) When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves for annular preventer; Additional requirements: (i) The valves must hold pressure from both directions; (ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular.	Many existing annular BOPs do not have a side outlet. Every valve and every outlet we add to the BOPS increases leak paths and reliability concerns. You must have the capability to circulate below each annular. This rule encourages removal of well control equipment from the BOP stack resulting in an unintentional consequence of removal of lower BOP and installation of a drilling spool Some BOP stacks, the lower annual is integral to the stack frame and would not permit installation of gas bleed valve or line without extensive modification to the vessel or stack.	When operating with a subsea BOP system, you must: (15) Install a gas bleed line with two valves under the annular preventer; Additional requirements: (i) The valves must hold pressure from both directions; (ii) If you have two annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, and your BOP stack was manufactured after the effective date of this regulation, you must have the capability to circulate below each annular.
§250.734(a)(16)	250.734(a)(16) When operating with a subsea BOP system, you must: (16) Use a BOP system that has the following mechanisms and capabilities: Additional requirements: (i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of change of the subsea electronic module batteries in the BOP control pods.		When operating with a subsea BOP system, you must: (16) Use a BOP system that has the following mechanisms and capabilities: Additional requirements: (i) A mechanism coupled with each shear ram to position the entire drill pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule; (ii) The ability to accept the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of change of the subsea electronic module batteries in the BOP control pods.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.734(b)	(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised permit with a verification report from a BSEE-approved verification organization documenting the repairs and that the BOP is fit for service; (2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including deadman and ROV intervention; and (3) Receive approval from the District Manager.	When only the LMRP is retrieved, it is not necessary to re-test deadman or lower stack ROV intervention functions. Broad definition of "BOP system" and undefined "suspension of operations" needs to be clarified in order to limit adverse impact. Present wording leads to unnecessary deadman tests. Conflicts with API 53. Only the affected components are required to be tested.	(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must: (1) Submit a revised permit with a verification report from an independent third party documenting the repairs and that the BOP is fit for service; (2) Perform a new BOP test in accordance with §§ 250.737 and 250.738 upon relatch including any functions affected during the repair; and (3) Receive approval from the District Manager.
§250.734(c)	(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.		Accept proposed text
§250.735	All BOP systems must include the following associated systems and related equipment:		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.735(a)	(a) A surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;	Industry SMEs including OEM, Operator, Contractor, 3rd parties and BSEE collaborated to produce API 53 design and sizing requirements. The industry has reviewed and revised these calculations to reflect how gasses behave at these temperatures and pressures. The BSEE proposed requirement contradicts the requirements of API 53, is not achievable, and is sufficiently ambiguous that industry SMEs cannot achieve a common understanding of the intent. It is not just the direct impact of the additional number of accumulator bottles, but the associated changes to pumping systems and storage tanks. For example, some SMEs concluded that the proposed requirement to provide 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP could result in the elimination of some BOP components from the system. Industry data reflecting rigs in service (see attached) demonstrate the magnitude of the changes to BOP and associated equipment which would be required to achieve compliance with the BSEE proposed rule. This additional equipment would be accompanied by additional maintenance burdens and potentially render the systems less reliable. Equipment owners have been asked to submit details of the cost impacts for their individual rigs, recognizing that such information is commercially sensitive and will rely on BSEE's statement that they will protect such information from disclosure. For certain older rigs, the additional requirements could force the removal of the rigs from service in the US or effectively prevent the entry of these rigs into the US market. (upgrade not feasible?) Industry consensus is that the punitive requirements do nothing to enhance safety or increase reliability.	Delete this paragraph. Sections 6.5.6.2 and 7.6.8.2 of API 53 adequately address these concerns. API 53 is incorporated by reference

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.735(b)	(b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;		(b) A minimum of two pump systems are required; a pump system may consist of one or more pumps. Each pump system shall have an independent power source. These pump systems shall be connected such that the loss of any one power source does not impair the operation of the other pump systems. At least one pump system shall be available and operational at all times system.
§250.735(c)	(c) At least two full BOP control stations. One station must be on the rig floor. You must locate the other station in a readily accessible location away from the rig floor;		Accept proposed text
§250.735(d)	(d) The choke line(s) installed above the bottom well-control ram;		Accept proposed text
§250.735(e)	(e) The kill line that may be installed below the bottom ram, but it must be installed beneath at least one pipe ram;	.	(e) The lowermost line connected to the BOP stack shall be identified as the kill line. For BOPs that have lines installed on each side of the outlet below the lowermost well control ram, either may be designated as a choke or kill line.
§250.735(f)	(f) A fill-up line above the uppermost BOP;		(f) A fill-up line usually connected to the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the hole, at atmospheric pressure.
§250.735(g)	(g) Hydraulically operated locking devices installed on the sealing ram-type BOPs; and	Differentiate between surface and subsea BOPs. Refer back to API 53 in order to minimized effect for surface stacks.	(g) All sealing ram-type preventers shall be equipped with locking devices. Surface stacks can be equipped with manual locks and subsea stacks should be equipped with hydraulic locks.
§250.735(h)	(h) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure.		Accept proposed text
§250.736(a)	(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well-control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.		Accept proposed text
§250.736(b)	(b) Choke manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.		(b) Choke manifold components upstream of the first valve behind the chokes must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. Components downstream of the first valve behind the chokes must have a rated working pressure at least as great as the rated working pressure of the annular BOP. You must install isolation valves on any bleed lines.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.736(c)	(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a rated working pressure at least as great as the rated working pressure of the ram BOPs.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.736(d)	(d) You must use the following BOP equipment with a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations: (1) A kelly valve installed below the swivel (upper kelly valve); (2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack; (3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly; (4) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve installed below the remote-controlled valve; (5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe; (6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe; (7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole; (8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and (9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.	Issue is "rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations" (d) Interpretation of this requirement leads one to believe that a kelly and associated kelly equipment is required. Kelly's are seldom used in OCS jurisdiction and has limited applications. (3) This is not a gap in any industry documents. This methodology is obsolete and has been addressed with MMS in the past. This practice was discontinued in the 80's after the proven use and operation of top drives. This requirement is not a best practice. (4) More specific than API 53 and API 53 should be referenced as this proposed language is not well presented. (5), (6), (7), & (8) In compliance with SC16 documents.	(d) If you use the following BOP equipment it must have a rated working pressure and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations: (1) A kelly valve installed below the swivel (upper kelly valve); (2) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack; (3) If you operate with a mud motor and use drill pipe instead of a kelly, one kelly valve installed above, and one strippable kelly valve installed below, the joint of pipe used in place of a kelly; (4) On a top-drive system equipped with two ball valves, the upper valve is air or hydraulically operated and controlled at the driller's console and the lower valve is a standard ball valve (sometimes referred to as a safety valve) and is manually operated, usually by means of a large hexagonal wrench. If necessary, to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the two top drive valves. However, flow up the pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions: (a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve; (b) most top drive valves cannot be stripped into 7-5/8" or smaller casing; (c) once the top drive's manual valve is disconnected from the top drive, another valve and crossover may be required. (5) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the pipe; (6) A drill string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the pipe; (7) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole; (8) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (i.e., kelly-type valve in a top-drive system) that are essentially full opening; and (9) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737	Your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill string safety valve) must meet the following testing requirements:		Accept proposed text
§250.737(a)(1-2)	(a) Pressure test frequency. You must pressure test your BOP system: (1) When installed; (2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind-shear rams) following the conclusion of the previous test;	(2) For surface systems, a gap has been noted and is being addressed in API 53 - 5th addition or addendum. To look more like the subsea section of the document (Blind shear rams only). Adjusting language to recognize a 21 day BOP test interval (alignment with S 53).	(a) Pressure test frequency. You must pressure test your BOP system: (1) When installed; (2) Before 21 days have elapsed since your last BOP pressure test, or 30 days since your last blind-shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 21st day (or 30th day for your blind-shear rams) following the conclusion of the previous test;
§250.737(a)(3)	(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;		(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 21 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;
§250.737(a)(4)	(4) The District Manager may require more frequent testing if conditions or your BOP performance warrants.		Accept proposed text
§250.737(b)	(b) Pressure test procedures. When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component. You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph outlines your pressure test requirements.		Accept proposed text. Adjust table if needed to recognize a 21 day test interval.
§250.737(b)(1)	You must conduct a…: (1) Low-pressure test… According to the following procedures…: All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(b)(2)	You must conduct a…: (2) High-pressure test for blind-shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components. **According to the following procedures…:** The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.	Testing to pressure lesser of MASP but NTE rated working pressure of the equipment. Recommend that the proposed WCR follow the same references as API53, w.r.t. MASP and MAWHP and how they are applicable relative to operations. This WCR does not split between initial and subsequent testing. For subsea there is stump, initial and subsequent that all have different test pressures. Potential for Unintended Consequences and failure to comply between this requirement and SC16 documents	You must conduct a…: (2) High-pressure test for blind-shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components. According to the following procedures…: The high-pressure test must equal the lesser of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP/MAWHP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP/MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD.
§250.737(b)(3)	**You must conduct a…:** (3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP. According to the following procedures…: The high pressure test must equal 70 percent of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.	This is confusing when trying to mix surface and subsea into one single requirement. Reference API 53 in its entirety. The ability to define these testing requirements in the APD would seem suitable.	You must conduct a…: (2) High-pressure test for blind-shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components. According to the following procedures…: The high-pressure test must equal the lesser of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP/MAWHP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP/MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD
§250.737(c)	(c) Duration of pressure test. Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).		(c) Duration of pressure test. Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. This requirement is to be met within twelve months of publication of the final rule.
§250.737(d)	(d) Additional test requirements. You must meet the following additional BOP testing requirements:		

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Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(1)	You must…: (1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198). Additional requirements…If there is a conflict between API Standard 53 testing requirements and this section, you must follow the requirements of this section.	Recommend using industry standards (API 53) rather than specifying additional requirements.	You must: 1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).
§250.737(d)(2)	**You must…:** (2) Use water to test a surface BOP system. **Additional requirements…** (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.	Experience shows that use of water may not be an appropriate safe practice. Suggest alternative language to select test fluid appropriate for the well conditions. Addressed in API 53 Only the initial or stump test required the use of water. After that point, the use of mud is acceptable. A loss of hydrostatic could result in a well control incident. (See PSA alerts). Clarifications are being addressed in API 53 5th edition. WCR does not break down the water testing requirements as API 53 will.	**You must…:** (2) Use water to test a surface BOP system. **Additional requirements…** (i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests.
§250.737(d)(3)(i-v)	**You must…:** (3) Stump test a subsea BOP system before installation. **Additional requirements…**(i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow (b) and (c) of this section.		**You must…:** (3) Carry out a pre-deployment test of your subsea BOP system before installation. **Additional requirements…**(i) You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must test and verify closure of the following critical ROV intervention functions: (1) shear ram close, (2) one pipe ram close, and (3) LMRP unlock/unlatch intervention functions on your subsea BOP stack during the stump test. (iv) You must follow (b) and (c) of this section.
§250.737(d)(4)(i-iv)	You must…: (4) Perform an initial subsea BOP test. Additional requirements… (i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing.	(i) Conflicts with API 53. There is not a timing requirement between stump testing and installation. This is a risk based operation and is determined by the operator and equipment owner.	You must… (4) Perform a pre-deployment test before running the subsea stack (i) Perform an initial subsea BOP test upon landing on the wellhead. (ii) You must perform the subsequent subsea tests at intervals of no more than 21 days from the initial subsea test. (iii) You must submit test procedures with your APD or APM for District Manager approval. (iv) You must pressure test well-control rams according to (b) and (c) of this section.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(4)(v)	(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must pressure test the selected rams according to (b) and (c) of this section.	Conflicts with API 53, specifies blind shear ram or pipe rams to be functioned by ROV but, not pressure tested and only annually. No plans to change API 53 language.	(v) You must test and verify closure of at least a blind shear ram or a pipe ram annually through a ROV hot stab. The selected ram should close in 45 seconds or less (minimum time to secure the wellbore, does not include functions after the well has been secured).
§250.737(d)(5)	You must…: (5) Alternate tests between control stations and pods. Additional requirements…(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly, (B) The control station used for the pressure test must be alternated between pressure tests, and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests. (ii) Any additional control stations must be function tested every 14 days.	(B) API 53 permits the pressure test to be recognized as a function test. (C) Conflicts with API 53. Cannot achieve this when implementing A & B above. Interpretation is that both pods from both stations is being the requirement. Industry does not accept this proposal. (ii) Conflicts with API 53. Example: If a remote station is only provided with an EDS function then this becomes an endangerment to personnel and the environment.	You must…: (5) function test all well control components, excluding hydraulic connectors and shear rams, to verify the component's intended operation at least once every seven days or as operations allow. Pressure tests qualify as function tests. Casing and blind shear rams shall be function tested at least once every twenty-one days. (A) Designate a primary and secondary station. Prior to deployment, all control stations and both pods shall be function tested. The operability of individual control stations shall be confirmed. Subsequent function tests shall be performed from one BOP control station and one pod weekly. These tests shall rotate through both pods and the two designated control panels. So that one pod and one panel are tested every week but that the same combinations are not tested in consecutive weeks.
§250.737(d)(6)	You must…: (6) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	This is in conflict with API 53 in that both sizes are required for testing whereas, API 53 only requires the smaller pipe on subsequent testing and both sizes on stump testing.	You must…: (6) During pre-deployment (stump) testing, pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools; during subsequent testing, pressure test variable bore-pipe ram BOPs against the smallest size drill pipe in use, excluding drill collars and bottom-hole tools
§250.737(d)(7)	You must…: (7) Pressure test annular type BOPs against the smallest pipe in use.	Somewhat in compliance with API 53. However, for stump testing both sizes are required testing.	You must…: (7) For pre-deployment BOP test (stump test) the annular type BOPs shall be pressure tested against the largest and smallest drill pipe in use. For all subsea pressure tests, the annular BOPs shall be tested against the smallest OD drill pipe to be used in the hole section.
§250.737(d)(8)	You must…: (8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(9)	You must…: (9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	Complies with API 53, surface and subsea.	You must…: (9) Function test annular and pipe/variable bore ram BOPs every 7 days or as operations allow. Pressure tests qualify as function tests.
§250.737(d)(10)	You must…: (10) Function test blind-shear ram BOPs every 14 days.	API 53 requires BSR & CSR function testing every 21 days. WCR require function testing the BSR every 14 days. (Both are at the pressure testing interval however, WCR only addresses the BSR and not the CSR.	You must…: (10) Function test blind-shear ram BOPs not to exceed every 21 days.
§250.737(d)(11)	You must…: (11) Actuate safety valves assembled with proper casing connections before running casing.		Accept proposed text
§250.737(d)(12)	You must…: (12) Test and verify closure capability of all ROV intervention functions on your subsea BOP. Additional requirements… (i) Each ROV must be fully compatible with the BOP stack ROV intervention panels. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.	(12) This is a repeat requirement and may add to some confusion on its intent. (See above) (i) The issue is the stabs and receptacle interfaces but not specifically toward the ROV being FULLY COMPATIBLE. Confusing requirement. Conflicts with API 53.	You must…: (12) test and verify closure of the following critical ROV intervention functions: (1) shear ram close, (2) one pipe ram close, and (3) ram locks and (4)LMRP unlock/unlatch intervention functions on your subsea BOP stack during the pre-deployment (stump) test. Additional requirements… (i) ROV tooling must be compatible with the BOP stack ROV intervention receptacles. (ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval. (iii) You must document all your test results and make them available to BSEE upon request.
§250.737(d)(13)	You must…: (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.		You must…: (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system during commissioning or within 5 years of previous test.
§250.737(d)(13) (i)	Additional requirements… (i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.		Accept proposed text
§250.737(d)(13) (ii)	(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.737(d)(13)(iii)	(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.		(iii) When you conduct the initial deadman system test during commissioning or within 5 years of the previous test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.
§250.737(d)(13)(iv)	(iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.		Accept proposed text
§250.737(d)(13)(v)	(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.	Conflicts w/ API 53, does not require a DMAS test on initial landing but does require a drawdown test specific to the DMAS system accumulators.	(v) For the function test of the deadman system during commissioning or within 5 years of the previous test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.
§250.737(d)(13)(vi)	(vi) You must pressure test the blind-shear ram(s) according to (b) and (c) of this section.	.	
§250.737(d)(13)(vii)	(vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram.		
§250.737(d)(13)(viii)	(viii) You must document all your test results and make them available to BSEE upon request.		Accept proposed text
§250.737(e)	(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the BSEE District Manager at least 72 hours in advance, to ensure that a representative of BSEE will have access to the location to witness any testing.		Accept proposed text
§250.738	The table in this section describes actions that you must take when certain situations occur with BOP systems.		
§250.738(a)	If you encounter the following situation: (a) BOP equipment does not hold the required pressure during a test; Then you must . . . Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, to the District Manager and on the daily report as required in § 250.746.	All issues encountered while pressure testing, which can be corrected, are noted in the pressure testing report. Any issues that cannot be rectified, but do not impair safe operation (BOP stack still meets industry standards and federal regulations), will be sent to the District office with a statement-of-fact.	If you encounter the following situation: (a) BOP equipment does not hold the required pressure during a test; Then you must . . . Correct the problem and retest the affected equipment. You must report any unrepairable problems or irregularities, including any leaks, to the District office and on the daily report as required in § 250.746.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(b)(1-3)	250.738(b) If you encounter the following situation: (b) Need to repair, replace, or reconfigure a surface or subsea BOP system; Then you must . . . (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE-approved verification organization to the District Manager certifying that the BOP is fit for service.	Change term "BOP system" to "BOP stack"	If you encounter the following situation: (b) Need to repair, replace, or reconfigure a surface or subsea BOP stack; Then you must . . . (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report to the District Manager certifying that the BOP is fit for service.
§250.738(c)	If you encounter the following situation: (c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe; **Then you must . . .**Record the reason for postponing the test in the daily report and conduct the required BOP test on the first trip out of the hole.		Accept proposed text
§250.738(d)	If you encounter the following situation: (d) BOP control station or pod that does not function properly; Then you must . . .Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.		Accept proposed text
§250.738(e)	If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.	We do not see the need for a redundant ram on the smaller size pipe providing this pipe is not across the bop stack while drilling. The annular provides a redundant means to seal against the smaller pipe.	If you encounter the following situation: (e) Plan to operate with a tapered string; Then you must . . . Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and two sets of pipe rams must be capable of sealing around the smaller size pipe in the event that this pipe is across the BOP stack when drilling, and excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(f)	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets before running casing to the rated working pressure or MASP plus 500 psi. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.	Conflicts with API 53. a) Implies that casing has to be sheared (not just drillpipe as previously stated); b) nowhere in the WCR and API 53 is there a requirement to shear casing previously mentioned in either document.	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must... Test the ram bonnets seals before running casing to the rated working pressure or MASP/MAWHP plus 500 psi. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
§250.738(g)	If you encounter the following situation: (g) Plan to use an annular BOP with a rated working pressure less than the anticipated surface pressure; Then you must . . .Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Manager.		Accept proposed text
§250.738(h)	If you encounter the following situation: (h) Plan to use a subsea BOP system in an ice-scour area; Then you must . . .Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.		Accept proposed text
§250.738(i)	If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.		If you encounter the following situation: (i) You activate any shear ram and pipe or casing is sheared; Then you must . . . Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report certifying that the BOP is fit to return to service.
§250.738(j)	If you encounter the following situation: (j) Need to remove the BOP stack; Then you must . . .Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.		
§250.738(k)	If you encounter the following situation: (k) In the event of a deadman or autoshear activation, if there is a possibility of the blind-shear ram opening immediately upon re-establishing power to the BOP stack; Then you must . . .Place the blind-shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.	Language is too prescriptive. Field procedures should address the system.	If you encounter the following situation: (k) In the event of a deadman or autoshear activation, if there is a possibility of the blind-shear ram opening immediately upon re-establishing power to the BOP stack; Then you must address that possibility prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.

ATTACHMENT A

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(l)	250.738(l) If you encounter the following situation: (l) If a test ram is to be used; Then you must . . .Conduct the initial BOP test after latching up using a test tool, and test the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated BOP components must also be functioned during the well connection test.	Exclude hydraulic connectors, wet-mate connectors, and all stabs.	If you encounter the following situation: (l) If a test ram is to be used; Then you must . . .Conduct the initial BOP test after latching up using a test tool, and test the wellhead/BOP connection to the maximum pressure for the approved ram test for the well. All hydraulically operated well control BOP components must also be functioned during the well connection test.
§250.738(m)	If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . .Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BSEE-approved verification organization on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.		If you encounter the following situation: (m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Then you must . . .Contact the District Manager and request approval in your APD or APM. Your request must include a report on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
§250.738(n)	If you encounter the following situation: (n) You have pipe/variable bore rams that have no current utility or well-control purposes; Then you must . . .Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.738(o)	If you encounter the following situation: (o) You install redundant components for well-control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Then you must . . .Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE-approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.		If you encounter the following situation: (o) You install redundant components for well-control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Then you must . . .Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.
§250.738(p)	If you encounter the following situation: (p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Then you must . . .Ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.	Removed 30 minute stable time period (this time needs to be determined by the operator and based upon offset well data) and removed "immediate" removal as it is not possible to "Immediately" do anything. Actions should be taken as quickly as they can be done while honoring personnel safety risks.	If you encounter the following situation: (p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations. Then you must . . .Ensure that the well has been stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP/MAWHP conditions are reached as defined for the operation.
§250.739(a)	(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in § 250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of all critical components beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.	Need to clarify the term "critical components." The statement 'Engineering practices and industry standards' is too vague and open to inconsistent interpretation. Preventative and remedial maintenance is critical to maintaining a satisfactory level of reliability during the operational life of critical equipment. Risk/condition based maintenance could be improved if we reduced the amount of testing we do as this activity is the most common use, and therefore wear, of the equipment; we know that we are as good as our last test but we want to be confident for our next one.	(a)You must maintain and inspect your BOP system, as defined in API 53 1.1.2 (incorporated by reference in § 250.198), to ensure that the equipment functions as designed. All BOP maintenance and inspections must meet the equipment owner's PM program. You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the required traceability of the equipment and record the results of your inspections and maintenance actions. You must make all records available to BSEE upon request.

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.739(b)	(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE-approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.	The prohibition of phased inspections would put rigs out of service for estimated 6 months minimum. A complete disassembly of a BOP stack introduces major safety risks as well as infant mortality of equipment into system. A requirement to follow this would put our current strategies multiple steps backwards. It is not in line with API 53 (or any other industry standard). There are safety issues with the multiple very heavy lifts in congested areas. Technology exists that allows for detailed inspection without disassembly. There is insufficient data to support any benefits of this approach. There is insufficient infrastructure in the industry to manage this requirement. Continuous survey is a proven method for this and other industries. A single inspection does not make the system any safer. This could affect international rigs coming into the jurisdiction or existing equipment. How does this affect existing equipment? We believe that third party presence is not always required due to the proposed competency requirements that require the subsea teams to be qualified to meet OEM standards. We believe that review of our reports would be sufficient. Any failures or issues discovered during the inspection are reported as part of the Equipment Failure Data Reporting. This will be detrimental to all operators.	(b) At least every five (5) years, the well control system components shall be inspected for repair or remanufacturing in accordance with the equipment owner's PM program and manufacturer's guidelines. Individual components may be inspected on a staggered schedule. As an alternative to a schedule-based inspection program, a rig-specific inspection frequency can vary from this 5 year interval if the equipment owner collects and analyzes condition based data (including performance data) to justify a different frequency. This alternative may include dynamic vs. static seals, corrosion resistant alloy inlays in sealing surfaces, resilient vs. metal to metal seals, replaceable wear plates, etc. For schedule and condition based inspection programs, certain equipment shall undergo a critical inspection (internal/external visual, dimensional, NDE, etc.) annually, or upon recovery if exceeding 1 year: e.g. shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft button/foot, welded hubs, ram cavities and ram blocks. The actual dimensions shall be verified against the manufacturer's allowable tolerances. Inspections shall be performed by a competent person(s). Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections. Documentation of all repairs and remanufacturing shall be maintained in accordance with API 53 7.6.10. These inspections shall be documented and made available to BSEE District Manager upon request.
§250.739(c)	(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.739(d)	(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices.	OEMs do not provide training requirements. Training and competency requirements addressed thru SEMS. Recognized engineering practices are addressed thru the applicable API standards and specifications.	(d)Require that the personnel, who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the equipment owner and that such maintenance, inspection, and repair be undertaken in accordance with API 53.
§250.739(e)	(e) You must make all records available to BSEE upon request. You must ensure that the rig owner maintains your BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. You must maintain all design, maintenance, inspection, and repair records at an onshore location for the service life of the equipment.	The equipment design data is proprietary to the OEM and therefore the design cannot be maintained by anybody other than the product design owner.	(e) You must make all records available to BSEE upon request. You must ensure that the equipment owner maintains the BOP maintenance, inspection, and repair records on the rig for 2 years from the date the records are created or for a longer period if directed by BSEE. The equipment owner must maintain all maintenance, inspection, and repair records at an onshore location for the service life of the equipment.
§250.740	You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in § 250.741 at a location of your choice, except as required in § 250.746. The records must contain complete information on all of the following:	Is additional Real Time Monitoring required. Real time Monitoring is not typically done on HWO or other Thru Tree interventions. The cost assessment is unrealistic as the reports are generated by the technical staff in the RTC and not administrative staff. Daily Reports and Event Reports are generated by the technical staff and part of the $40,000 daily cost.	
§250.740 (a)	(a) Well operations, all testing conducted, and any real-time monitoring data;	These measurements and calculations are done on the rig, regardless if real time is present or not Onshore monitor will have to have realtime communications with MODU operations, as Crane activity can make 5+ bbl swings in Active or Trip tank readings. This can result in erroneous assumptions and invalid conclusions, due to lack of situation awareness.	(a) Well operations, all testing conducted, and real-time monitoring data, per your Monitoring Plan; (b) Descriptions of formations penetrated; (c) Content and character of oil, gas, water, and other mineral deposits in each formation; (d) Kind, weight, size, grade, and setting depth of casing; (e) All well logs and surveys run in the wellbore; (f) Any significant malfunction or problem; and (g) All other information required by the District Manager.
§250.740(b)	(b) Descriptions of formations penetrated;		
§250.740(c)	(c) Content and character of oil, gas, water, and other mineral deposits in each formation;		
§250.740(d)	(d) Kind, weight, size, grade, and setting depth of casing;		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.740(e)	(e) All well logs and surveys run in the wellbore;		
§250.740(f)	(f) Any significant malfunction or problem; and	Unclear requirements, covered by 250.740(g)	
§250.740(g)	(g) All other information required by the District Manager.	Additional information required is unknown.	(g) All other information required by the District Manager in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.
§250.741	You must keep records for the time periods shown in the following table.		Accept proposed text
§250.741(a)	You must keep records relating to . . . (a) Drilling; Until . . .90 days after you complete operations.		Accept proposed text
§250.741(b)	You must keep records for the time periods: (b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data; Until … 2 years after the completion of operations.	This is not necessary on a decommisioning operation after the well has been plugged. Data set may needed to be kept for longer durations in the event of a redrill or sidetrack.	
§250.741(c)	You must keep records relating to . . . (c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone. Until . . . You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.		Accept proposed text
§250.742	You must submit to BSEE copies of logs or charts of electrical, radioactive, sonic, and other well logging operations; directional and vertical well surveys; velocity profiles and surveys; and analysis of cores. Each Region will provide specific instructions for submitting well logs and surveys.		
§250.743(a)	(a) For operations in the BSEE GOM OCS Region, you must submit Form BSEE–0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12:00 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE-0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.		Accept proposed text
§250.743(b)	(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE–0133, WAR, to the District Manager on a daily basis.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.743(c)	(c) The WAR must include such information as a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.		Accept proposed text
§250.743(c)	(c) The WAR must include such information as a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.		Accept proposed text

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.744(a)	(a) Within 30 days after completing operations, except routine operations as defined in § 250.601, you must submit Form BSEE–0125, End of Operations Report (EOR), to the District Manager. The EOR must include a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The wells' status date is subject to the following:		Accept proposed text
§250.744(a)(1)	(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and		Accept proposed text
§250.744(a)(2)	(2) For subsea well operations, the operation end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.		Accept proposed text
§250.744(b)	(b) You must submit public information copies of Form BSEE–0125 according to § 250.186(b).		Accept proposed text
§250.745	The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records:		
§250.745(a)	(a) Well records as specified in § 250.740;		
§250.745(b)	(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;		
§250.745(c)	(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or		
§250.745(d)	(d) Other reports and records of operations.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§250.746	You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in § 250.740. In addition, you must:	If you encounter the following situation: (a)BOP equipment does not hold the required pressure during a test; Then you must....Correct the problem and retest the affected equipment. You must report any unrepairable problems or irregularities, including any leaks, to the District office and on the daily report as required in 250.746	
§250.746(a)	(a) Record test pressures on pressure charts;		
§250.746(b)	(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts and daily reports as correct;		
§250.746(c)	(c) Document on the daily report the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;		
§250.746(d)	(d) Identify on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);		
§250.746(e)	(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue; and	Suspending operations may not be safe; we need to be able to handle minor issues internally.	
§250.746(f)	(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the facility for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the facility. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all records available to BSEE upon request.		
§250.1612	Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 of this part or as approved by the District Manager.		

Proposed Regulation Reference	Proposed New Regulation Text	Comments	Recommended Industry Text
§ 250.1703(b)	(b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);	Need to clarify the reference to 11D1.	(b) Permanently plug all wells. After the implementation date of this regulation, all permanently installed (as defined in the APD and/or APM) packers and bridge plugs installed during decommissioning must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);
§250.1703(e)	(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;		Accept proposed text
§250.1703(f)	(f) Follow all applicable requirements of Subpart G;		Accept proposed text
§250.1704(g)(1) (i-ii)	Decommissioning applications and reports: (g) Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125; When to submit: (1) Before you temporarily abandon or permanently plug a well or zone, Instructions: (i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.		Accept proposed text
§250.1704(g)(2)	When to submit: (2) Before you install a subsea protective device, Instructions: Refer to § 250.1722(a).		Accept proposed text
§250.1704(g)(3)	When to submit: (3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device, Instructions: Refer to § 250.1723.		Accept proposed text
§250.1704(h)(1)	(h) Form BSEE-0125, End of Operations Report (EOR); When to submit: (1) Within 30 days after you complete a protective device trawl test, Instructions: Include information required under § 250.1722(d).		Accept proposed text
§250.1704(h)(2)	When to submit: (2) Within 30 days after you complete site clearance verification activities, Instructions: Include information required under § 250.1743(a).		Accept proposed text
§250.1715(a)(3) (iii)(B)	(B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;		

Attachment B

BSEE Proposed Well Control Rule Cost and Economic Analysis

July 2015

Prepared for:

American Petroleum Institute (API)

Prepared by:

Quest Offshore
CLARITY • INSIGHT • VISION

BLADE
ENERGY PARTNERS

Executive Summary

Introduction

The U.S. DOI Bureau of Safety and Environmental Enforcement (BSEE) recently published new requirements and procedures related to the proposed rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" (hereafter, proposed rule). Quest Offshore Resources (hereafter, Quest Offshore or Quest) and Blade Energy Partners (hereafter Blade Energy or Blade) undertook a study to evaluate the potential cost and economic impact effects of the proposed rule (and associated sections and subsections) on oil and gas drilling operations in the US Gulf of Mexico (GOM), and the influence that these effects would have on the broader economy. Although the proposed rule would apply to all US offshore oil and natural gas development, only the impacts to the Gulf of Mexico were considered for this study.

This study examines the proposed rule, determines the estimated cost and impact of the rules, and attributes these costs and impacts to a model of project design, economics and timelines to determine the effects these rules could have on overall GOM oil and gas development. Once the impact on GOM activity was projected, estimates of the related spending and employment were calculated to quantify the overall economic impact of the proposed rule.

Cost of the Proposed Rule

Construction of a detailed analysis for each individual section/requirement of the proposed rule was undertaken by Quest Offshore and Blade Energy. The increased costs resulting from the rules adoption are expected to further increase expenses incurred by industry participants throughout the study period. The cost estimates presented in the study exclude many costs already being spent by the industry prior to the publishing of the proposed rule.

The increased costs associated with the proposed rule are likely to be felt throughout the offshore oil and gas supply chain. Certain operators and contractors, however, are likely to be effected more than others. Cumulative direct costs due to the adoption of the proposed rule as currently written are estimated at over $32 billion for the ten years from 2017 to 2026. The expected impact of the proposed rule will be an increase in the total time and cost required to drill many offshore wells, as well as lead to the replacement of blow out preventers (BOP) and other capital equipment. (Table 1)

Table 1: 10 Year Direct Cost Estimates – Base Development Scenario ($Millions[1])

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419	$978	$1,041	$1,052	$11,846
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14	$13	$12	$15	$127
Containment	$113	$114	$179	$181	$190	$99	$97	$98	$85	$86	$1,241
Rig Requirements	$204	$205	$205	$215	$239	$239	$240	$244	$247	$250	$2,288
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56	$63	$63	$50	$670
Tubing and Wellhead Equipment[2]	$33	$1	$1	$1	$1	$1	$1	$1	$1	$1	$38
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551	$1,357	$1,601	$1,830	$15,620
Grand Total	$2,421	$2,800	$3,402	$3,547	$3,589	$3,606	$3,378	$2,753	$3,050	$3,284	$31,831

Source: Quest Offshore Resources, Inc.

Impact of Proposed Rule – Gulf of Mexico Oil and Gas Development

If the proposed rule is implemented as written, it would likely reduce the total amount of Gulf of Mexico oil and natural gas activity, including the number of wells drilled and projects developed. The proposed rule will likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deep water wells which may no longer be drillable, and the resources that these wells might have developed may be lost. A significant number of both shallow and deep water wells drilled into depleted reservoirs may also become undrillable, and those resources would also remain undeveloped. These lost reserves would primarily result from the effects of §250.414, "Planned safe drilling margins", though other new regulations may also have a significant effect on the ability to produce from these reserves. Adoption of the proposed rules is expected to lead to a decrease of an average of around 20 exploration wells drilled per year and around 29 development wells per year. Some of these wells are expected to begin drilling, only to be abandoned prior to completion due to the proposed rule.

This study projects that oil and natural gas production in the Gulf of Mexico will be 2.28 million barrels of oil equivalent (BOE) per day in 2017, and grow to 3.10 million BOE per day by 2030. Under the proposed rule, Gulf of Mexico production is forecasted to be nearly 15% or 0.48 million BOE per day lower by 2030.

Total cumulative spending on offshore oil and natural gas development in the Gulf of Mexico OCS is projected at nearly $550 billion between 2017 and 2030 or roughly $39.2 billion per year. If the proposed rule is adopted, cumulative spending is projected at $493 billion; an average reduction of about $4 billion or over 10 percent per year.

Economic Impact of Proposed Rule

The study projects total employment supported from the Gulf of Mexico offshore oil and natural gas industry to rise from approximately 363 thousand in 2015 to over 466 thousand by 2030 under the base development scenario. The adoption of the proposed rule is expected to lead to a reduction in

[1] All costs, spending, GDP Impacts, and government revenues are calculated in constant 2014 dollars.
[2] Tubing and Wellhead Equipment costs associated with Well Design requirements in the proposed rule are included in Well Design Costs (Ex. increased casing costs due to drilling margin requirements.)

industry supported employment levels by over 50,000 by as early as 2027 due to reduced oil and natural gas development. (Table 2)

Table 2: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030 (Thousands)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409	409	408	412	421	363	400	419	441	449	449
Proposed Rule	409	409	408	412	421	363	400	412	417	423	413
Difference	-	-	-	-	-	-	-	7	24	26	36

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	434	433	430	434	438	461	469	467	460	467
Proposed Rule	398	399	387	388	403	415	418	411	409	414
Difference	36	34	43	46	35	46	51	56	51	53

Source: Quest Offshore Resources, Inc.

The Gulf of Mexico offshore oil and natural gas industry will contribute an estimated $31.35 billion annually to US GDP in 2015, and is projected to grow to over $40 billion by 2030 (Table 3). The proposed rule, if enacted as written, is projected to lead to a reduction of GDP supported Gulf of Mexico oil and natural gas activities of $4 billion annually by 2030. The 10-year cumulative GDP cost burden of the rule from 2017 to 2026 is estimated at $28.5 billion.

Table 3: Estimated GOM Supported GDP by Scenario – 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$36,077	$38,084	$38,862	$38,699
Proposed Rule	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$34,726	$36,937	$37,817	$36,857
Difference	$0	$0	$0	$0	$0	$0	$0	($1,351)	($1,147)	($1,045)	($1,841)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$37,332	$36,991	$36,661	$36,948	$37,330	$39,618	$40,400	$40,297	$39,641	$40,141
Proposed Rule	$35,099	$34,186	$33,523	$33,819	$34,297	$35,281	$35,900	$36,851	$35,682	$36,133
Difference	($2,233)	($2,805)	($3,138)	($3,130)	($3,034)	($4,337)	($4,500)	($3,445)	($3,960)	($4,007)

Source: Quest Offshore Resources, Inc.

Annual government revenues from Gulf of Mexico lease sales, rents, and royalties is expected to rise from about $5 billion in 2015 to $13 billion by 2030 under the base development scenario. Reduced oil and natural gas development anticipated under the proposed rule is projected to lead to lower overall government revenues, primarily as a result of lower production royalties being collected with lower production volumes. Reduced government revenues could be as high as $1 billion per year as early as 2023, and $2 billion by 2028. The 10-year cumulative lost government revenue burden of the rule from 2017 to 2026 is estimated at $10 billion.

Table 4: Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,625	$8,050	$8,262	$8,828
Proposed Rule	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,389	$7,533	$7,746	$8,110
Difference	$0	$0	$0	$0	$0	($0)	($0)	($236)	($517)	($516)	($719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$9,188	$9,518	$9,953	$10,307	$10,909	$11,247	$11,780	$12,222	$12,777	$13,254
Proposed Rule	$8,267	$8,557	$8,740	$8,889	$9,164	$9,580	$9,865	$10,148	$10,488	$10,870
Difference	($921)	($961)	($1,213)	($1,418)	($1,745)	($1,667)	($1,915)	($2,074)	($2,289)	($2,385)

Source: Quest Offshore Resources, Inc.

Adoption of the proposed “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” rule is expected to significantly increase costs for operators, contractors, and other participants in the Gulf of Mexico offshore oil and natural gas industry. This will likely lead to reduced activity and spending, which is projected to lower production, employment levels, and the growth in GDP and government revenues.

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Section 1 - Introduction

In the Gulf of Mexico, the oil and gas industry has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by providing desirable and well-paying employment for hundreds of thousands of Americans, creating revenues for many levels of the U.S. government, and by contributing to the country's energy needs. The industry has grown into the world leader in offshore production, safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in those now-mature fields, and production has been declining.

Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have been renewing the strength of the offshore industry, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the positive economic benefits which it brings. The Gulf has steadily grown into one of the world's most prominent and important oil and natural gas production areas, both in terms of economic value and importance to the global oil and gas industry.

Through an expanded and rigorous set of industry standards put in place over the last five years, the Gulf of Mexico has come to be seen throughout the world as the standard of safety in deepwater and high pressure/high temperature production. Companies operating in the region have not only developed technologies capable of safely and reliably operating in previously impossible-to-reach areas and depths, but have built the region into a center for research and innovation, and a global leader in safety, reliability and technology. As a result of the importance of the industry to the U.S. economy and energy security, any significant changes to regulations should be carefully evaluated.

1.1 Purpose of the Report

Following the announcement of proposed changes to the blowout preventer systems and well control regulations, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", by the Bureau of Safety and Environmental Enforcement (BSEE), Quest Offshore Resources was commissioned by the American Petroleum Institute (API), in collaboration with Blade Energy Partners, to provide an independent evaluation of the potential costs associated with the proposed rule. In addition, potential impacts on Gulf of Mexico oil and natural gas development, supported employment, GDP, and government revenue were also to be projected.

The report seeks to identify the costs associated with additional engineering, regulatory oversight, constrained drilling margins, additional BOP construction and maintenance requirements, changes to the regulations surrounding casings and decommissionings, real time monitoring and well containment regulations, amongst others. Once these costs are established, the report will determine the effect that these additional cost burdens will have on project viability, the broad health of the U.S. oil and gas industry and the US economy as a whole.

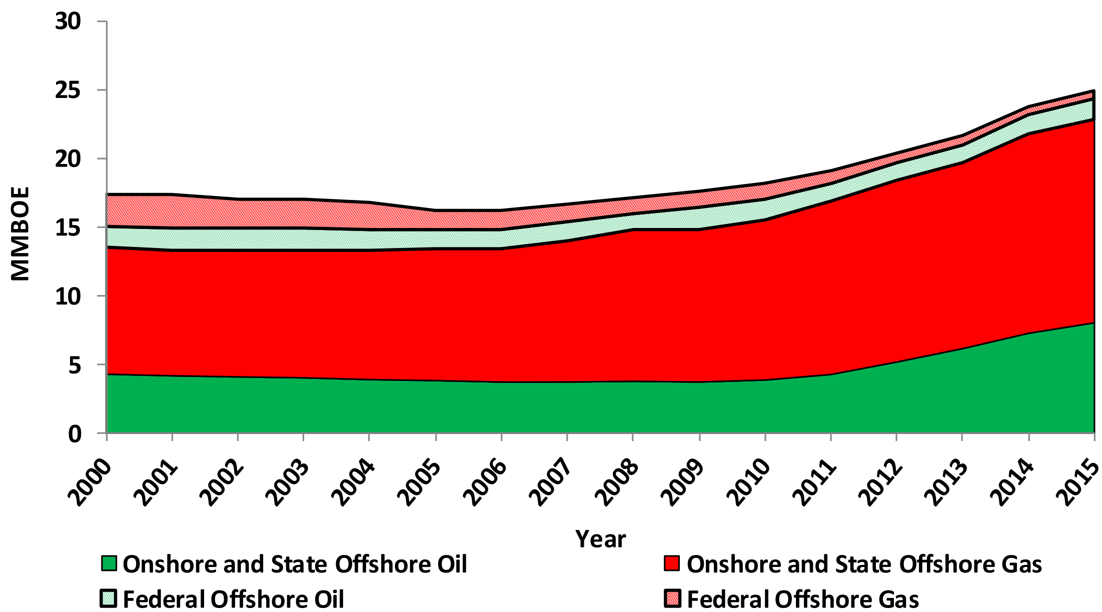
1.2 Report Structure

In this report, Quest will first outline the study methodology in Section 3, followed by a summary of the direct costs associated with the new regulations in Section 4. Following that summary, the study will present forecasts of US offshore oil and gas activity in both the current regulatory environment and under the proposed rule in Section 5. Based on the findings from the activities forecasts, the study them outlines the macroeconomic effects of the proposed regulations on total employment, gross domestic product (GDP) and government revenues in Section 6. Following the findings and conclusions in Section 7, the tables and appendices section contains detailed information on the specific assumptions (Section 8), calculations and findings of the study, as well as a line-by-line analysis of the proposed rule.

1.3 Projected Gulf of Mexico Oil and Natural Gas Development

In recent years, total U.S. oil and natural gas production has increased from approximately 17 million barrels of oil equivalent (MMBOE) in 2006 to over 25 MMBOE in 2015 (Figure 1). This is primarily due to rising production from shale gas and tight oil formations. The dramatic increase in onshore unconventional oil and natural development has been a major contributor in increasing U.S. energy security as well as a significant contributor to the economic recovery in a number of states. U.S. offshore oil and natural gas production, predominately from the Gulf of Mexico, has recently declined. There are, however, a large number of projects under development in the Gulf that are poised to significantly increase output.

Figure 1: U.S. Oil and Natural Gas Production 2000 to 2015



Source: Energy Information Administration

As of April 2015, U.S. domestic crude production has grown to 9.7 MMbbl/d (million barrels of oil per day), distributed through:

- 1.51 MMboe/d from the Gulf of Mexico Federal Outer Continental Shelf

- .046 MMboe/d from offshore California
- .51 MMboe/d from onshore and offshore Federal Alaska
- 7.6 MMboe/d from onshore (including shale) and offshore State waters

Natural gas production nationwide has also grown to 75 BCF/d (billion cubic feet of marketed production per day). It is estimated that the oil and gas industry currently supports 9.8 million jobs nationwide[3].

Under the current regulatory structure, growing production from the U.S. offshore areas driven by the Gulf of Mexico OCS is expected both by this study as well as other sources such as the U.S. Energy Information Administration. While this forecast shows a positive outlook for US oil and gas production and energy security, there is the potential for these regulations to impact overall output, and hinder the US return to energy dominance.

1.4 Excluded From This Study

This paper has been limited in scope to the assessment of the effects of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" on the Gulf of Mexico OCS, though the rule will affect all U.S. OCS offshore oil and natural gas exploration and production areas both current and future. The study also does not attempt to calculate the effects of the proposed rule on mid-stream or down-stream oil and natural gas entities. In addition, the calculated government revenue potential does not include personal income taxes, corporate income taxes or local property taxes.

Given the unpredictable nature of advancements in technology and innovation in the oil and gas industry, the scope of this paper was limited to the effects that new regulations would have on future activity with the assumption that the methods and equipment mentioned in the regulation would still be in use at the end of the study period. It is entirely possible that new designs, methods and target reservoirs would change over time and no longer fall under the umbrella of these regulations, but if that were the case, the effects would be primarily felt toward the end of the forecast period.

In addition to the possibility of new technologies being used in the region, the study has also excluded the effects of activity in other regions inclusive of Alaska, Pacific, and Atlantic OCS regions. It is a very likely possibility that exploration and production activities in the OCS areas will see similar disruptions within the future activity forecast under the proposed regulations.

Overall, given the constraints and assumptions discussed above, it is likely that the costs and economic impacts presented in this study represent a conservative projection of the impact of the proposed rule.

[3] Source PwC – http://www.api.org/~/media/Files/Policy/Jobs/Economic_impacts_Ong_2011.pdf

1.5 About Quest Offshore

Quest Offshore Resources, Inc. is a full-service market research and consulting firm focused on the global offshore oil and natural gas industry. As a function of Quest's core business, the company is engaged daily in the collection and analysis of data as it relates to the offshore oil and natural gas industry. Quest serves the global community of operating oil and natural gas companies, their suppliers, financial firms, and many others by providing detailed data and analysis on capital investment and operational spending undertaken by the offshore industry. Quest collects and develops market data from a variety of sources at the project level for projects throughout the world.

Data is tracked in Quest's proprietary Enhanced Development Database as well as additional proprietary databases related other facets of the global supply chain worldwide. Quest aggregates capital and operating expenditures on a project by project basis for projects worldwide, with detailed information recorded on the supply of the equipment and services necessary to develop individual offshore oil and natural gas projects. Quest Offshore tracks not only existing or historical projects, but also projects that are in all stages of development from the prospect (or undrilled target) stage through to producing and decommissioned projects. For projects without firm development information, Quest utilizes benchmarking based on the proprietary databases mentioned above to forecast development timing and scenarios appropriate to the type of development, the developments' characteristics and region.

1.6 About Blade Energy

Blade Energy Partners is an independent consulting company that focuses on resolving the challenges of complex projects in the energy industry. The company provides leading-edge expertise to solve drilling, completion, production, reservoir and pipeline challenges. Blade works with the sole objective of safely and efficiently maximizing returns on reserves and assets. Since its creation over ten years ago, Blade has collaborated on a wide variety of engineering, research, and development projects in several sectors of the oil and gas and geothermal industries. Blade comprises over 70 engineers, scientists, and project managers. Sixty percent of our staff possess advanced degrees and of those, twenty percent hold doctoral degrees in applied science or engineering. Blade engineers are highly experienced, with, on average, 20+ years in the industry, serving major operating and service companies.

Section 2 - Study Methodology

2.1 Data Development

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the Bureau of Safety and Environmental Enforcement (BSEE), proposed rule on “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control”, as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 with the purpose of providing a summary of the most impactful areas of these regulations. This study in no way is exhaustive, especially in light of the relatively short period available to develop this analysis and the highly technical nature of these regulations.

This analysis focuses on the likely engineering burdens and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible. As such, this analysis is essentially forward looking and potentially subject to significant changes based on the content of the final rule as implemented by BSEE, the way in which it is implemented, and a variety of other factors. However, the report’s authors believe that this approach is the best available way to consider this rule, as a backwards looking review based on previous industry activity would likely overstate the effects of these regulations.

Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual sections of the proposed rule without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this report, as well as the significant uncertainties about the way proposed rule would be implemented if enacted, the projected costs, engineering requirements and operational burdens for all proposed regulations are not included in this report. Additionally, the internal costs to BSEE of implementing and administrating the proposed rule are not calculated in this report.

2.2 Engineering Review

The engineering review of the proposed rule was undertaken by a number of by various subject matter experts within Blade.. The review focused on the likely engineering and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible, while identifying any burdens imposed by the regulation which could not be overcome by additional engineering or operational means. The engineering review attempted to provide the most reasonable outcome and implications of the proposed regulations, while emphasizing the likely effects of the adoption of the regulations as written. Blade provides its independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.3 Limitations of the Report

The report’s authors make no representation as to the effects of proposed regulations not addressed specifically in this report and do not discount the possibility that these proposed changes could impose significant engineering, operational or other burdens on industry or regulators. The report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering, operations and advances in technology are an independent good faith qualitative view arising from considerations by various subject matter experts within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (an engineering consulting company in well design, engineering and operations). Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.4 Cost Calculations

The cost calculations associated with the proposed rule were developed by Quest by calculating the projected engineering and operational burdens by reasonable assumptions of the costs associated with them and the length or scale of these burdens. (ex. $923 for an engineering man day based on the Society of Professional Engineers salary survey and projections of additional employment costs). All costs associated with the regulation were calculated on the most economic method for overcoming the burden imposed by the regulations and any burdens which would overlap with other burdens imposed by the regulations were discounted to avoid double counting. All costs presented in this study are in constant 2014 dollars.

2.5 Scenario Development

The report's scenario development focused on constructing a tiered "bottom-up" model that separates the complete life cycle of offshore operations and subsequent effects into three main categories and five sub categories. The three main categories are as follows; an "Activity" model that assesses potential reserve information in the context of estimating the possible number of projects within the Gulf of Mexico OCS and the currently forecasted projects and trends in exploration and project development in the region; a "Spending" model based on the requirements to develop projects within the "Activity Forecast"; and an "Economic" model focused on the economic impact on employment and government revenue from the "Spending" model. These categories include, leasing activity, drilling, infrastructure & project development, and production & operation.

After the creation of the baseline model, the operational, cost, drilling and development impacts of the report's analysis of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", were applied to the base scenario forecast resulting in the creation of the "Proposed Rule Scenario" which attempts to provide a reasonable projection of oil and natural gas exploration and development activity in the Gulf of Mexico OCS if the proposed rule was enacted as it is currently proposed. After the development of this scenario, the scenario's potential implications for oil and natural gas production, employment, GDP, and government revenues were then calculated.

Section 3 - Summary of Potential Costs

The proposed rule “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” is expected to have significant direct costs to entities developing oil and natural gas resources in the US OCS such as the Gulf of Mexico. In addition to direct costs, the proposed rule is likely to impose additional costs to the US economy due to slower or reduced OCS development. While the increased costs of the rule are likely to be felt by all participants in Gulf of Mexico OCS oil and natural gas exploration activities, the effects are most likely to disproportionately affect certain operators and contractors.

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the proposed rule with the purpose of projecting the total cost of the proposed rule if implemented as currently written. This analysis is in no way is exhaustive, especially in light of the relatively short period available to develop this analysis, and the highly technical nature of these regulations. This analysis focuses on the likely engineering and operational effects of these regulations and wherever possible attempts to calculate the cost of overcoming these burdens.

The following table, prepared by Quest Offshore Resources, presents summary of the estimated direct costs of the proposed rule (Table 5).

Table 5: Estimated 10 Year Costs by Rule by Subsection – 2017 to 2026 ($Millions)

30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.107 (a)	Compliance and Documentation	$65.2	$6.5	1
§ 250.107 (e)	Compliance and Documentation	$61.7	$6.2	2
§ 250.1703 (b)	Well Design	Contributes to Packers and bridge plugs inventory loss	See line 86	3
§ 250.1703 (f)	Well Design	Not currently calculated[4]		4
§ 250.413 (g)	Well Design	$6.9	$0.69	5
§ 250.414 (c)	Well Design	$10,689	$1,069	6
§ 250.414 (j)	Well Design	$6.9	$0.69	7
§ 250.414 (k)	Well Design	$1,126	$113	8
§ 250.415 (a)	Well Design	$26	$2.6	9
§ 250.418 (g)	Well Design	$3.5	$0.346	10
§ 250.420 (a)(6)	Well Design	$1,126	$113	11
§ 250.420 (b)(4)	Well Design	$1.7	$0.173	12
§ 250.420 (c)(2)	Well Design	$983	$98	13
§ 250.421 (b)	Well Design	$441	$44	14
§ 250.427 (b)	Well Design	Large dead weight loss of wells / projects from forecast	See line 6	15
§ 250.428 (b)	Well Design	$195	$19.5	16
§ 250.428 (c)	Well Design	Not currently calculated		17
§ 250.428 (k)	Well Design	$1.7	$0.173	18
§ 250.462	Containment	$1,240	$124	19
§ 250.462 (b)	Containment	Contributes to containment	See line 19	20
§ 250.462 (c)	Containment	$1.1	$0.11	21
§ 250.462 (d)	Well Design	$195	$19.5	22
§ 250.462 (e)	Containment	Contributes to containment	See line 19	23
§ 250.518 (New e)	Tubing and wellhead equipment	Contributes to Packers and bridge plugs inventory loss	See line 86	24
§ 250.518 (e)(2)	Tubing and wellhead equipment	$1.1	$0.113	25
§ 250.518 (e)(4)	Tubing and wellhead equipment	$1.7	$0.173	26
§ 250.518 (New f)	Tubing and wellhead equipment	$1.7	$0.173	27
§ 250.619 (f)	Tubing and wellhead equipment	$1.7	$0.173	28
§ 250.710	Rig Requirements	$2,288	$229	29
§ 250.712	Rig Requirements	Not currently calculated		30
§ 250.712 (a)	Rig Requirements	Not currently calculated		31
§ 250.712 (e)	Rig Requirements	Not currently calculated		32
§ 250.712 (f)	Rig Requirements	Not currently calculated		33
§ 250.720	Well Design	Not currently calculated		34
§ 250.721 (a)	Well Design	Not currently calculated		35
§ 250.721 (e)	Well Design	$327	$33	36
§ 250.721 (f)	Well Design	$12.2	$1.2	37
§ 250.721 (g)	Well Design	$478	$48	38
§ 250.722	Well Design	$0.346	$0.03	39
§ 250.723	Well Design	Not currently calculated		40
§ 250.724	RTM	$670	$67	41
§ 250.730	BOP	Contributes to BOP replacement	See line 85	42
§ 250.730 (a)(3)	BOP	Not currently calculated		43
§ 250.730 (a)(4)	BOP	Not currently calculated		44

[4] Sections of the proposed rule marked as not currently calculated denote sections with some expected cost and/or operational burden that was unable to be calculated due to the time limitations associated with this study.

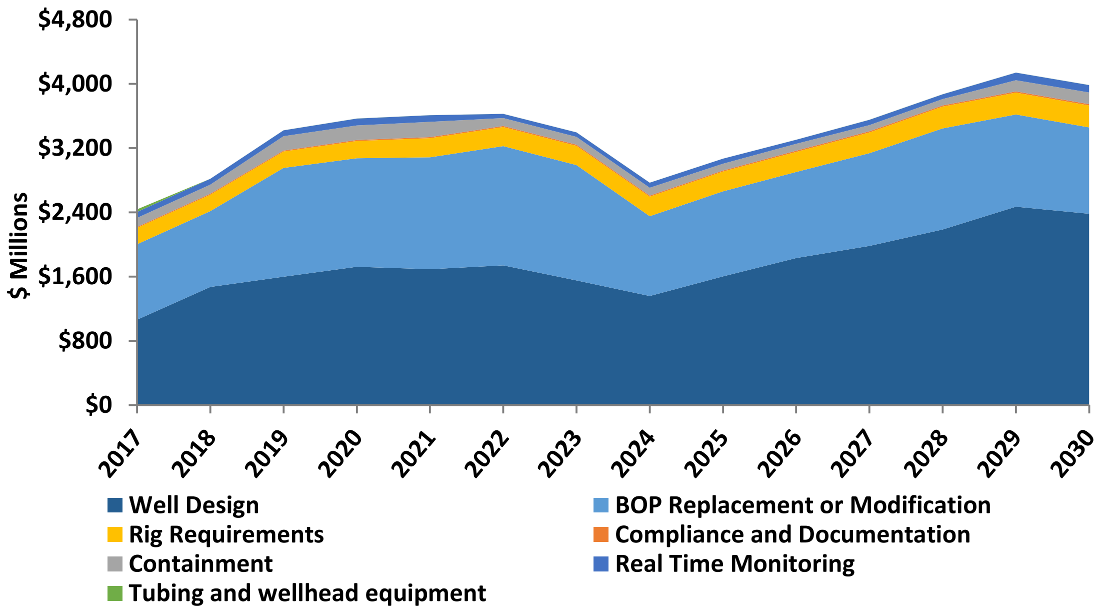
30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.730 (d)	BOP	Contributes to BOP replacement	See line 85	45
§ 250.731 (a & b)	BOP	$3.3	$0.33	46
§ 250.731 (c)	BOP	BSEE Approved Verification Organization[5]	See Footnote	47
§ 250.731 (d)	BOP	BSEE Approved Verification Organization	See Footnote 5	48
§ 250.731 (e)	BOP	$3.3	$0.331	49
§ 250.731 (f)	BOP	BSEE Approved Verification Organization	See Footnote 5	50
§ 250.732	BOP	$231	$23	51
§ 250.732 (a)	BOP	BSEE Approved Verification Organization	See Footnote 5	52
§ 250.732 (b)	BOP	$45	$4.5	53
§ 250.732 (c)	BOP	BSEE Approved Verification Organization	See Footnote 5	54
§ 250.732 (d)	BOP	$1.3	$0.13	55
§ 250.732 (e)	BOP	BSEE Approved Verification Organization	See Footnote 5	56
§ 250.733	BOP	BSEE Approved Verification Organization	See Footnote 5	57
§ 250.733 (b)	BOP	Not currently calculated		58
§ 250.733 (e)	BOP	$5.5	$0.6	59
§ 250.733 (f)	BOP	Not currently calculated		60
§ 250.734	BOP	Contributes to BOP replacement	See line 85	61
§ 250.734 (a)(1)	BOP	Contributes to BOP replacement	See line 85	62
§ 250.734 (a)(3)	BOP	Contributes to BOP replacement	See line 85	63
§ 250.734 (a)(4)	BOP	Contributes to BOP replacement	See line 85	64
§ 250.734 (a)(5)	BOP	Not currently calculated	See line 85	65
§ 250.734 (a)(6)	BOP	Contributes to BOP replacement	See line 85	66
§ 250.734 (a)(15)	BOP	Contributes to BOP replacement	See line 85	67
§ 250.734 (a)(16)	BOP	Contributes to BOP replacement	See line 85	68
§ 250.734 (b)	BOP	$48	$4.8	69
§ 250.734 (c)	BOP	$3.3	$0.33	70
§ 250.735 (a)	BOP	$48	$4.8	71
§ 250.737 (d)	BOP	$237	$23.7	72
§ 250.737 (d)(5)	BOP	Cost is included in Parent Rule	See line 72	73
§ 250.737 (d)(12)	BOP	Cost is included in Parent Rule	See line 72	74
§ 250.737 (d)(13)	BOP	Not currently calculated		75
§ 250.738 (b)	BOP	Not currently calculated		76
§ 250.738 (j)	BOP	Not currently calculated		77
§ 250.738 (o)	BOP	$48	$4.8	78
§ 250.738 (p)	BOP	Not currently calculated		79
§ 250.739 (b)	BOP	$8,968	$897	80
§ 250.743 (c)	Well Design	$0.433	$0.043	81
§ 250.746 (e)	BOP	$123.8	$12.4	82
Safe Drilling Practices	RTM	Real Time Monitoring	See line 41	83
Shearing Requirements	BOP	Contributes to BOP replacement	See line 85	84
BOP Replacement (Result of Multiple Regulations)	BOP	$2,080	$208	85
Packer and Bridge Plug Inventory Loss (Result of Multiple Regulations)	Tubing and wellhead equipment	$32.1	$3.2	86
BSEE Approved Verification Organization	BAVO	BSEE Approved Verification Organization	See Footnote 5	87
Total		**$31,830.5**	**$3,183.1**	88

[5] BSEE Approved Verification Organizations (BAVO) are not defined by the regulations and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or other possible effect.

Estimated costs are identified by rule section, subsection, or, when necessary, individual line item where multiple regulations cumulatively contributed to an effect. For more specific explanations and analysis of the regulations cited in this table please see section 8, BSEE Rules and Regulations Appendix. The cost of regulations is calculated based on Quest's "Base Development Scenario" for the Gulf of Mexico and is the projected activity levels for various offshore oil and natural gas related activities based on current regulations without the proposed rule. Actual direct costs are likely to be lower due to wells not drilled due to the rule. This is discussed in section 5, Impact on Development.

The average annual costs to industry participants of the proposed rule are projected at around $3.2 billion per year from 2017 to 2026. Cumulative 10-year costs are estimated at over $32 billion. (Figure 2)

Figure 2: Estimated Annual Cost Rule by Category – 2017 to 2030 ($Millions)



Source: Quest Offshore Resources, Inc.

Costs are projected to rise rapidly in the early years of adoption due to implementation costs and the required replacement of equipment through years 5-7, before falling beginning in 2022 as implementations costs and the replacement of equipment slows. Costs begin to rise again in 2025 as those costs that are closely tied to activity levels (especially well costs) increase with activity levels. Additionally, certain areas of operations are expected to carry higher costs than others. For example, costs associated with well design regulations are projected at over $1.6 billion per year from 2017 to 2026 a total of over $15.6 billion over the same period, while costs associated with changes to BOP regulations are projected at just over $1.2 billion a year from 2017 to 2026 for a total of $12 billion over the same period. (Table 6)

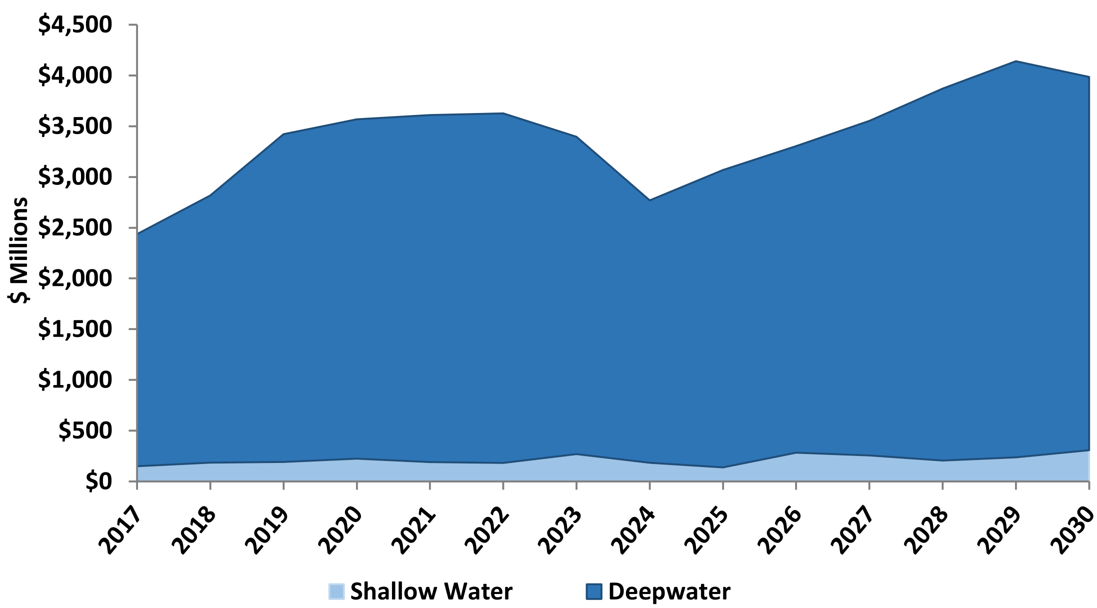
Table 6: Ten Year Direct Cost Estimates – Base Development Case ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419	$978	$1,041	$1,052	$11,846
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14	$13	$12	$15	$127
Containment	$113	$114	$179	$181	$190	$99	$97	$98	$85	$86	$1,241
Rig Requirements	$204	$205	$205	$215	$239	$239	$240	$244	$247	$250	$2,288
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56	$63	$63	$50	$670
Tubing and Wellhead Equipment	$33	$1	$1	$1	$1	$1	$1	$1	$1	$1	$38
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551	$1,357	$1,601	$1,830	$15,620
Grand Total	$2,421	$2,800	$3,402	$3,547	$3,589	$3,606	$3,378	$2,753	$3,050	$3,284	$31,831

Source: Quest Offshore Resources, Inc.

Although the proposed rule is expected to increase costs for wells and projects in all water depths in the Gulf of Mexico, the effect is expected to be felt disproportionately in deep and ultra-deep water depths, areas which carry a disproportionally higher operating cost and are projected to account for the majority of activity in the region. (Figure 3) Under the base development scenario, average annual costs for deepwater activity are projected to increase by over $3 billion a year from 2017 to 2026, with total cumulative costs of $30 billion from 2017 to 2026. Increased costs for shallow water activity are projected to be around $200 million dollars annually, with cumulative costs from 2017 to 2026 projected at nearly $2 billion.

Figure 3: Estimated Annual Costs Deepwater vs. Shallow Water – Base Development Scenario ($Millions)



Source: Quest Offshore Resources, Inc.

Increased costs, coupled with wells and projects not able to be developed, are expected to have a significant effect on Gulf of Mexico OCS activity levels in the forecasted period, with effects from this reduced activity level felt in employment, GDP, and other indicators. These effects are described in the following sections of the study, section 5, Impact on Development and section 6, Macro-Economic Impact Conclusions.

3.1 Ten Year Cost Comparison – Study Estimates vs. BSEE

Although the cost impacts associated with the proposed rule “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” developed by this study were developed independently and without reference to additional studies analyzing the proposed regulatory changes and effects, the following table provides a ten year cost comparison to BSEE’s own cost impact study for reference. It is important to note that due to the time limitations associated with this study, both additional costs and possible cost savings calculated by BSEE, are not included in this study. Additionally, as this study projects that costs associated with this study will begin to be required in 2017, the reference year (year 1) for this cost comparison is 2017 for this study compared to 2015 for the BSEE analysis. It is also important to note that both the BSEE cost analysis and that provided by this study take into account the varied implementation timelines of the proposed regulations and both studies do not address the costs associated with the proposed rule. (Table 7)

Table 7: BSEE Ten Year Cost Comparison Table ($Millions)

Year	BSEE Estimates	Study Estimates
Year 1	$165	$2,421
Year 2	$77	$2,800
Year 3	$77	$3,402
Year 4	$77	$3,547
Year 5	$77	$3,589
Year 6	$99	$3,606
Year 7	$77	$3,378
Year 8	$77	$2,753
Year 9	$77	$3,050
Year 10	$77	$3,284

Source: Quest Offshore Resources, Inc.

The overall industry-incurred cost due to the proposed rule change within the first ten years of implementation of the studies displays significant divergence, under which Quest has predicted an average of around $3.2 billion per year while BSEE foresees $120 million per year. Furthermore, Quest also projects additional industry effects throughout the supply chain due to the inability to develop numerous projects, which are then removed from the forecast.

Allocation of Costs

This study does not attempt to allocate the projected costs associated with the adoption of the proposed rule to specific industry participants due to the difficulty of that process. Each of the individual rules’ effects are likely to be felt by numerous groups of industry participants and the specific allocation of these costs is unlikely to be accurately predicted. However, the vast majority of the costs associated with the proposed rule are expected to affect certain groups disproportionately. As an example, the costs associated with rules affecting subsea blow out preventers are expected to be borne primarily by drilling contractors operating floating drilling rigs and the limited number of original equipment manufacturer who manufacture these pieces of equipment. In comparison, the costs associated with rules which are focused on well construction are expected to be borne mostly by oil and natural gas operators with the majority of the cost borne by the limited operators active in deep and ultra-deep waters. Implementation of the proposed rule as currently written would likely also lead to a change in the operators and contractors active in the Gulf of Mexico OCS, as smaller companies may reduce participation in the area due to the increased costs. Therefore while this study does not specifically allocate costs to specific industry participants it is important to emphasize that the costs of the regulations will be primarily borne by those industry participants engaged in the types of activity most affected by the proposed rule.

Containment Costs Already Borne by Industry

The increased costs resulting from the adoption of the proposed rule, calculated above, exclude many costs already borne by the industry which would not be required prior to the implementation of the proposed rule. The largest single investment by oil and natural gas operators and contractors has been on containment equipment including subsea capping stacks, storage equipment, and vessels to deploy this equipment and process contained fluids. Neither this investment, nor the impacts of that spending are included in the costs above nor are the employment or GDP impacts, as they were not required prior to the proposed rule. However, the study includes an estimate of this spending for reference. The industry has invested in two separate containment systems, organized as the Marine Well Containment Company (MWCC) and the Helix Well Containment Group (HWCG). Both of these systems have required significant upfront investment as well as ongoing spending. MWCC and its member companies have spent an nearly $1.5 billion since its founding, with investment in two tankers designed to process oil and gas, multiple capping stacks and a variety of other equipment. HWCG, which has utilized some existing equipment such as the Helix Q4000 and the Helix Producer 1 has, with its member companies, invested approximately $780 million into well containment preparation since its founding. Beyond equipment, the costs associated with these containment organizations range from shorebases, to preposition equipment, to training for the utilization of the equipment and continued maintenance.

Effect on Other U.S. OCS Areas

Although the costs and other impacts associated with the proposed rule are calculated solely as it effects Gulf of Mexico OCS activity, the rule will affect all U.S. Federal OCS areas including Alaska, existing production on the Pacific coast and any future activity in areas where oil and natural gas exploration activity is not currently taking place. These areas include the Atlantic coast (where there is a currently proposed lease sale expected to take place in 2021 in limited areas of the central and southern Atlantic coast), the Eastern Gulf of Mexico, and areas of the Pacific coast which are currently closed to new oil and natural gas activity. Although many of the costs associated with the proposed rule would be similar to those stemming from the rule in the Gulf of Mexico, other costs would likely be higher, especially on a per-well or per-project basis. The section of regulation most likely to see higher costs in new areas (such as the Atlantic coast) is projected to be containment, as the prepositioning of materials, capping stacks and vessels for operations in the Atlantic would likely be spread over far fewer wells and projects, especially initially.

Cost Effects of Proposed Regulations

The detailed technical and economic analysis of the projected costs of the proposed rule "developed in this study indicate that the effects of the adoption of this proposed rule would likely impose a significant burden on participants in the Gulf of Mexico OCS oil and gas industry. In addition, these costs and requirements are likely to reduce overall OCS oil and natural gas development relative to what is projected to occur with current regulations. The lost activity is due to increased costs which may make some wells or projects uneconomic, delays reducing the number of wells drilled per year, and the inability to drill certain wells or develop certain projects and meet new technical requirements of the rule. The projected impact of the proposed rule on Gulf of Mexico oil and natural gas development and the subsequent impacts on spending by the industry, oil and natural gas production, employment, GDP and government revenues are discussed in the next section.

Section 4 - Impact on Development

Natural gas and crude oil exploration and production activities offshore of the US provide large contributions to employment, gross domestic product and state and federal government revenues. To quantify the effects of the proposed rule, the study forecasted activity levels for Gulf of Mexico OCS oil and gas activity with and without the proposed rule. The forecasted activity levels include the number of wells drilled, projects executed, total production, and spending. These activity forecast drive the spending projections from which GDP, employment and government revenue effects are estimated.

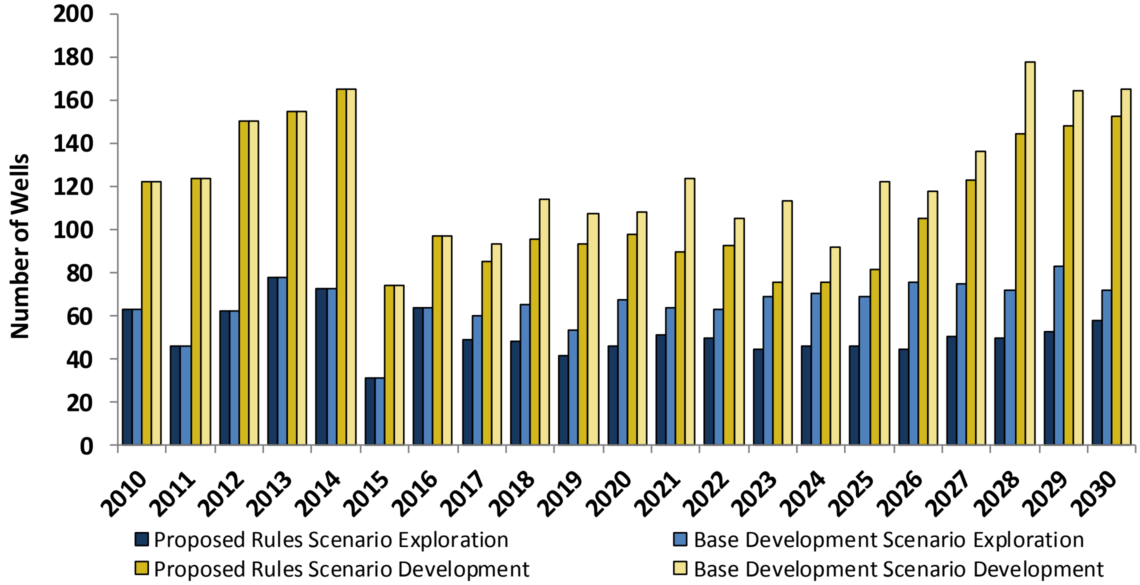
4.1 Wells Drilled

Exploration appraisal and development drilling is used to identify, confirm, delineate, and produce oil and natural gas, making it one of the most important offshore oil and natural gas activities. Drilling is a very capital intensive process employing drilling rigs that require large crews as well as significant quantities of consumables ranging from food and fuel to drill pipe and fluids. Drilling rigs (mobile offshore drilling units – MODU's) and platform rigs must constantly be resupplied and crewed, and thus lead to high levels of activity in the areas and ports that support offshore drilling activity.

Drilling activity in the US Gulf of Mexico is projected to continue to be robust throughout the forecast period as exploration of new geologic areas continues and development of the known production areas progresses. The region is projected to see around 960 exploration wells drilled and around 1740 development wells drilled between 2017 and 2030 under the current regulatory environment, and around 670 exploration wells and around 1335 development wells under the proposed rule scenario. This represents a 26 percent decrease in drilling activity over the study period.

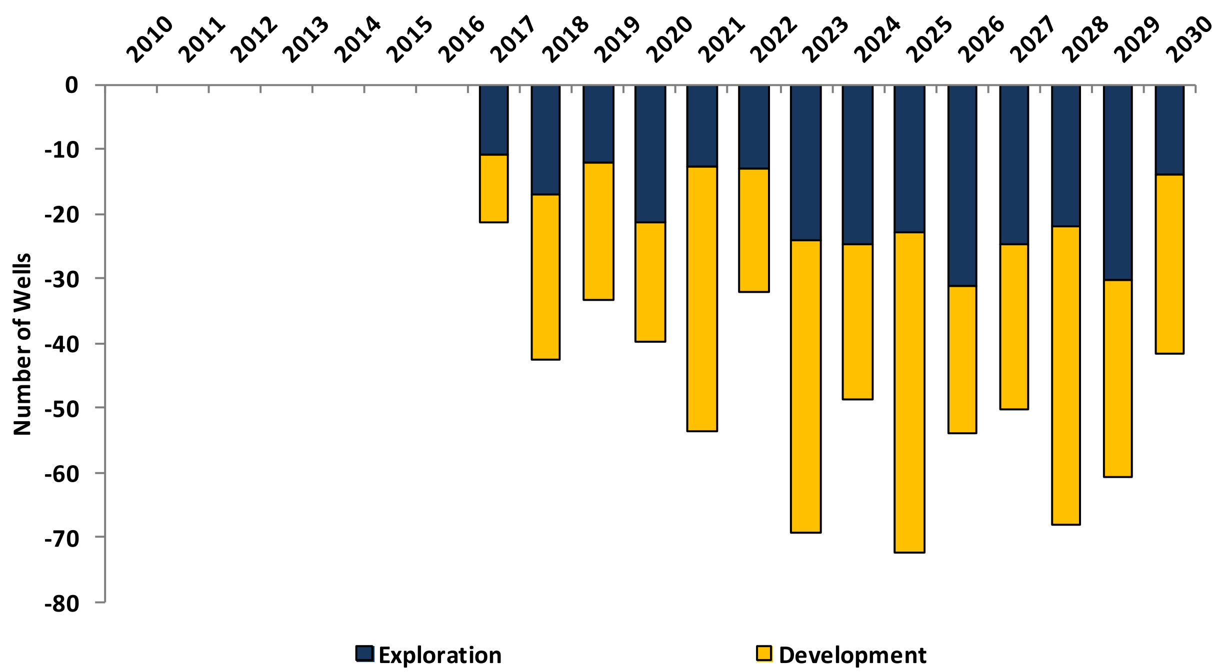
The decrease in drilling under the new regulations, as mentioned in the regulation section, is primarily due to the effects of §250.414, "Planned safe drilling margins" as well as higher costs associated with the regulations. Since many of the wells that are projected to be drilled in the Gulf are in particularly deep water, and located in high pressure, high temperature reservoirs, or are being drilled in depleted reservoirs, some of these wells are expected to be no longer technically possible to drill or complete under the new regulations, and others, particularly development wells, may become economically non-viable. The effects of the regulations, as written, are projected to have a significant influence on overall drilling levels (Figure 4). The proposed rule scenario results in an average of around 20 less exploration wells drilled per year and around 29 less development wells per year. (Figure 5)

Figure 4: Number of Wells Drilled by Well Type and Scenario - Exploration and Development



Source: Quest Offshore Resources, Inc.

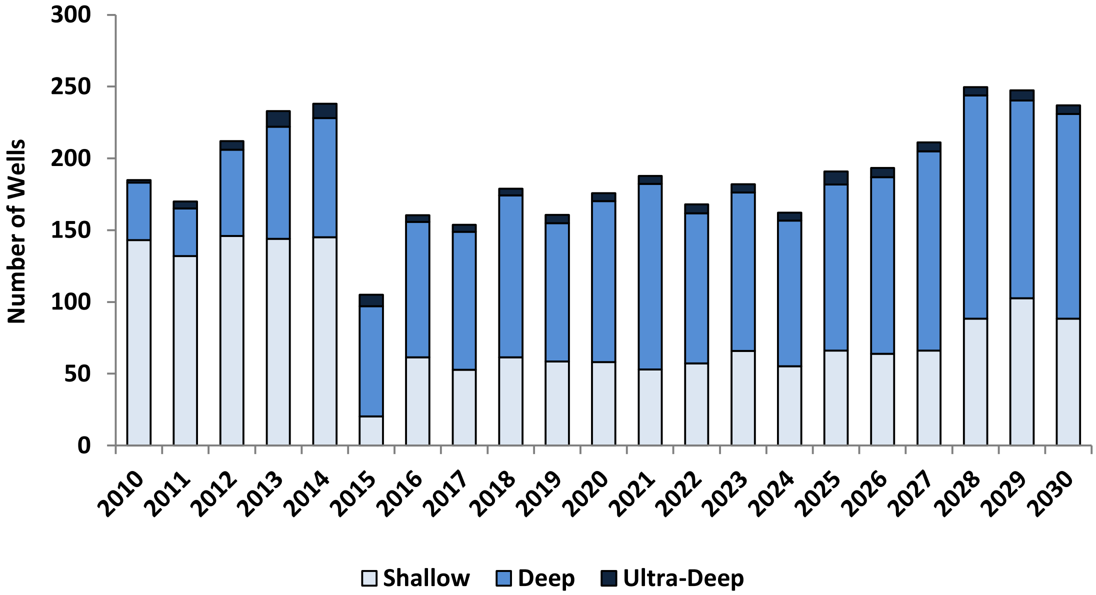
Figure 5: Difference between Number of Wells Drilled in Base Development and Proposed Rule Scenarios



Source: Quest Offshore Resources, Inc.

Drilling activity as a whole has shifted from primarily shallow water areas into progressively deeper and higher pressure areas, as the reservoirs in shallower areas mature and new fields are discovered. (Figure 6)

Figure 6: Number of Wells Drilled by Water Depth and Year – Base Development Scenario



Source: Quest Offshore Resources, Inc.

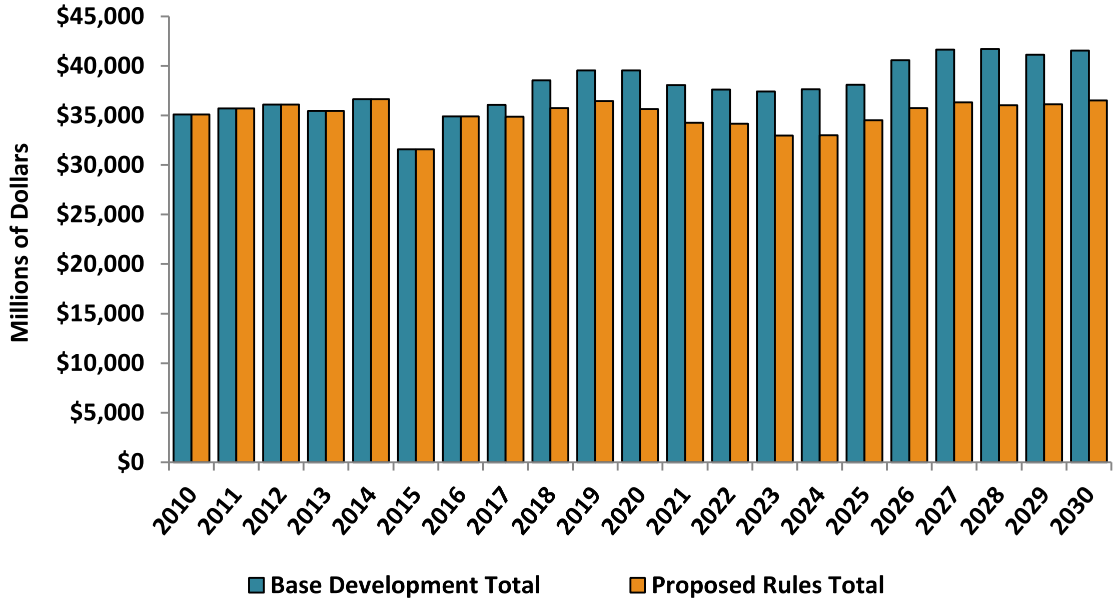
Under the base development scenario, a total of around 2,700 wells are projected to be drilled from 2017 to 2030, with three percent of wells projected to be located in ultra-deep water, 62 percent of the wells projected in deep water and 35 percent projected in shallow water. Under the new regulations, approximately around 690 fewer wells are projected to be drilled from 2017 to 2030, a 26 percent decline, with similar water depth distributions. Over the 10-year 2017 to 2026 period the projected number of wells projected not to be drilled equals around 470, with an average of 20 fewer exploration wells per year and 29 fewer development wells.

4.2 Projects Executed

Developing an offshore project is a complex process that requires a significant amount of time, planning and high levels of capital investment. Project executions and their respective timelines are the best indicator of overall market health, as they can be viewed as representative of total trends in production, employment and revenue for the broad market.

Over the forecasted period of this study (2017-2030), 15 standalone floating production projects and 49 fixed platform-based oil and natural gas projects are projected to begin production under the base development scenario. These projects and other additions to the existing projects in the Gulf collectively represent $549 billion in capital and operational spending over the course of the forecast period. As a result of the burdens placed on project and drilling economics by the proposed rule scenario, the total number of floating production units developed is projected to decrease by 20% and fixed platforms are projected to decrease by nearly 33% under the new regulations. Collectively, this reduction in activity is projected to lead to a decrease in total spending of nearly 30 percent, which would be worth around $52 billion. (Figure 7)

Figure 7: Total Yearly Project Spending by Scenario



Source: Quest Offshore Resources, Inc.

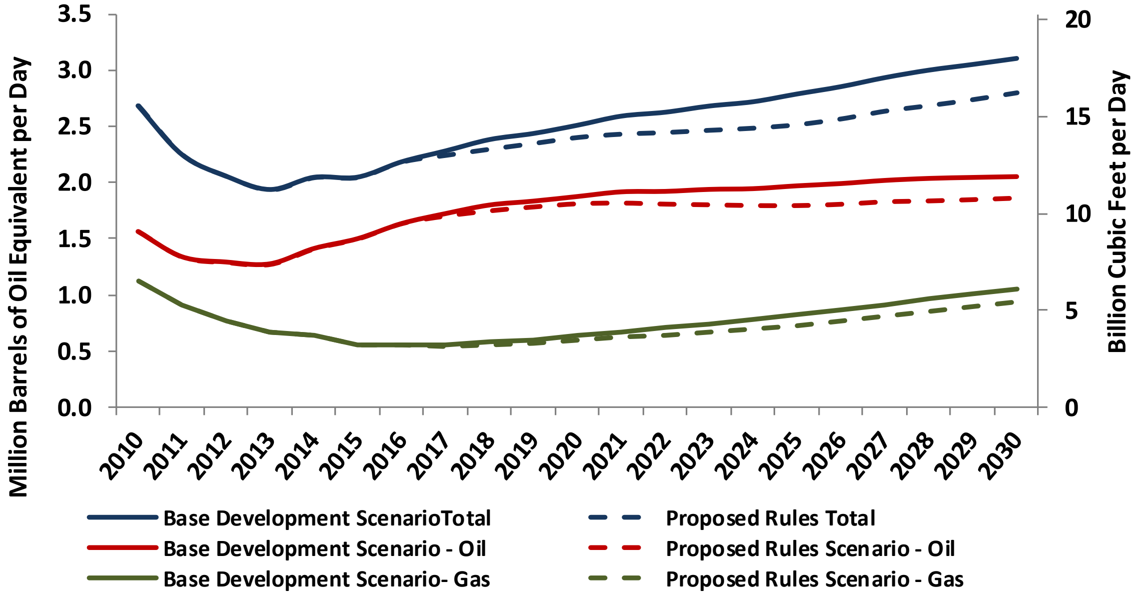
Total project spending is primarily driven by overall activity levels, and partially driven by the project design and size of the projects executed. Apart from water depth, project size is typically defined by reservoir characteristics, hydrocarbon volumes and expected production, which define the timeline and capital investment required to develop the project. Larger projects typically require more wells and a longer development period, in addition to requiring increased material resources and larger equipment such as platforms, production trees and pipelines. Smaller projects, on the other hand, often rely on larger projects for certain types of infrastructure such as pipelines or processing facilities. This leads to the spending, production and other effects on a per project basis to be highly variable.

4.3 Production

The number of projects developed, coupled with reservoir size and reservoir productivity, is the main determinant of oil and natural gas production levels. Most oil and natural gas reservoirs contain a combination of oil, natural gas, water, and other native substances such as sand, sulphur, CO2, and salt, though some reservoirs may contain nearly all oil or all natural gas. In order to forecast aggregate production, each project was modeled based on production curves for similar developments, taking into account the start-up, ramp-up, peak, and decline timing, as well as the expected hydrocarbon mix.

This study projects that production in the Gulf of Mexico will be around 2.28 million barrels of oil equivalent (BOE) per day in 2017 and is projected to grow relatively consistently throughout the period, at a compound annual growth rate of roughly 2.5 percent per year from 2017 to 2030. Production is projected to reach 3.10 million BOE per day by 2030, with approximately 66 percent of production oil (2.05 million BOE per day), and 34 percent of the production natural gas (1.05 million BOE per day). Under the proposed rule, Gulf of Mexico production is forecasted to be reduced by nearly 15% and 0.48 million BOEPD by 2030, with approximately 67 percent of production being oil (1.74 million BOE per day), and 33 percent of the production being natural gas (739 thousand BOE) under the proposed regulations. (Figure 8)

Figure 8: Production by Type by Scenario – MMBOED 2010 to 2030



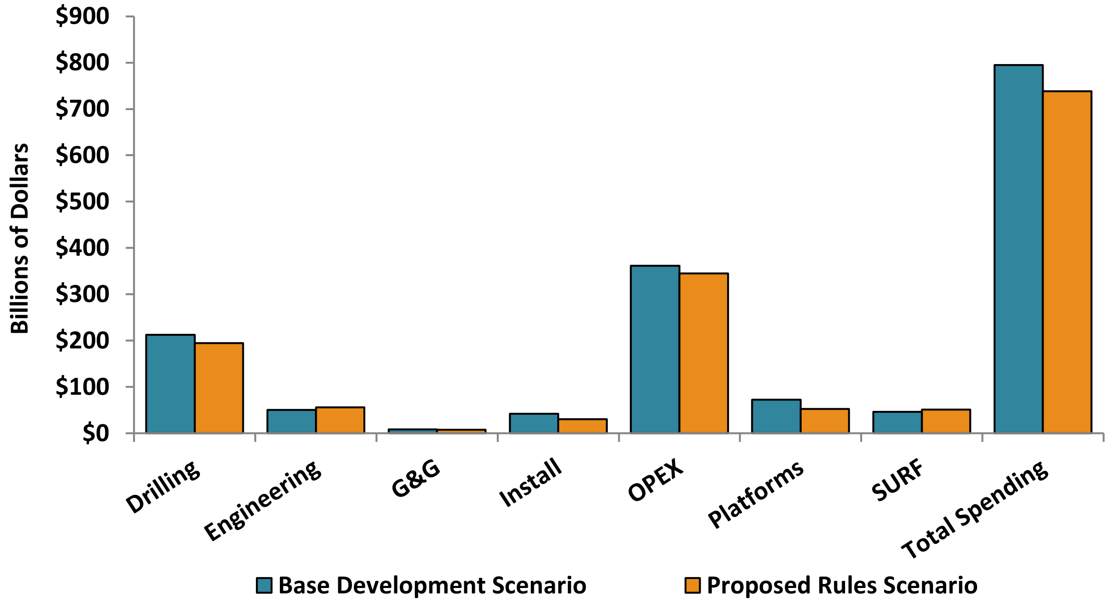
Source: Quest Offshore Resources, Inc.

4.4 Total Spending

Offshore oil and natural gas exploration and development is a capital intensive process. Offshore projects require exploratory seismic surveys, drilling, production equipment, engineering, operational expenditures including the ongoing supply of consumables, and maintenance as well as other spending to be found and developed. The total cumulative spending from offshore oil and natural gas development is projected to be nearly $550 billion between 2017 and 2030 under the base case scenario and $493 billion under the proposed rule, a yearly average of $39.2 and $35.2 billion respectively, which equals an average decline of $4 billion per year. This represents a 10.3 percent decrease in total spending as a result of the proposed rule changes.

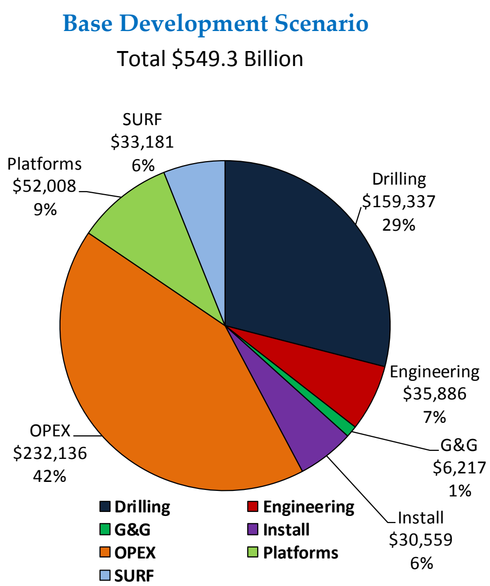
For the purposes of this report, spending is divided into seven main categories: Drilling, Engineering, G&G, Installation, OPEX, Platforms, and Subsea Umbilicals, Risers and Flowlines (SURF). Each category encompasses a major type of exploration and production activity and has a significant influence on overall spending. Both development scenarios estimate total spending amounts that rise slightly through the end of the decade, decline briefly, then recover due to normal project development cycles. Under the proposed rule case, very little spending growth is projected during the forecast period. (Figures 9 & 10)

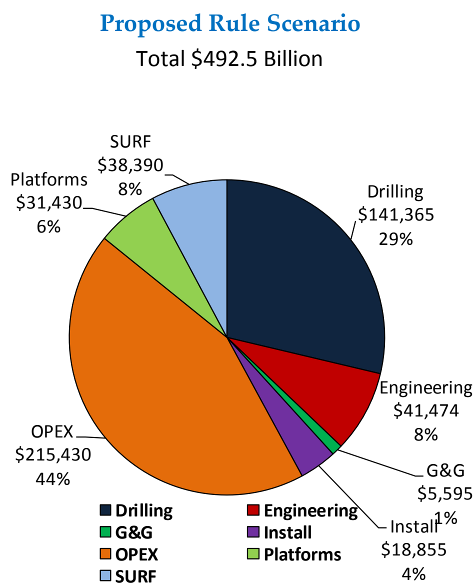
Figure 9: Cumulative Spending by Category and Scenario – 2017 to 2030



Source: Quest Offshore Resources, Inc.

Figure 10: Share of Total Spending by Category and Case – 2017 to 2030 ($Billions)



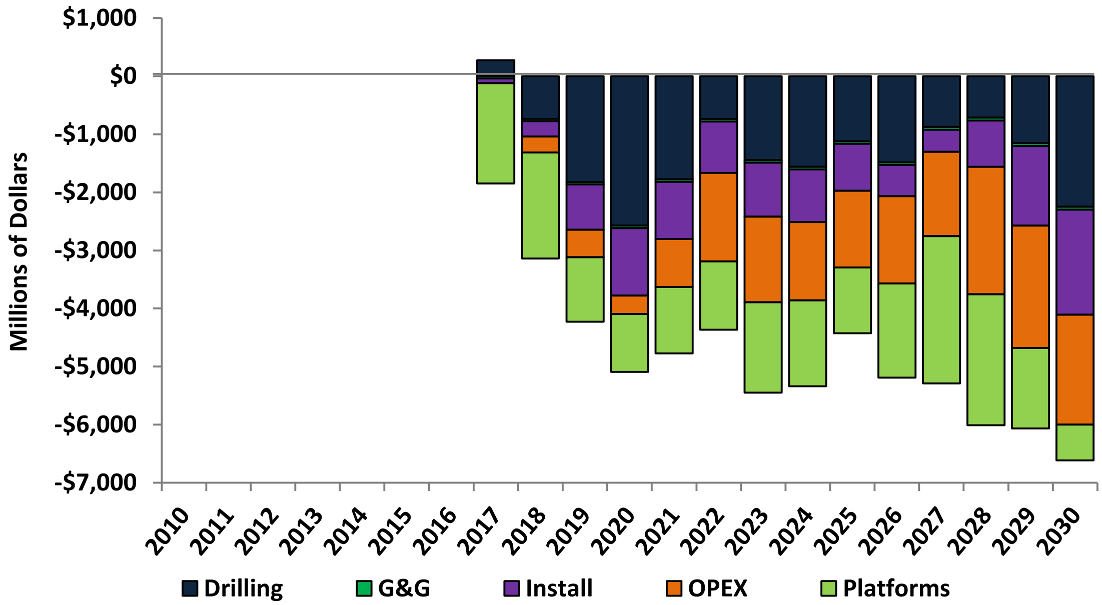


Source: Quest Offshore Resources, Inc.

The proposed rule is anticipated to increase some types of spending for Gulf of Mexico oil and natural gas development. However, increased spending due to compliance with the proposed rule is anticipated to be more than offset by reduced spending in areas that are impacted from fewer wells drilled and projects developed. Therefore, as a result of the proposed rule overall spending for Gulf of Mexico oil and natural gas activity is projected to decline.

The platform CAPEX, drilling, OPEX, installation, and G&G markets are all projected to see decreased spending under the proposed rule scenario, with average yearly spending decreases of $1.47 billion, $1.28 billion, $1.19 billion, $836 million and $44 million respectively (Figure 11)

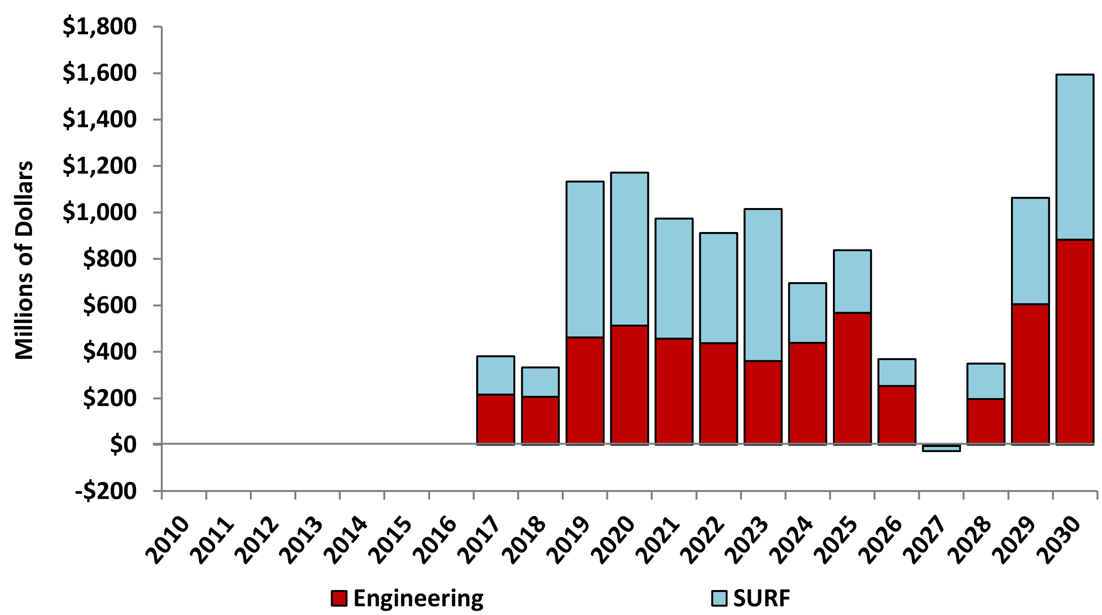
Figure 11: Projected Spending Decreases under Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

The platform Engineering and SURF markets are both projected to see increased spending under the proposed rule scenario, with average yearly spending increases of $399 million and $372 million respectively. A more detailed look at these market segments may be found below (Figure 12 & Table 8).

Figure 12: Projected Spending Increases under the Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

Table 8: Base Development and Proposed Rules Scenario Spending Comparison 2017 to 2030 ($Millions)

Category	Annual Base Development Scenario ($ Millions)	Annual Proposed Rules Scenario ($ Millions)	Annual Net change in Spending ($ Millions)	% Change in Spending
Drilling	$11,381	$10,097	-$1,284	-11%
Engineering	$2,563	$2,962	$399	16%
G&G	$444	$400	-$44	-10%
Installation	$2,183	$1,347	-$836	-38%
OPEX	$16,581	$15,388	-$1,193	-7%
Platforms	$3,715	$2,245	-$1,470	-40%
SURF	$2,370	$2,742	$372	16%
Total	**$39,237**	**$35,181**	**-$4,056**	**-10%**

Source: Quest Offshore Resources, Inc.

G&G

Seismic (G&G) spending is normally associated with imaging of possible reservoirs prior to exploration drilling and thus takes place primarily at the early stages of a project's lifecycle. Although critically important to long-term development, seismic spending is a relatively low percent of overall spending at an average of $444 million per year, or roughly one percent of overall spending from 2017 to 2030 in our base development case, and $399.6 million and around one percent per year in our proposed rule case.

Drilling

Given the expense and logistics requirements of offshore drilling, where rigs command significant day rates and operational costs, drilling expenditures represent one of the largest sources of spending for any offshore project. Total drilling costs from 2017 to 2030 for exploration and development drilling combined are projected to average nearly $11.4 billion per year in the base development scenario and $10.1 billion in the proposed rule scenario, indicating a $1.3 billion decrease in activity due to a drop in well demand partially offset as a result of the increased costs of the proposed rule. Drilling accounts for 29 and 26 percent of each case's total spending respectively.

Engineering

Engineering spending takes place at all stages of an offshore project's lifecycle, including exploration, project development and the operational phase. These activities vary from overall project-focused engineering to the engineering of very specific equipment and components. Engineering spending is projected to average $2.5 billion per year from 2017 to 2030 in the base development scenario. In the proposed rule scenario due to the engineering burdens necessitated by the regulation, engineering spending is projected to average $3.0 billion per year. These spending categories account for around seven and eight percent of total spending in their respective cases.

Platforms & SURF

The majority of equipment utilized in developing offshore oil and natural gas fields can be found on either the platform (both fixed and floating) or subsea, as a part of the SURF (subsea equipment, umbilicals, risers and flowlines) category. This equipment is purchased and constructed prior to production of oil and natural gas, though more can be added to a project after first production. The types of equipment include complicated structures like floating platforms that weigh tens of thousands of tons, complex subsea trees that control wells at the ocean floor and miles of pipeline that transport the produced oil and gas back to shore. In addition to these large, expensive pieces of equipment, some of the components required for offshore production are less complex (e.g. offshore accommodation modules, metal mats placed on the seafloor to hold other equipment, or stairwells).

Due to the varying timelines for procurement of equipment, spending for platforms and SURF equipment is more variable year to year than most other offshore exploration and development spending. Platform spending is projected to average over $3.7 billion per year from 2017 to 2030 in the base development scenario and $2.2 billion per year under the new regulations, due to decreased project activity. SURF spending is projected to rise under the new regulations due to increased per-well spending on the associated systems. Due to these effects, in the base case forecast $2.4 billion are projected to be spent each year from 2017 to 2030, and in the proposed regulation case an average of $2.7 billion of spending are projected to be attributable to SURF hardware and associated activity. These costs represent 6.0 and 7.0 percent of total spending in their cases respectively.

Installation Activity

The Installation of platforms and SURF equipment is normally carried out by multiple vessels, each with specialized functions such as pipe-lay or heavy-lift. Some vessels might lay large diameter pipelines (14 inch+), while other vessels lay smaller diameter infield lines (2-10 inches) or lift equipment, and install hardware. Other specialized vessels supply drill-pipe, fuel and other fluids, and food. Nearly everything installed offshore must first be prepared onshore at specialized bases in the region prior to installation. Equipment is sometimes transported to the field on the installation vessels themselves, and at other times is brought to the field on specialized barges or transportation vessels. Installing offshore equipment often requires complex connection or integration operations and uses vessels that can command day rates of over $1 million.

Due to lower project development activity in the proposed rule scenario, a significant decrease in installation activity is expected between the two cases for this subsection of the market. Between the 2017 and 2030 period, average annual installation spending is projected to be $2.2 billion per year under the current regulatory environment and over $1.3 billion under the proposed regulations, representing around six percent and just over three percent of total spending in each of the cases.

OPEX

Once the initial wells have been drilled and the necessary equipment installed, a field enters the operational phase, which requires manning and operating facilities and equipment, continuously supplying essential fluids and constant general maintenance. Due to the maturity of the market and the large amount of existing infrastructure, these operational expenditures (OPEX) are a significant source of ongoing spending by oil and gas companies within the region. However, much of the aging infrastructure in the Gulf is being removed, allowing expenditures on many assets to be rolled back or even stopped. In the base development scenario, operational expenditures are projected to decrease from over $17.6 billion in 2017 to $16.2 billion by 2030, mostly driven by a decrease in shallow water OPEX, which is offset by increasing deepwater OPEX. In the proposed rule scenario, there is less new activity to offset the decline, and the trend is even more pronounced. OPEX spending under the new rules is projected to decline from $17.6 billion to $14.2 billion per year, averaging $15.4 billion over the forecast period.

Section 5 - Macro-Economic Impact Conclusions

In order to further quantify the effects of the proposed rule, Quest constructed an economic analysis model to estimate changes in jobs, GDP, and governmental revenue. The estimates created throughout this section closely parallel spending and activity trends. Employment and GDP effects are calculated using the most recent Bureau of Economic Analysis' (BEA) RIMS II models in order to quantify the effects of domestic spending.

This analysis further underscores that the economic benefit of increased spending due to the adoption of the proposed rule as written will likely be outweighed by overall reductions in oil and natural gas exploration and development. The net economic analysis anticipated from the proposed rule is projected to result in significant declines in employment, GDP, and federal revenue from 2017 forward.

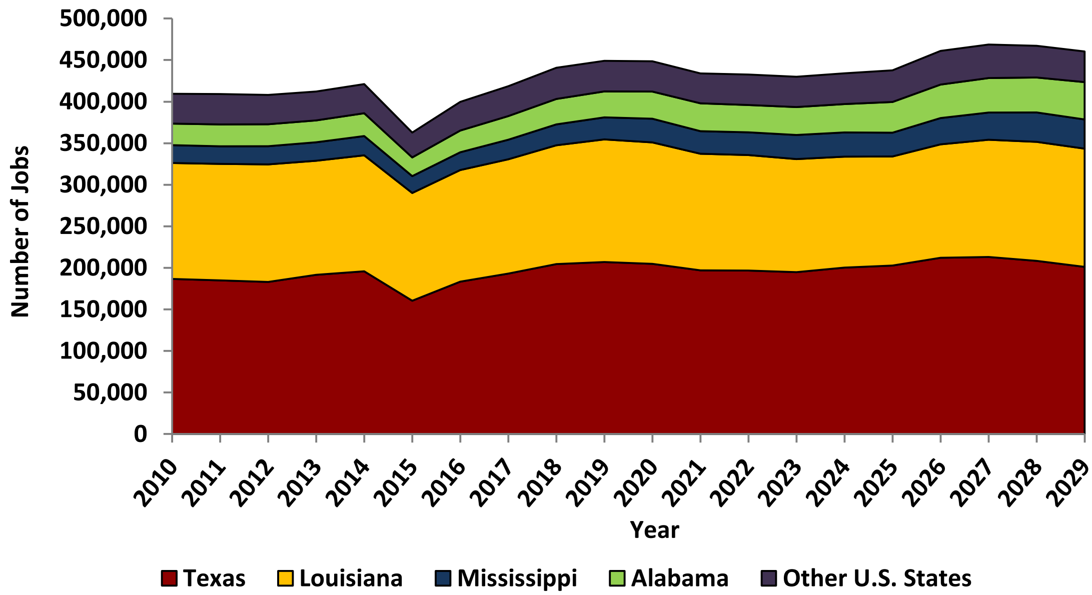
5.1 Employment

The offshore oil and gas industry has a long history of significant employment throughout the nation and in particular in the Gulf Coast states. Continued investment in offshore infrastructure has built a buoyant and diverse supply chain that has historically provided high wages to significant numbers of white and blue collar laborers. Most recent estimates through Quest's application of the BEA economic models have suggested that total employment supported by industry spending is approximately 363 thousand in 2015 with nearly 142 thousand direct industry jobs and an additional 220 thousand jobs provided from indirect and induced industry spending[6].

Employment is expected to grow throughout the forecast, as continued project investment, particularly in deep and ultra-deep waters is projected to lead to employment growth throughout the region. Gulf of Mexico OCS activity-driven employment within the U.S. is likely to grow from 363 thousand jobs in 2015 to more than 466 thousand by 2030, which equals an additional 104 thousand jobs and represents 29 percent growth. No major shifts are expected within the state employment distribution, as Texas and Louisiana are expected to continue to be the most significant beneficiaries of offshore oil and gas with 160 thousand and 130 thousand jobs in 2015 respectively, and 202 thousand and 145 thousand jobs projected by 2030. (Figure 13)

[6] Indirect jobs are those related to the oil and natural gas supply chain. Induced jobs are created from more income that is spent throughout the economy.

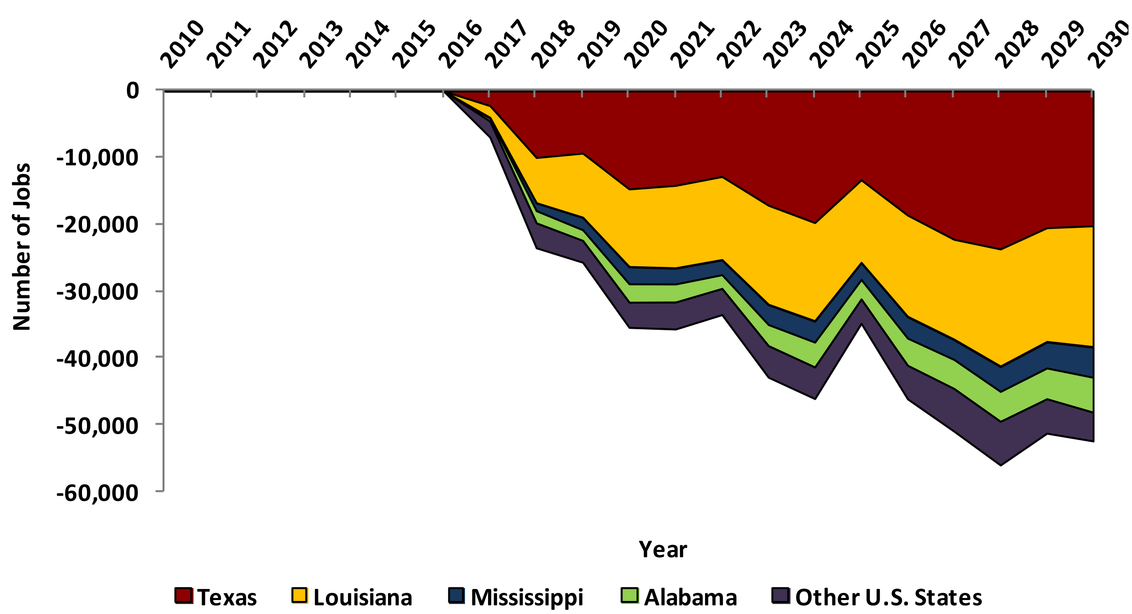
Figure 13: Jobs by State - Base Development Scenario



Source: Quest Offshore Resources, Inc.

With the proposed rule, yearly employment supported is projected to diverge from the base forecast, continuing to widen in the later years with over 50 thousand yearly jobs displaced through lost offshore activity by 2030. Gulf of Mexico oil and natural gas development is projected to support fewer jobs with the proposed rule despite increases in spending by the industry to meet the rule's requirements. This is due to fewer wells drilled and lower overall spending. (Figure 14)

Figure 14: Jobs by State - Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

This lower employment level is likely to primarily affect the Gulf Coast, with Texas and Louisiana expected to see employment levels of 20 thousand and 18 thousand jobs lower by 2030. This represents ten percent and 12 percent lower projected Gulf of Mexico OCS oil and natural gas production employment respectively. (Table 9)

Table 9: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030

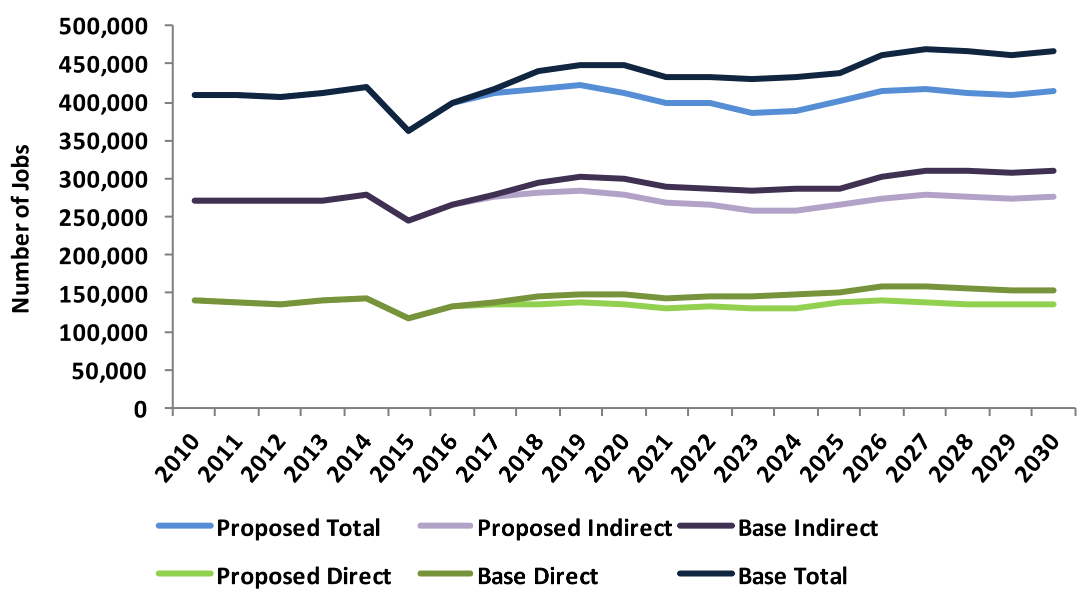
Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409,484	409,165	408,102	412,231	421,157	362,797	399,745	418,592	440,788	449,152	448,591
Proposed Rule	409,484	409,165	408,102	412,231	421,157	362,797	399,745	411,674	417,244	423,443	413,102
Difference	-	-	-	-	-	-	-	(6,918)	(23,544)	(25,709)	(35,488)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	433,987	432,658	429,997	434,125	437,702	461,102	468,727	467,236	460,408	466,541
Proposed Rule	398,256	399,091	387,026	387,946	402,826	414,877	417,656	411,089	409,033	414,002
Difference	(35,731)	(33,567)	(42,972)	(46,179)	(34,875)	(46,225)	(51,071)	(56,147)	(51,376)	(52,539)

Source: Quest Offshore Resources, Inc.

The BEA's RIMS II model allows the calculation of employment estimates for both direct jobs, (employment for those that work within the industry) and indirect and induced jobs (those created through the network of oil and gas operations as well as ancillary spending from the industry and its employees). Estimates for direct job numbers are expected to grow from 118 thousand to 154 thousand between 2015 and 2030, a 31 percent growth, while indirect jobs are expected to grow from 244 thousand to 311 thousand, a 27 percent growth. (Figure 15)

Figure 15: Direct vs. Indirect/Induced, and Total Employment – Base Development Scenario vs. Proposed Rule Scenario

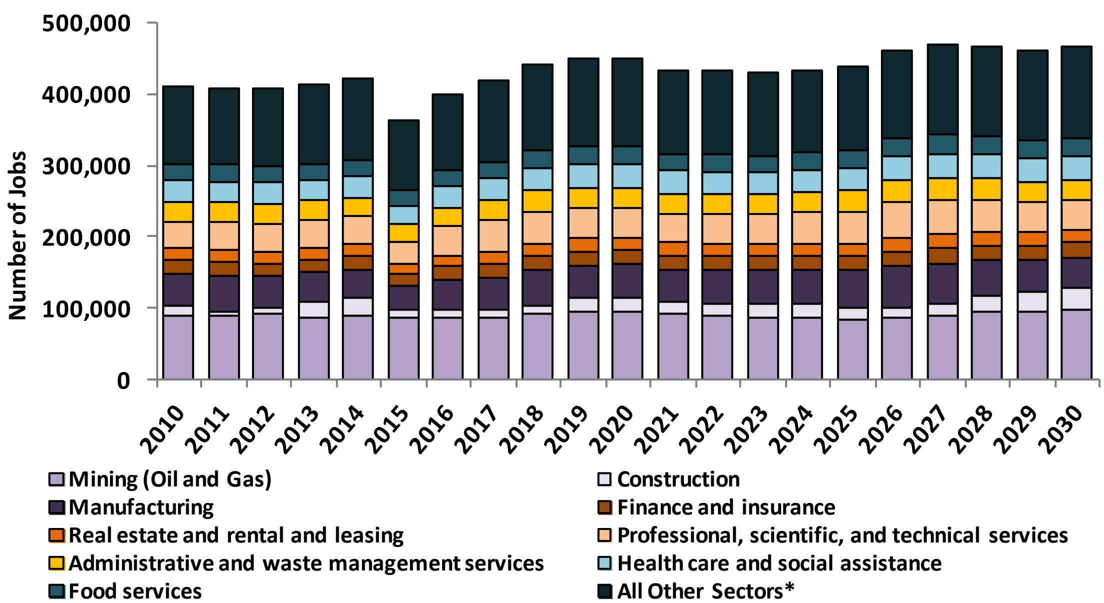


Source: Quest Offshore Resources, Inc.

The impacts of the proposed rule are expected to have the largest numeric effect on indirect jobs, with an expected net loss of 34 thousand jobs or a 12 percent reduction to the base case, while direct jobs are expected to see a smaller, net loss of 18 thousand jobs or 14 percent of projected employment in 2030.

The current offshore oil and gas supply chain has grown to include suppliers throughout the country and world and a multitude of companies. Development of offshore oil and natural gas projects involves a larger number of industries, which include, but are not limited to: mining (of natural resources including oil and natural gas production), manufacturing, professional, scientific, and technical services (engineering), manufacturing, and construction (installation). Combined, these industries are expected to see additional employment of around 50 thousand jobs by 2030, with employment growing from 162 thousand to 212 thousand jobs. Additional industrial sectors that benefit indirectly through induced employment are likely to see continued benefits throughout the study period due to Gulf of Mexico oil and natural gas development. These industries include among others, retail, finance and insurance, food services, and health care and social assistance. Employment in these industry sectors alone due to Gulf of Mexico oil and natural gas activities account for 25 thousand jobs on average in 2015 and is projected to reach 30 thousand jobs on average in 2030 under current regulations. (Figure 16)

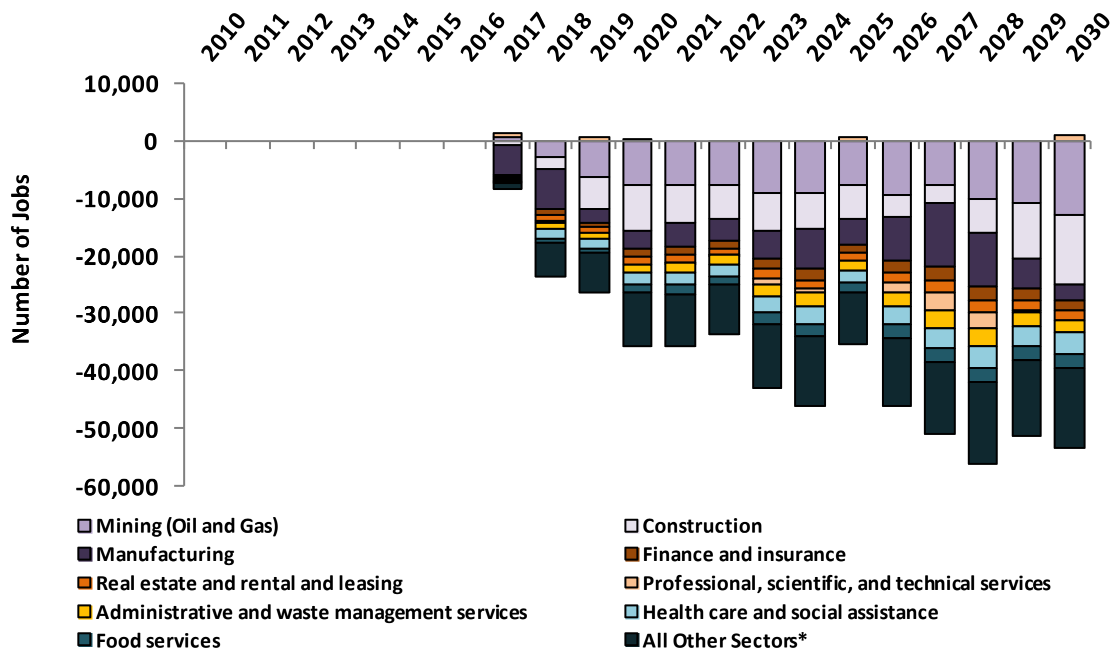
Figure 16: Jobs by Profession – Base Development Scenario



Source: Quest Offshore Resources, Inc.

The proposed regulations will have far reaching effects throughout the Gulf Coast economies as employment levels due to Gulf of Mexico oil and natural gas activities are projected to be 50 thousand lower as early as 2027 relative to employment projections under current regulations. These jobs are expected to be numerically focused within mining (oil and gas) and manufacturing, with both sectors seeing lower employment of around 12 thousand jobs in 2030. The construction (installation) sector has the largest employment impact proportionately over the study period, with a 44 percent decline in projected employment as the costs of the proposed rule slow new project development activity. Numerous other industries are likely to see declines in projected employment of around 10 percent within their professions while professional, scientific, and technical services (engineering) are expected to see slightly higher employment in certain years due to the increased engineering burden of the proposed rule. (Figure 17)

Figure 17: Jobs by Profession – Delta Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

5.2 GDP (Gross Domestic Product)

Potential gross domestic product (GDP) effects were calculated as a multiplier on spending within the U.S., further utilizing the BEA's RIM II model. The estimated effects of proposed rule changes are therefore likely to be strongly correlated to any shifts within spending, with international spending (mainly on platform fabrication) excluded, and should mirror the shifts throughout employment.

The current GDP impact of the Gulf of Mexico offshore oil and natural gas industry in the U.S. is estimated at $34.5 billion annually, and is projected to continue to grow to around $40 billion over the forecast period by 2030 – representing around 16 percent growth. The proposed rule, if enacted as written, is projected to lead to the GDP impact from Gulf of Mexico oil and natural gas activities being $4 billion lower in 2030. The cumulative 10-year loss of GDP from 2017 to 2026 is estimated at $27 billion (Table 10).

Table 10: Estimated GOM Supported GDP by Scenario – 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$36,077	$38,084	$38,862	$38,699
Proposed Rule	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$34,726	$36,937	$37,817	$36,857
Difference	$0	$0	$0	$0	$0	$0	$0	($1,351)	($1,147)	($1,045)	($1,841)

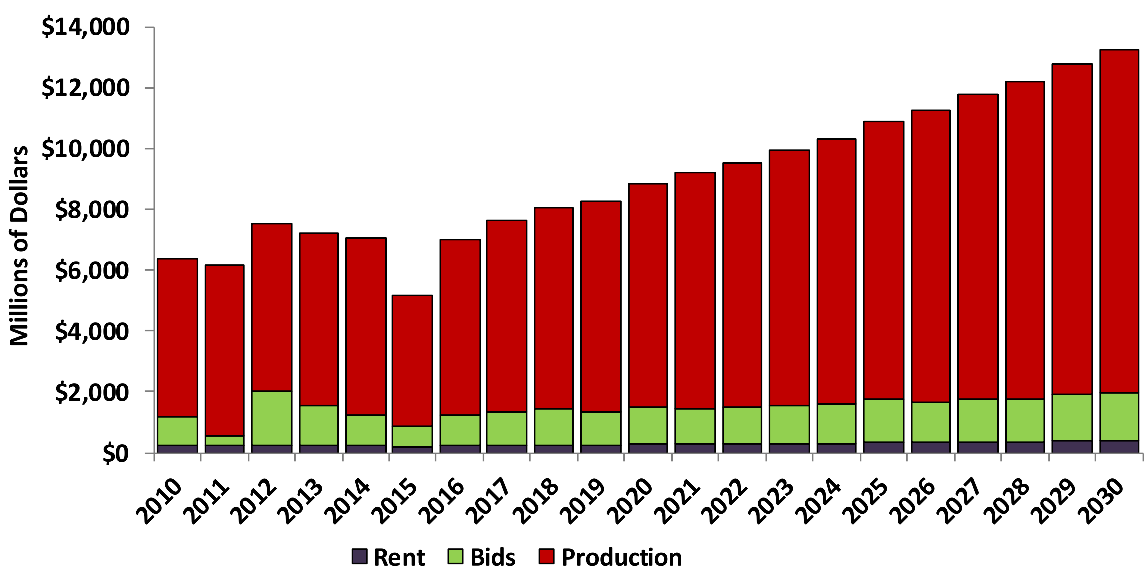
Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$37,332	$36,991	$36,661	$36,948	$37,330	$39,618	$40,400	$40,297	$39,641	$40,141
Proposed Rule	$35,099	$34,186	$33,523	$33,819	$34,297	$35,281	$35,900	$36,851	$35,682	$36,133
Difference	($2,233)	($2,805)	($3,138)	($3,130)	($3,034)	($4,337)	($4,500)	($3,445)	($3,960)	($4,007)

Source: Quest Offshore Resources, Inc.

5.3 Government Revenue

Government revenues due to Gulf of Mexico offshore oil and gas operations are currently collected through three main revenue streams; revenue from lease sales, lease rental rates, and production royalties. The distribution of these revenues streams is heavily skewed towards production royalties, which account for around 80 percent of revenues from offshore oil and natural gas activities. Total government revenues from Gulf of Mexico offshore oil and gas royalties have been between $5 and $8 billion in recent years, lease sale revenues have been between $300 million and $1.5 billion, lease rental revenues have been approximately $200 million per year, and production revenues have provided $5 billion per year. (Figure 18)

Figure 18: Projected Governmental Revenues – Base Development Scenario



Source: Quest Offshore Resources, Inc.

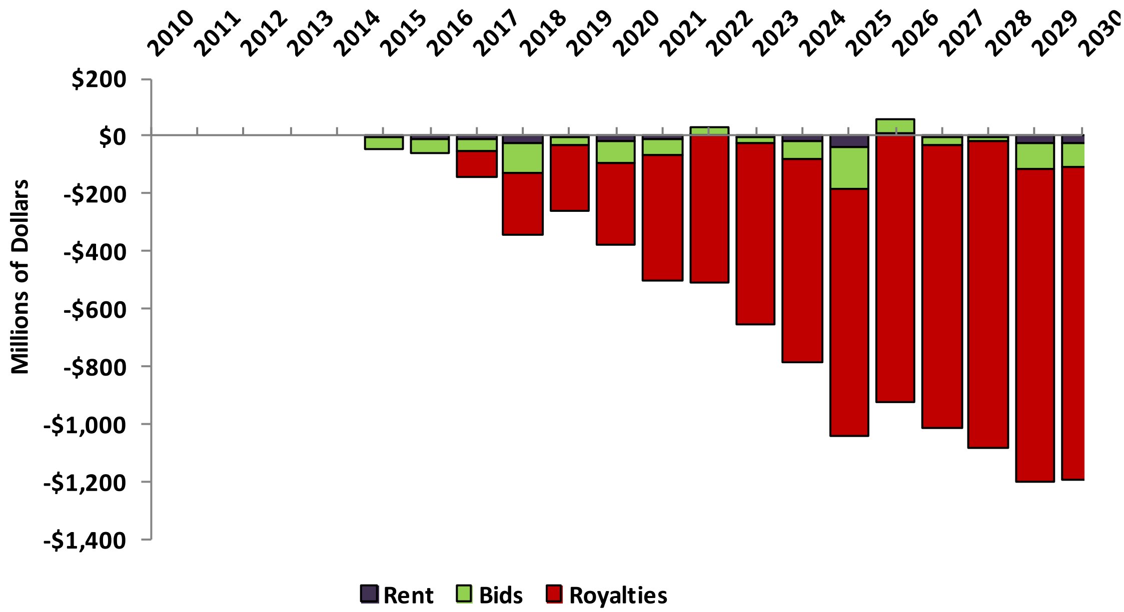
Under the base development scenario, future lease sale levels are expected to remain in line with recent lease sale levels in the region. A minor decrease in the uptake rate due to decreasing lease availability and expected recoverable reserves is projected to leave lease sales relatively flat, ranging from $1 to $1.5 billion each year over the forecast period. Block rentals account for the smallest portion of government revenue and are projected to fluctuate between $200 and $400 million per year over the forecast. Production royalties, calculated using the EIA long term oil and gas price forecast, continue to grow over the forecast due to increasing production, growing from a recent low of $4.2 billion in 2015, driven by low oil prices, to more than $11 billion in 2030. Production royalties will likely increase as projects with royalty rates on more recent leases with high tax rates come on stream throughout the forecast.

State and Federal governments share in the revenue from the GOM oil and natural gas development. Under GOMESA[7] regulations instituted in 2007, state and federal regulators proposed a splitting of offshore revenues between state and federal governments. The second phase of the GOMESA rule will take effect in 2017 which will lead to an approximately a 62.5% to 37.5% split between state and federal governments with revenue capping provisions at $500 million for states.

In parallel with previous section, the effects of the proposed rule are estimated to lead to lower government revenues of around $18.5 billion from 2017 to 2030. Increased costs and lower recovery rates are expected to drive lower lease sales through the period, though growth within leases is expected, with the value of leases sold rising from $650 million in 2015 to $1.5 billion in 2030, while rental rates rise from $180 million to $350 million. The total estimated decline in combined rental and bid revenue due to the proposed rule is approximately $1 billion over the life of the study. Production revenues are expected to rise from 2017 levels even under the proposed rule scenario, especially due to higher oil prices, though the growth is limited in comparison to the base development scenario. Under the proposed rule, revenues rise from $4.3 billion in 2015 to $9 billion in 2030, which is more than $2 billion less than the base case total and represents a drop of nearly 15%. The estimated lost revenue from production royalties will provide the largest portion of potential lost revenues, estimated at around $17.7 billion from 2017 to 2030. The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at $9.9 billion (Figure 19).

[7] Gulf of Mexico Energy Security Act of 2006 (Pub. Law 109-432) – was instituted to update the visibility on leasing activities as well as revenue sharing between state and federal governments.

Figure 19: **Governmental Revenues – Proposed Rule Scenario Difference**



Source: Quest Offshore Resources, Inc.

The revenue effects at the state level are expected to be minimal as GOMESA limits of $500 million per year are reached under both revenue scenarios under Quest's interpretation of the law. (Table 11)

Table 11: **Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 ($Millions)**

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,625	$8,050	$8,262	$8,828
Proposed Rule	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,389	$7,533	$7,746	$8,110
Difference	$0	$0	$0	$0	$0	($0)	($0)	($236)	($517)	($516)	($719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$9,188	$9,518	$9,953	$10,307	$10,909	$11,247	$11,780	$12,222	$12,777	$13,254
Proposed Rule	$8,267	$8,557	$8,740	$8,889	$9,164	$9,580	$9,865	$10,148	$10,488	$10,870
Difference	($921)	($961)	($1,213)	($1,418)	($1,745)	($1,667)	($1,915)	($2,074)	($2,289)	($2,385)

Source: Quest Offshore Resources, Inc.

Section 6 - Conclusions

The oil and gas industry in the Gulf of Mexico has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by supporting well-paying employment for hundreds of thousands of Americans, by providing revenues to many levels of the U.S. government and by contributing to the country's energy needs. The industry has grown into the world leader in offshore safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in now-mature fields, and production has been in decline. Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have led to renewed activity in the Gulf of Mexico OCS, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the economic benefits which it brings. The health of the industry is not, however, guaranteed. A lingering low-price environment and the steadily increasing difficulty and cost of producing oil and gas assets in the Gulf of Mexico have strained project economics and threatened the health of the industry.

While some part of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", are expected to have little or no negative affect on the industry, others will, in their current forms, seriously limit the ability of operators, drilling contractors, and service providers to safely, effectively, and economically operate in U.S. offshore areas, and may make the cost of producing currently economic wells prohibitively high or technically impossible. This decrease in activity and increase in cost will further damage an important industry that is already dealing with the repercussions of a volatile and challenging commodity price environment and may seriously impact the overall U.S. economy.

After analyzing the operational and economic impacts of the regulations, as proposed by BSEE, this study has projected that the following effects will result from their implementation:

- The 10-year costs estimates for the proposed rule from 2017 to 2026 are estimated to be over \$32 billion compared to a BSEE estimate of \$882 million. Most of these costs are attributable to well design requirements and BOP spending.
- When compared to the Base Development Scenario, the decreases in activity caused by these regulations are projected to reduce employment by over 50 thousand jobs as early as 2027 relative to jobs supported under current regulations. This is an estimated decrease of 11% of the projected employment due to the Gulf of Mexico oil and natural gas industry.
- If the proposed rule were to be enacted as currently written, annual capital investment and other spending directly related to offshore oil and natural gas development in the Gulf of Mexico OCS is projected to decrease from \$41.5 billion per year in 2030 to \$36.5 billion per year in 2030.

Cumulative capital investments and other spending from 2017 to 2030 are projected to decrease by nearly $57 billion, a more than 10% drop.

- Between 2017 and 2030, the proposed rule is expected to decrease overall activity significantly in the Gulf, including:
    - A reduction in oil and natural gas production of 0.5 Million Barrels per day or 15.5% (from an average production of 3.10 Million BOE per day to 2.62 Million BOE per day),
    - A 26% decline in the number of wells drilled (from roughly 2,700 to 2,000),
    - 4% fewer leases (Dropping from 6350 to 6100), and
    - 13% less government revenue decreasing from $144 billion to $125 billion (The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at $9.9 billion).
- The effect that domestic offshore oil and gas exploration and production are expected to have on US Gross Domestic Product is expected to be $44 billion lower under the proposed regulations, which is 9% lower than the previous effect. The ten year GDP cost burden of the proposed rule from 2017 to 2026 is estimated at $27 billion.
- It is clear that the proposed rule as currently written will have a significant effect on US employment, GDP, government revenues and domestic energy security due to increased costs borne by industry participants and reduced activity levels.

Section 7 - BSEE Rules & Regulations Appendix

This Report provides an independent high-level review and evaluation of the United States Department of Interior Bureau of Safety and Environmental Enforcement ("BSEE"), proposed rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 (the "Proposed Rule"). The purpose of this Report was to provide a summary of the most impactful sections and subsections of the Proposed Rule. This study is in no way exhaustive - especially in light of the quite short period available to review the Proposed Rule, the highly technical nature of these regulations, and time to develop this analysis with comments.

This Report reviewed key technical effects expected by the Proposed Rule on industry operations, and included those key technical effects within a larger evaluated economic analysis of the Proposed Rule on offshore resource development. The larger economic analysis viewed across stakeholders, including the industry operators, industry support providers (i.e. engineers, designers, manufacturers, service, and equipment suppliers), government revenue losses, and resultant employment effects. The key technical effects were reviewed by Blade Energy Partners, and the economic analyses and evaluation was provided by Quest Offshore Resources.

The analysis in this Report focuses on the likely engineering and operational effects of these regulations, and wherever possible attempts to calculate the cost of overcoming these burdens. As such, this analysis is essentially forward looking, and therefore subject to significant changes based on the final rules as implemented by BSEE, the way in which the final rules are implemented, and a variety of other factors. However, this Report's authors believe that this approach is the best available way to consider this rule (as more a backwards looking review based on previous industry activity would likely overstate the effects of these regulations). Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual rules without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this Report, as well as significant uncertainties about the way the Proposed Rule would be implemented if enacted, the projected costs and engineering and operational burdens for all proposed regulations are not included in this Report. Additionally, the internal costs to BSEE of implementing and administrating the proposed rule are not calculated in this Report. Due to the conservative approach and the time limitations associated with this study it is likely that the full costs and economic impacts presented in this report underestimate the overall impacts of the proposed rule.

The Report's authors make no representation as to the effects of proposed regulations not addressed specifically in this report, and do not discount the possibility that these proposed changes could impose additional significant engineering, operational or other burdens on industry, regulators or others. The Report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering and operations and technology advances are an independent good faith qualitative view arising from unfortunately short considerations by various subject matter persons within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (a consulting company in well design, engineering and operations. If BSEE extends the comment period for the Proposed Rule, then further consideration of the effects the Proposed Rule will have on industry resource development may be requested. The future effects of these Proposed Rule on new, emerging, and likely technologies and methods cannot be evaluated properly within the time frame of this Report effort.

As this was an independent review, industry and others (operators, original equipment manufacturers, support and service providers) may, and surely will have differences of opinion with all or part of this analysis. This analysis was not in any way prepared to contradict or supersede any other view. Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

7.1 General Comments

In general, it is understood that BSEE's Proposed Regulations are attempting to address upstream industry well design and operations perceived gaps or inadequacies. The industry continues to quickly address these topics on its own. Industry well technology is complex, taking time to engineer, develop, and apply for all stakeholders. Even small changes can result in significant ramifications, additional complexities, and costs immediately and in the future. This review strives to identify how BSEE's Proposed Rule will add immediate and future ramifications and added complexities to oil and gas operations on the continental shelf.

Considering the very complex nature of the Gulf of Mexico oil and gas industry, any single Proposed Rule change and the combination of all changes require evaluation by many stakeholders and technology providers.

BSEE's Proposed Rule is expected to have significant current and future effects on well engineering and operations. Industry's ongoing research and development on these topics is continuing, which includes new technologies being deployed currently and in the near to medium future. Much of industry's research and development efforts are focused on the challenges of deepwater drilling in the Gulf of Mexico water with a focus on life of the well, integrity and increasing resource development efficiencies. Research and development also continues in U.S. Government labs and U.S. Government funded projects with universities and others. The fruits of this R&D work will continue to be seen across industry now and beyond - and many are referenced herein. However, it is the opinion of this Report's authors that while some of these proposed regulations will lead to more industry research and development to overcome the burden imposed by these regulations; the prescriptive nature of the proposed rule will likely lead to some current and developing technologies being excluded from offshore oil and gas operations in the Gulf of Mexico.

This Report's authors believe it is positive for all stakeholders that BSEE references recognized developed standards (API, etc.) - as such references are accessible to all stakeholders - whether for U.S. application or globally. However, consideration must be taken as to the evolving nature of industry standards and this should be taken into consideration when writing existing or developing industry standards into proposed rules as this may preclude industry participants from adopting updated industry standards.

Additionally, BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Additionally, the effects of the Proposed Rule requirements needs to be considered if proposed and existing rules are extended to all 'rig' types (including coiled tubing and wireline).

7.2 Analysis of the Proposed Rule

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (a) Lists various compliance and documentation requirements and service fees.

Proposed Regulation Effect on Current Practices: Change will significantly impact well engineering and well operations by adding compliance time to document risk reducing efforts and well construction efforts.

Projected Operational Burden: For well planning, the change will impact well engineering by adding compliance time to document risk reducing efforts and well construction efforts. Including initially, significant compliance cost of around 2 months, including setting up to comply. Once compliance incorporated within a well operator's procedures, the burden should be no more than 2 man-days per individual well plan.

For well operations: The proposed rule adds to the rig management requirements. Initially, these effects could be significant, but once incorporated, the burden should be around 8 man-days per month of operation.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $65.2 million, and an average annual cost $6.5 million from 2017 to 2026.[8]

[8] Cost estimates for each proposed rule subsection are provided based on projected activity levels prior to the adoption of the proposed rule (base case scenario, see Section 2 – Study Methodology for scenario development. Each cost estimate is provided as a 2017 to 2026 total and average annual additional cost to the Gulf Of Mexico OCS oil and natural gas industry as a whole.

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

Proposed Regulation Effect on Current Practices: Said "issued orders" seem to be targeted at operations.

Projected Operational Burden: None; unless the "issued orders" impose a compliance burden, expected to be around 8 man-days per month of operation per facility; or, if an operation is shut down, the burden could be extremely disruptive and costly to the operator.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $61.7 million, and an average annual cost $6.2 million from 2017 to 2026.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)

Proposed Regulation Effect on Current Practices: New requirement that all packers and bridge plugs would have to comply with API Spec. 11D1

Projected Operational Burden: The proposed rule would lead to the loss/scrapping of inventory packers and bridge plugs which do not conform to API Spec. 11D1 manufactured prior to adoption of the rule. It is suggested that the rule adopts a grandfather clause for packers and bridge plugs manufactured prior to the adoption of the rule.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scrapping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (f) Follow all applicable requirements of subpart G; and;

Proposed Regulation Effect on Current Practices: Revised to add reference to the requirements of new Subpart G. This would make Subpart G applicable to decommissioning. The new regulations applying to "all drilling, completion, workover, and decommissioning operations…" The burden for the strict application of these regulations to decommissioning operations needs to be considered. These effects are difficult to estimate.

Projected Operational Burden: Well abandonments are normally considered as part of the plan only for exploration programs and not development programs. At the minimum the burden, applied to development wells, can be estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP plus 3 additional days of operating time plus services, needed to comply with the specified well control regulations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.413 What must my description of well drilling design criteria address?

Proposed Rule: § 250.413 (g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;

Proposed Regulation Effect on Current Practices: This rule would require maximum ECD to the PP/FG/ MW & shoe plot. Additional engineering time will be required.

Projected Operational Burden: This rule would require operators to include fluid modeling and temperature to well planning. The burden should not exceed 4 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $6.9 million, and an average annual cost $690 thousand from 2017 to 2026.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:

Proposed Regulation Effect on Current Practices: The safe drilling margins would also have to meet the following conditions (and was not previously defined): Static downhole mud weight must be greater than estimated pore pressure; Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; The ECD must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; When determining the pore pressure and lowest estimated fracture gradient for a specific interval, related hole behavior must be considered (e.g., pressures, influx/loss of fluids, and fluid types). The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. This section defines mud as the only primary operational barrier allowable. It then goes further to require MW 0.5 ppg below FG and further require ECD to be below FG. This requires mud to be the primary barrier during drilling operations. Precluding the use of MPD, and drilling narrow margin PP/FG wells which is especially relevant in deepwater and ultra-deepwater wells, depleted reservoirs both on the shelf and in deepwater as well in areas with shallow hazards which require casing to be set at relatively shallow depths.

Projected Operational Burden: This proposed rule would likely have a very significant impact on Gulf of Mexico oil and gas activities. Today in the GOM, wells are being designed and operationally planned with BSEE review to use forms of Managed Pressure Drilling (MPD technologies). Globally, wells in shallow water, deepwater, and onshore are and have been drilled successfully using MPD technologies and methods. Existing and new deepwater rigs are being retrofitted or designed as 'MPD' ready rigs. The proposed rule may eliminate drilling narrow margin wells from being drilled. The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. It also does not allow for alternate technologies to replace mud weight as the primary drilling barrier. There are many drilling technologies that allow for a barrier other than drilling fluid during operations. These technologies are employed both onshore and offshore throughout the world. If MPD and drilling with mud weights below .5 PPG is not allowed, many wells in the GOM could not be drilled. If these wells cannot be drilled & completed, then huge deepwater, depleted and other reserves will be undeveloped.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $10.7 billion, and an average annual cost $1.1 billion from 2017 to 2026. This cost was calculated based on estimation of 30 percent of wells requiring additional casing strings, as well around 35 percent of wells lost due to this rule being abandoned while drilling.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

Proposed Regulation Effect on Current Practices: The rule would require operators to include wellhead and liner hanger specifications in the APD.

Projected Operational Burden: Additional information to be provided in the permitting process. The proposed additional requirement will add an engineering burden, estimated at 4-10 man-days per individual well plan regarding well design.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $6.9 million, an average annual cost from 2017 to 2026 of $690 thousand.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (k) Any additional information required by the District Manager.

Proposed Regulation Effect on Current Practices: New paragraph (k) would be added to require submittal of any additional information required by the District Manager. The proposed additional requirement could add a significant engineering burden.

Projected Operational Burden: Will allow for requests of additional information not specified in the CFR. The burden could be as minor as one rig-day per request or as severe as preventing the project from moving forward altogether. A provision for additional information is needed, but there must be a provision for justification (provided by BSEE) and a means for due process appeal (by the Operator). As currently written the rule essentially gives the District Supervisor the power to make requests without limit or justification.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario based on developed for this report is projected at $1.2 billion, an average annual cost from 2017 to 2026 of $113 million based on one request per well and one rig day per request.

Under the main section: § 250.415 What must my casing and cementing programs include?

Proposed Rule: § 250.415 (a) What must my casing and cementing programs include?

(a) The following well design information: (1) Hole sizes; (2) Bit depths (including measured and true vertical depth (TVD)); (3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and (4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

Proposed Regulation Effect on Current Practices: The rule would require the rupture disc information for each casing string (if any).

Projected Operational Burden: The rule would require operators to modify drawings to this information include information, additional engineering time will be required. The burden should not exceed 15 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $25.9 million, an average annual cost from 2017 to 2027 of $2.6 million.

Under the main section: § 250.418 What additional information must I submit with my APD?

Proposed Rule: § 250.418 (g) A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

Proposed Regulation Effect on Current Practices: The proposed rule would likely require a separate approval for well abandonment. The approval would require plan details included in the APD.

Projected Operational Burden: The proposed rule would likely require a more detailed well abandonment plans for casing removal. Additional engineering time will be required. The burden should not exceed 2 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.5 million, and an average annual cost of $345 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (a) (6) Provide adequate centralization to ensure proper cementation; and

Proposed Regulation Effect on Current Practices: Include comments for centralizers and require "adequate centralization".

Projected Operational Burden: Additional time to run the required centralization, when centralizers may not have normally been run. Non Productive Time (NPT) associated with centralizer failures. Together, these can range from no additional time, to a likely estimate of one rig-day per individual well, to weeks of rig time plus services spent fishing centralizers and casing in the event of a catastrophic failure (unlikely). Additional engineering time will be required. The burden should not exceed 3 man-days per individual well plan. Would require documentation that the proposed centralizer program would provide adequate centralization (assumed to be 70% across and above production zones). Would have to attach and perhaps document and/or verify that centralizers are attached to casing.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 billion, an average annual cost $113 million from 2017 to 2026 based on an average of one additional rig day per well drilled.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (b)(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

Proposed Regulation Effect on Current Practices: Minor time requirement to report the needed change. Approval needed for changes to casing design.

Projected Operational Burden: A potential for delay while waiting on a decision from the District Manager. The delay should not exceed 3 rig-days per incident (a full weekend plus one day for review). The impact is expected not to exceed 1 man-day per incident. Changes require approval by District Manager. PE certification is required with submission.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost $173 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (c)(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

Proposed Regulation Effect on Current Practices: Would require the use of a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections. Weighted spacers, designed to avoid going underbalanced during cement placement are a common practice offshore. If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult, requiring a good deal of planning.

Projected Operational Burden: If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult and prone to incurring Non Productive Time (NPT) due to lost circulation. Estimates range from no lost time to the loss of the hole section or entire well, in the event of a serious lost circulation event. An estimate of the additional planning for such a cement job is likely to range between 2 and 10 days per individual well. May affect the cementing operational design but wording in document only requires greater than seawater density of fluid to enhance well bore stability. Operator would have to do proper calculation to insure that this is followed. Would require review during certification process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $983 million, an average annual cost $98 million from 2017 to 2026 based on an average of six engineering days and one rig day per well.

Under the main section: § 250.421 What are the casing and cementing requirements by type of casing string?

Proposed Rule: § 250.421 (b) Conductor ... Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone. Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager

Proposed Regulation Effect on Current Practices: Revised to specify that if oil, gas, or unexpected formation pressure is encountered, the operator would have to set conductor casing immediately and set it above the encountered zone, even if it is before the planned casing point.

Projected Operational Burden: Change to well design and requires permitting and PE certification of design change. Time to secure the well bore and execute the contingency casing option may range between 2 and 7 days of rig time, depending on how much trouble is encountered. The engineering time required to provide a shallow contingency option would add an estimated 2 days to the well engineering process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $440 million, an average annual cost $44 million from 2017 to 2026 based on an assumption of ten percent of wells on average requiring four and a half rig days and two engineering days requiring execution of a contingency casing option after encountering unexpected formation pressure, oil, or gas.

Under the main section: § 250.427 What are the requirements for pressure integrity tests?

Proposed Rule: § 250.427 (b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

Proposed Regulation Effect on Current Practices: As was the case with § 250.414, the proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure.

Projected Operational Burden: If MPD is not allowed, many wells in the GOM could not be drilled. Refer to comments for § 250.414 (c)

Projected Cost of Proposed Rule: Refer to comments for § 250.414 (c)

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations. Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.

Proposed Regulation Effect on Current Practices: District Manager approval is now required if the casing setting depth change is more 100 feet regardless of whether it is deeper or shallower. Require submittal of a professional engineer (PE) certification, certifying that the PE reviewed and approved the proposed changes.

Projected Operational Burden: Statistically speaking, setting pipe shallower than planned is more common than deeper. As such, add an average of 1 day of rig time for waiting per individual well for this occurrence. An additional requirement for PE certification of the change has been added at an expected 3 man-days per well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $195 million, an average annual cost $19.5 million from 2017 to 2026 based on 20 percent of wells requiring a rig day and a 3 man days to receive approval to submit and receive approval to set casing more than 100 feet TVD from the approved APD.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment). (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.

Proposed Regulation Effect on Current Practices: Additional engineering time due to the NPT is expected to be disproportionately higher as depth increases. Revised to clarify requirements concerning what actions must be taken if there is an indication of an inadequate cement job. There are many indicators of an inadequate cement job. These include lost returns, no returns to the mudline or failure to reach the expected height for the specific cement job, cement channeling, abnormal pressures, or failure of equipment. If any of these indicators, or others, are encountered during the cement job, then action must be taken to ensure the cement job is adequate. Such actions may include running a temperature survey, running a cement evaluation log (such as an ultrasonic or equivalent bond log), or a combination of these or other techniques to check cement integrity by verifying the top of cement, density, condition, bond, etc. If the cement job is determined to be adequate, the results of the cement job determination would be submitted to the District Manager in the WAR. Paragraph (c) of the table in this section would be revised to clarify requirements concerning what actions must be taken if there is an indication of an inadequate cement job.

Projected Operational Burden: The change may cause additional NPT due to the new definition for a failed cement job and that the NPT is expected to be disproportionately higher as depth increases. The estimated operational burden is 1 day of rig time per unit of depth squared (measured in thousands of feet) plus the cost of the investigative services. The estimated burden is 1 man-day per unit of depth squared (measured in thousands of feet). Operators would have the burden to review the multiple potential causes for potential inadequate cement job, take action to try to evaluate potential problem, and then make recommendations for and take corrective action.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner. Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

Proposed Regulation Effect on Current Practices: New § 250.428 (k) New requirement for the use of valves while cementing shallow strings. Add clarification concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner, and require the following to assist BSEE in assessing the structural integrity of the well:

—The operator would include a description in the APD of the plan to use a valve that includes a schematic of the valve and height above the water line.

—The valve would be remotely operated and full opening with visual observation while taking returns.

—The person in charge of observing returns would be in communication with the drill floor.

—The operator would record in the daily report and in the WAR if cement returns were observed; and

—If cement returns were not observed, the operator would have to contact the District Manager and obtain approval of proposed plans to locate the top of cement, before continuing with operations.

Projected Operational Burden: The engineering burden is expected to be 1 man-day per well to include the necessary details in the APD or APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost $173 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 What are the source control and containment requirements?

Proposed Regulation Effect on Current Practices: See below.

Projected Operational Burden: See below.

Projected Cost of Proposed Rule: This entry is used for containment system costs, membership, fees and other containment related items not itemized in the following containment related subsection subsections and excludes existing containment equipment. The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.2 billion, an average annual cost $124 million from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.

Proposed Regulation Effect on Current Practices: Requires operators to have access to and ability to deploy Source Control and Containment Equipment (SCCE) as above.

Projected Operational Burden: This is a very costly endeavor and will require a long term industry-wide effort to achieve. In the meantime, operators will need to survey the capabilities of the service community to develop a plan that satisfies the District Manager. Maintain contracts and maintain a fleet of equipment for emergency/ contingency use.

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE–0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.

Proposed Regulation Effect on Current Practices: Requires submittal of a description of the source control and containment capabilities before BSEE would approve an APD. The submittal to the Regional Supervisor would need to include the following: The source control and containment capabilities for controlling and containing a blowout event at the seafloor, and a discussion of the determination required by paragraph (a), and information showing that the operator has access to, and the ability to deploy, all equipment necessary to regain control of the well.

Projected Operational Burden: Once the equipment and capability survey is complete to the satisfaction of the District Manager, then it should only add 1 man-day per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 million, an average annual cost $110 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.

Proposed Regulation Effect on Current Practices: District Manager and Regional Supervisor approval is now required for any well design changes or if any of the approved SCCE is out of service.

Projected Operational Burden: The potential for waiting on approval exists and is estimated at 1 rig-day per event. An engineering effort of 2 man-days per event is estimated.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $195 million, an average annual cost $19.5 million from 2017 to 2026 based on 20 percent of wells facing one rig day and 2 man days of non-productive time while waiting on approval of the district manager due to well designs changes.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (e) You must maintain, test, and inspect the source control and containment equipment identified in the following table according to these requirements: Equipment Requirements, you must: Additional information (1) Capping stacks .... (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests). Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned. (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization. Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves. (iii) Notify BSEE at least 21 days prior to commencing any pressure testing. (2) Production Safety Systems used for flow and capture operations. (i) Meet or exceed the requirements set forth in 30 CFR 50.800–250.808, Subpart H. (ii) Have all equipment unique to containment operations available for inspection at all times. (3) Subsea utility equipment Have all equipment unique to containment operations available for inspection at all times. Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

Proposed Regulation Effect on Current Practices: New inspection and testing requirements.

Projected Operational Burden: (1) Capping Stacks: Estimated at 80 man-days per year per system. (2) Prod. Safety Systems: Estimated at 80 man-days per year per system. (3) SS Utility equip.: No burden expected

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New e) New paragraph (e) would add packer and bridge plug requirements including: Adherence to newly incorporated API Spec. 11D1, Packers and Bridge Plugs; Production packer setting depth t allow for a sufficient column of weighted fluid for hydrostatic control of the well; and Production packer setting depth criteria.

Proposed Regulation Effect on Current Practices: Completions fluids, including gas lifted wells, have clean brine in the A annulus. This rule will preclude gas lift completions because gas lift requires gas filling the A annulus above the operating gas lift valves. The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap.

Projected Operational Burden: The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap. The production tieback casing choices become limited or non-existent with the requirement for kill weight packer fluids hydrostatic control of the well in the A annulus or tubing annulus. Additionally, HPHT wells require very dense fluids to control the well. These fluids are very corrosive at high temperatures.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scrapping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

Proposed Regulation Effect on Current Practices: It may not be possible to set a packer deep enough to have a column of kill weight fluid at the packer.

Projected Operational Burden: If the casing design is suitable for the packer to casing loads, it should not matter if the casing is cemented or not. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 million, an average annual cost $113 thousand. Although the effects of this rule under the proposed rule scenario were not calculated due to the time limitations associated with the study, in cases where it is not possible to set a packer deep enough to have a column of kill weight fluid at the packer the regulation as written would likely lead to the abandonment of otherwise safe and commercial wells.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

Proposed Regulation Effect on Current Practices: Additional engineering time will be required. Sometimes it is not possible to get cement at the packer depth. For instance, where a production packer is set above a production liner top and the well is perforated inside the liner.

Projected Operational Burden: The burden should not exceed 1 man-day per individual well plan. In some cases a well could not completed due to this rule or if a block squeeze job is required to meet the proposed rule requirements.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not be completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New f) Would require, in your APM, a description and calculations of how the production packer setting depth was determined.

Proposed Regulation Effect on Current Practices: Operators would be required to calculate the hydrostatic head of a column of fluid to the packer.

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.619 Tubing and wellhead equipment

Proposed Rule: § 250.619 (f) Your APM must include a description and calculations for how you determined the production packer setting depth

Proposed Regulation Effect on Current Practices: See comments as § 250.518 (New f)

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not too uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic. The additional engineering time should not exceed 1 man-day per individual APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Under the main section: § 250.710 What instructions must be given to personnel engaged in well operations?

Proposed Rule: § 250.710 Prior to engaging in well operations, personnel must be instructed in: (a) Date and time of safety meetings. The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. Date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives. (b) Well control. You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

Proposed Regulation Effect on Current Practices: Additional offshore drills will be required during well operations in critical hole sections (i.e., BHST > 300˚F or MASP > 10,000 psi at the point of control or where H_2S or hydrocarbons are flowing at the surface.

Projected Operational Burden: The burden is estimated at one-half hour per rig-day of operation when applicable. The burden is estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $2.3 billion, an average annual cost $230 million based on one half a rig day per month of non-productive time and around 5 additional engineering days required to meet the increased training requirements.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 What rig unit movements must I report?

Proposed Regulation Effect on Current Practices: This additional regulation will add the time needed to make the required application and it applies to all, but routine, well interventions, regardless of the type.

Projected Operational Burden: Wireline units are included in this regulation as a 'rig movement'. The burden could be estimated by surveying the service industry to get an idea of how many interventions are performed and multiply that number by 1 man-day of operator time plus the application fee, if applicable, needed to make the application. (Presently, Form BSEE-0144 is not listed in the fee schedule but this this study foresees that the increased burden on BSEE to process this additional information will require some cost.)

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE– 0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or (3) The departure of a rig unit from the location.

Proposed Regulation Effect on Current Practices: All equipment movement reported notification time from 24 hrs to 72 hrs. May submit permitting for short operations at the same time for move on/ move off.

Projected Operational Burden: This is cumbersome and expensive for wireline and coiled tubing units. Advance notice of wireline movements or coiled tubing movements could impose an operations burden on operators of these units depending on implementation.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712: What rig unit movements must I report?

Proposed Rule: § 250.712 (e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

Proposed Regulation Effect on Current Practices: Movement of rig prior to arriving in OCS waters.

Projected Operational Burden: Requires an update form based on change in equipment movement by more than 24 hours. This is not limited to rig movement but any equipment movement onto or off of a well.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE–0144, Rig Movement Notification Report.

Proposed Regulation Effect on Current Practices: A new movement form required if the move on/ off location changes by more than 24 hours.

Projected Operational Burden: If reporting requirement leads to a movement delay, costs are increased.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.720 When and how must I secure a well?

Proposed Rule: § 250.720 When and how must I secure a well?

Proposed Regulation Effect on Current Practices: This is related to emergency or contingency operations. While the occurrence of compromised casing integrity can vary widely between operators and well types, a reasonable rate of occurrence for the purpose of this calculation is that one "critical" string in 50 can be expected to become compromised. (A critical string can be defined as one where the BHST > 300˚F or MASP > 10,000 psi at the point of control or where H2S is flowing at the surface.)

Projected Operational Burden: While the mitigation efforts associated with a breach of casing integrity do vary widely, a reasonable estimate of the operational time required mitigate such a breach is 5 rig days per event. In these events, the time needed for the development of a mitigation strategy, then PE review and certification is estimated at 4 man-days per event. None, except for cases where prolonged operations have actually compromised well bore integrity.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (a)**:** You must test each casing string that extends to the wellhead according to the following table…

Proposed Regulation Effect on Current Practices: Changes the requirements for pressure testing casing and liners, increase conductor test pressure from 200 psi to 250 psi., test surface, intermediate, and production to 70% of Minimum Internal Yield, test each drilling liner and liner lap before continuing operations. Requires testing each production liner and liner lap, DM may approve or require additional casing test pressures. If a well would be fully cased and cemented, the operator would have to pressure test the well to the maximum anticipated shut-in tubing pressure before perforating the casing or liner. If a well would be an open-hole completion, the operator would have to pressure test the entire well to the maximum anticipated shut-in tubing pressure before drilling the open-hole section of the well. Requires for a PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test. Requires a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems and outline the requirements for those tests.

Projected Operational Burden: Will require minor changes to pressure testing of BOPs. Presumably, the new requirement for District Manager notification in the event of an interruption of operations will be by telephone call. If a written notification must be made, assume 1/2 man-day per incident as the burden to the operator. Also requires time to pressure test. As well as possible safety risks associated with high pressure testing equipment at surface. Excess internal pressure causes tensile cracks and leak paths in the cement sheath. Inconsistent, and conflicting wording in this rule (requirement to test production casing to 70% test and testing maximum anticipated SITP).

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.

Proposed Regulation Effect on Current Practices: Requires pressure testing the well to maximum anticipated shut in tubing pressure which is excessive.

Projected Operational Burden: Requires additional time to perform these tests is expected to be 1/2 rig-day of operating time per producing well to pressure test. There are risks associated with high surface pressure testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $327 million, an average annual cost $33 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to replacement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

Proposed Regulation Effect on Current Practices: PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test.

Projected Operational Burden: The estimated burden is one man-day per failed pressure test. A reasonable rate of occurrence for the purpose of this calculation is that one test in 40 can be expected to fail. The rig time spent waiting on orders following a failed pressure test, plus the time needed to mitigate and re-test are already being absorbed by the operator. The new requirement for certification is expected to add to this waiting time and is estimated at 1/2 rig-day per event.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $12.2 million, an average annual cost $1.2 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

Proposed Regulation Effect on Current Practices: Requires operators to perform a negative pressure test.

Projected Operational Burden: Additional rig time will be required during well operations to perform the tests. The burden is estimated at 0.5 rig-days per test.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $478 million, an average annual cost $48 million.

Under the main section: § 250.722 What are the requirements for prolonged operations in a well?

Proposed Rule: § 250.722 What are the requirements for prolonged operations in a well? If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:…

Proposed Regulation Effect on Current Practices: Requires operators to perform certain actions if wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner.

Projected Operational Burden: PE certification required if testing shows well below safety factors. Burden is estimated as 1 man-day.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $346 thousand, an average annual cost $35 thousand.

Under the main section: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

Proposed Rule: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow? You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked up over a platform with producing wells or that has other hydrocarbon flow:

Proposed Regulation Effect on Current Practices: Would require the installation of emergency shutdown stations on rig units tied into the production system.

Projected Operational Burden: This will take design and engineering time and new emergency shutdown procedure training for both the rig and platform crews.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.724 What are the real-time monitoring requirements??

Proposed Rule: § 250.724 What are the real-time monitoring requirements?

Proposed Regulation Effect on Current Practices: Presently, only a few of the super-major oil and gas operators have onshore real-time monitoring capability. Under these provisions, the rest of the operators would have to establish a monitoring facility and staff it 24/7, in order to comply. Requires a RTOC for monitoring BOPs, fluid handling and downhole conditions, requires onshore personnel to assist rig crew in monitoring, requires BSEE access upon request, and requires operators to notify DM if monitoring capability is lost.

Additionally, BSEE is considering extend this requirement beyond subsea BOPs, surface BOPs, floating facilities or BOPs operating in an HPHT environment

Projected Operational Burden: This will be a very costly addition to the regulations for most operators. Furthermore, the option for smaller operators to share a common monitoring facility is unlikely due to the sensitive nature of the data. Real Time Monitoring on all well operations, including shallow water shelf operations, will result in significant addition to the sensor, data integration, data telemetry band width, data reception and storage, and data monitoring & interpretation burden for all operators. There is significant uncertainty on the implementation and ongoing cost of these efforts due to the previously limited scale of these types of operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $670 million, an average annual cost $67 million.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Regulation Effect on Current Practices: The proposed additions will serve to limit the number of vendors whose equipment can be used in operations under the regulation of BSEE. There will certainly be a cost associated with the increased consideration given to the design, testing and maintenance of the BOP and its associated systems.

Projected Operational Burden: This regulation should exclude components above the uppermost ram preventer (e.g.. annular and LMRP or riser connect.) Annular preventer does not meet MASP, annulars are available up to 10,000 psi at this time and are not available for 15K, 20K or 25K stacks. Even with this change this may limit the number of contract rigs available to support operations in BSEE regulated waters. There will certainly be a cost associated with the increased consideration given to the operation and testing of the BOP and its associated systems while in service. There also exists the very real possibility that an operation will have to be suspended if a BOP fails to meet the standard and an alternative is not available.

Projected Cost of Proposed Rule: The total effects of this rule as written are impossible to calculate, as written this rule would preclude drilling wells with pressures greater than 10 thousand psi with available technology, these wells account for a significant portion of US OCS activity.

The total cost of the effects of this rule if modified are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a)(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

Proposed Regulation Effect on Current Practices: Would require that pipe and variable bore rams be capable of closing and sealing on drill pipe, workstrings, or tubing under MASP with the proposed regulator settings of the BOP control system.

Projected Operational Burden: The intent of this regulation is unclear. The BOP pressure test indicates if the BOP will seal for MASP or RWP as required. A shear test for on the actual run-in-hole tubing final completion tubing systems cannot be completed, because testing the final completion system will shear and destroy safety valve (SCSSV) and chemical injection or intelligent completion control lines and/or electrical submersible pump (ESP) or downhole sensor or intelligent completion electric cables. Nevertheless, these lines and/or cables are easy to shear (compared to the tubing), and a sample shop stump test tubing w/ lines-cables proves it all.

Projected Cost of Proposed Rule: The costs of this regulation have not been calculated as the shear tests as described in this regulation would be impossible to complete without damaging important well equipment and tubing effecting both the commercial viability and safety of a well. If the suggestion to allow performance of this testing at a test shop is enacted the effects will be minimal.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a) (4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

Proposed Regulation Effect on Current Practices: Paragraph (a) (4) would require a current set of approved schematics to be on the rig and at an onshore location. It would also require that if there are any modifications to the BOP or control system that will change your schematics, operations would be suspended until the operator obtains approval of the new schematics from the District Manager.

Projected Operational Burden: This section seems to imply that the operator would specify, own and maintain BOP system. Also could lead to delays while waiting approval of new BOP schematics.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

Proposed Regulation Effect on Current Practices: Would require that if an operator plans to use a BOP stack manufactured after the effective date of the final rule, the operator must use one manufactured pursuant to API Spec. Q1.

Projected Operational Burden: Compliance effective date set in the Proposed Rule must allow industry time to engineer and design new API Spec. Q1 equipment - and allow time for existing inventory, work in process, and already ordered but not yet manufactured non Spec. Q1 equipment to be grandfathered and worked through.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (a & b) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; You must submit: Including: (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes). (b) Schematic drawings, (1) The inside diameter of the BOP stack, (2) Number and type of preventers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled, including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated valves of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

Proposed Regulation Effect on Current Practices: What information must I submit for BOP systems and system components? The introductory text would reflect that the requirements of BOP description submittals would apply to APDs, APMs, and other required submittals. This introductory text would also clarify that if the operator is not required to resubmit the BOP information in subsequent applications, then the operator must document why the submittal is not required — in other words, the operator would need to reference the previously approved or accepted application or submittal and state that no changes have been made. New requirements for BOP description, new requirement for BOP drawings and labeling on drawings.

Projected Operational Burden: Testing required for BOP operation at specific water depth. An estimated 3 man-days per individual well to prepare the location-specific calculations for submittal.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $330 thousand.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (c) Certification by a BSEE approved verification organization, Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for BOP to shear at water depth, meets the extreme environment conditions and accumulator have sufficient fluid to function without assistance from the charging system.

Projected Operational Burden:

Changes to permitting documents. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (d) Additional certification by a BSEE approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility, Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for additional certification if an operator uses: a subsea BOP, a BOP in an HPHT environment, or a surface BOP on a floating facility. The certification would include verification of the following, the BOP stack is designed for the specific equipment on the rig and for the specific well design, the BOP stack has not been compromised or damaged from previous service; and the BOP stack will operate in the conditions in which it will be used.

Projected Operational Burden: In the short term, there may be limits to the number of qualifying and certifiable BOP systems available for service. BSEE does not want to limit the new requirements only to deepwater or HPHT wells. Additional certification is estimated at 3 man-days to accumulate the documentation plus 1 man-days for the actual certification. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected documentation and verification cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Other costs of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, A listing of the functions with their sequences and timing.

Proposed Regulation Effect on Current Practices: This paragraph would require a listing of the functions with sequences and timing of autoshear, deadman, and emergency disconnect sequence (EDS) systems.

Projected Operational Burden: Additional information provided to the BSEE for BOP certification. Additional time will be required to prepare the documents for submission. The burden is estimated at 3 man-days per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $331 thousand.

Additionally: The BSEE is considering expanding the requirements of this paragraph to all BOPs. The BSEE is specifically soliciting comments on whether this certification requirement should be applied to all well operations, including shallow water shelf operations and operations with surface BOPs.

Proposed Regulation Effect on Current Practices: For some well operations (coiled tubing, and wireline specially) this will be an expensive new requirement. BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Also, the effects of the Proposed Rule requirements need to consider the personnel necessary to cover BSEE's proposed extension to all 'rig' types (including coiled tubing and wireline), and to all shallow water and shelf operations.

Projected Operational Burden: BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.

Proposed Regulation Effect on Current Practices: Adds a certification requirement stating that the Mechanical Integrity Assessment Report required in proposed § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. The items covered under this section have not been routinely submitted to BSEE or obtained by the operators charged with responsibility to maintain well control.

Projected Operational Burden: 'BSEE approved verification organizations' required. Additionally life cycle monitoring of the BOP. This may be possible for new BOPs but difficult for existing BOPs with limited records of well life loads.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 General Overview

Proposed Regulation Effect on Current Practices: In reference to the third-party verification and documentation by a BSEE approved verification organization: The objective is to have this equipment monitored during its entire lifecycle by an independent third-party to verify compliance with BSEE requirements, OEM recommendations, and recognized engineering practices. The list of approved verification organizations would be limited to those that can clearly demonstrate the capability to perform this comprehensive detailed technical analysis.

Projected Operational Burden: BSEE has not yet established criteria of organizations and will need to maintain a list of approved suppliers.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $231 million, an average annual cost $23 million based on each operating rig requiring 30 man days per month of additional engineering time to comply with the sections requirements.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (a) The BSEE will maintain a list of BSEE approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;
2) Technical capabilities;
3) Size and type of organization;
4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;
5) Ability to perform the verification functions for projects considering current commitments;
6) Previous experience with BSEE requirements and procedures; and
7) Any additional information that may be relevant to BSEE's review.

Proposed Regulation Effect on Current Practices: None, if companies can be grandfathered. Otherwise, there will be some time required to apply to be an approved verification company. BSEE will maintain a list of BSEE approved verification organizations, and also outline criteria to become a BSEE approved verification organization.

Projected Operational Burden: The effective date of new regulations requiring a BSEE approved verification organization is too short to have sufficient numbers or verification organizations available for all GOM OCS drilling well operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor. You must submit verification and documentation related to:

1) Shear Testing that:
   i) Demonstrates that the BOP will shear the drill pipe and any electric-,wire-, and slick-line to be used in the well;
   ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;
   iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;
   iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16);
   v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and
   vi) Includes all testing results
2) Pressure integrity testing that:
   i) Shows that testing is conducted immediately after the shearing tests;
   ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and
   iii) Includes all test results.
3) Calculations that
   i) Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP

Proposed Regulation Effect on Current Practices: - This rule is applicable to any operation that requires any type of BOP, and would require verification of shear testing, pressure integrity testing, and calculations for shearing and sealing pressures for all pipe to be used. Each of these verifications must demonstrate the outlined specific requirements.

Projected Operational Burden: This requirement is vague related to HPHT environment and what existing standards are being exceeded. This indicates that the operator, not the equipment owner carries the burden for demonstrating reliability. Added time to perform a shear test is estimated at 20 man-days per ram plus an additional 5 man-days per size, weight & grade of pipe.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $45 million, an average annual cost $4.5 million.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment. The required submissions are:

1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,
2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible, including:
    i) Identification of all reasonable potential modes of failure, and
    ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and
4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.
    i) For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

Proposed Regulation Effect on Current Practices: This regulation would require a comprehensive review by a BSEE approved verification organization of BOP and related equipment being proposed for use in HPHT service. This would require a special verification process for BOP and related equipment being used in HPHT environments because the design conditions required for an HPHT environment exceed the limits of existing engineering standards. Additionally, the use of a BSEE approved verification body would provide BSEE with an additional layer of review and verification at all steps in the development process.

The paragraph makes it clear that the operator has the burden of clearly demonstrating the reliability of the equipment through a comprehensive review of the design, testing, and fabrication process.

Projected Operational Burden: This rule is related to § 250.731 (f), but explains what is required in the report. This will require added time to perform the additional verifications. The reviewer defers estimating this requirement to a BOP expert.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166. This report must include:

1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.
2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.
3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.
4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.
5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.
6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and OEM requirements.
7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.
8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.
10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.
11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.
12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.
13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

Proposed Regulation Effect on Current Practices: The rule would include new requirements on the submission of a Mechanical Integrity Assessment Report on the BOP stack and systems. New paragraph (d) would outline the requirements for this report, which must be completed by a BSEE approved verification organization and submitted by the operator for operations that would require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations.

This rule specifically requires an annual submittal of a Mechanical Integrity Assessment Report for a subsea BOP, a BOP used in HPHT environment, or a surface BOP on a floating facility. This paragraph would outline the requirements of a Mechanical Integrity Assessment report.

Projected Operational Burden: This rule will result in added time to submit the annual assessment. The estimated time required to generate and submit the report is 3 man-days per stack per year.

Projected Cost of Proposed Rule[9]: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.3 million, an average annual cost $130 thousand.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

[9] The projected cost of 250.732 (d) is based solely on the preparing of the verification reports, the cost associated with various inspections and procedures which are required to be verified are listed in the appropriate subsections. The removal or rewriting of those subsections without subsequent modification of the verification requirements could lead to significant increases in the projected cost of this subsection.

Proposed Regulation Effect on Current Practices: This rule will require operators to make all documentation that supports the requirements of this section available to BSEE upon request, and by extension, will require that a third party verify the testing and qualification of BOP equipment to ensure consistent results and provide a reasonable assurance of the performance of this equipment.

The BSEE requests comments on the following issues associated with this section:

- On the issue of standardized test protocols and whether there are any specific procedures that should be considered for adoption.
- On the importance of applying forces in tension or compression during the actual shearing tests.
- On what criteria should be used to qualify a BSEE approved verification organization and whether OEMs should be considered for the program.
- On the issue of updating test protocols and criteria used by verification organizations, given the likelihood of future improvements to BOP technology.

Projected Operational Burden: BSSE requested comments for the section (e) will take a longer than the current comment period to formulate.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 General Overview

Proposed Regulation Effect on Current Practices: This regulations would contain revisions clarifying its applicability to all operations covered under Subpart G. It also adds specific requirements for a surface BOP used in HPHT environments if operations are suspended to make repairs to any part of the BOP system.

The BSEE is requesting comments on requiring dual shear rams for BOPs used in HPHT environments, and how long it would take to comply with the dual shear requirement for BOPs used in HPHT environments."

Projected Operational Burden: Request for comments only.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (b) If you plan to use a surface BOP on a floating production facility you must: (1) Follow the BOP requirements in § 250.734 (a)

1) You must comply with this requirement within 5 years from the publication of the final rule.
2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.
   i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.
   ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.

Proposed Regulation Effect on Current Practices: This regulation would codify BSEE policy and would:

—Clarify that when using a surface BOP on a floating production facility:

   a) the same BOP requirements apply as in § 250.734 (a)(1), and
   b) a dual bore riser configuration would be required for risers installed after the effective date of this rule before drilling or operating in any hole section or interval where hydrocarbons may be exposed to the well;

—Require risers to meet the design requirements of API RP 2RD;

—Clarify that the annulus between the risers must be monitored during operations;

—Require a description of the monitoring plan in the APD or APM, including how you would secure the well if a leak is detected; and

—Clarify that the inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner.

Additionally, API Standard 53 does not impose dual shear requirements for surface BOPs on floating facilities; however, this proposed rule would require dual shears.

Projected Operational Burden: The dual riser requirement may require additional engineering time going forward. Existing production floating facilities must have the room to accept dual bore risers or dual shear BOPs. If not, retrofitting may not be possible. This rule should allow existing and under construction units to be grandfathered in, otherwise the projected cost of the proposed rule would likely be much higher.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated in total, however, while some engineering and construction costs would be expected to design and manufacture new units to comply with these rules the effect on existing units would likely be orders of magnitude greater if a provision to grandfather in existing units is not inserted. As an example, newly installed or soon to be installed dry tree floating production units for some multi-billion dollar projects may be unable to drill and complete new wells if they could not be modified to meet the new requirement. This would likely lead to a 10 to 20 year reduction in the life of these fields and a loss of a majority of the investment into these projects.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (e) You must install hydraulically operated locks.

Proposed Regulation Effect on Current Practices: This regulation would require the replacement of manual locks with hydraulically operated locks for surface BOPs.

Projected Operational Burden: Depending on the implementation timing of the requirement manufacturing, deliver, and installation of this equipment could lead to out of service time for drilling rigs with surface BOPs. Additionally, this requirement is unnecessary as manual locks on surface BOPS are always accessible.

Projected Cost of Proposed Rule: The projected cost of this rule under the base development scenario from 2017 to 2026 is $5.5 million or $550 thousand a year on average based on average replacement cost per surface BOP of around $250 thousand.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and
2) Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: The dual shear requirement could present an issue for rigs where stack space is already limited.

Projected Operational Burden: Repair conditions will impact operations, requiring the rig to stand by until the repairs are complete or a replacement stack can be acquired. In either event, an estimate of 5 to 10 rig-days seems appropriate, per failure that requires a repair.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a) (1) When operating with a subsea BOP system, you must have at least five remote-controlled, hydraulically operated BOPs. You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. Additionally:

(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

Proposed Regulation Effect on Current Practices: The dual shear ram requirement is a very challenging requirement, with the need to be able to cut pipe and coiled tubing and wire while still being able to seal. If put into effect, it will

- Require operators to install a gas bleed line with two valves for the annular preventer.

- Necessitate that each annular has a gas bleed line if annulars were installed on both the LMRP and lower BOP stack

- Demand that the two valves would be able to hold pressure from both directions.

- Require a new device for centering drill pipe that is not one of the BOPs

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. The added requirements for accumulator capacity & redundancy, ROV intervention, emergency shut down, the use of acoustics, side outlet requirements, gas bleed capability below annulars, pipe positioning requirements, pipe compression mitigation and sub-sea battery monitoring will all contribute to significant amounts of engineering effort for new sub-sea BOP stacks.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(1)(ii) The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP.

Proposed Regulation Effect on Current Practices: The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire- , slick-line in the hole under MASP.

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. Adoption of this requirement will require development of new rams that can shear tubing, wireline, etc.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(3) When operating with a subsea BOP system, you must have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. Additionally, the accumulator capacity must:

(i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP.
(ii) Have the capability of delivering fluid to each ROV function i.e., flying leads.
(iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems.
(iv) Perform under MASP conditions as defined for the operation

Proposed Regulation Effect on Current Practices: Generally conforms with API 53.

Projected Operational Burden: Minor modifications to hydraulic system and accumulators.

Projected Cost of Proposed Rule: The estimated cost of modifying BOPs is around $150 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(4) When operating with a subsea BOP system, you must have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability. Additionally, 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).

Proposed Regulation Effect on Current Practices: The proposed rule will increase potential leak paths by requiring an increased requirement for ROV stabs and require minor modification of existing BOP units.

Projected Operational Burden: As written the rule will lead to increased maintenance costs and time, as well as increasing the difficulty of other BOP maintenance. Will also require modifications to existing BOPs including addition of high flow stabs and valves.

Projected Cost of Proposed Rule: The estimated cost of modifying existing BOPs is around $350 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(5) When operating with a subsea BOP system, you must maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations. Additionally, the crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

Proposed Regulation Effect on Current Practices: This rule will require communication between the ROV crew and the rig personnel familiar with the BOP.

Projected Operational Burden: Will require additional training and ROV operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734: What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(6) When operating with a subsea BOP system, you must provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs. Additionally, in reference to the above rule:

(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.

(ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.

(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.

(iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.

(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.

Proposed Regulation Effect on Current Practices: This paragraph would require each emergency function to include both shear rams closing under MASP. The sequencing of each emergency function would have to provide for the lower shear ram beginning closure before the upper shear ram would begin closure. The control system for the emergency functions would be required to be a failsafe design, and each step in the logic would have to be independent of the previous step being completed.

Projected Operational Burden: Will require modifications to the control systems of BOP For safety reasons emergency disconnect sequences must disconnect in the shortest possible time, the sequencing of the shear rams will delay disconnect.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition of timing circuits is estimated at $100 thousand per BOP excluding additional hydraulic tubing and engineering which will be dependent on the specific design of a BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(15) When operating with a subsea BOP system, you must install a gas bleed line with two valves for the annular preventer with the following requirements:

(i) The valves must hold pressure from both directions;

(ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular

Proposed Regulation Effect on Current Practices: The proposed rule requires operators to install a gas bleed line with two valves for the second annular preventer if one is in the LMRP and one in the lower BOP stack.

Projected Operational Burden: This regulation would lead to a significant requirement to modify the stack framework and to purchase suitable annular BOPs to allow the installation of a lower gas bleed line. Immediate implementation of this rule would likely lead to a significant slowdown in drilling from rigs with subsea BOPs due to the time required to manufacture and install components that comply with this rule.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition suitable annular is estimated at $2 million per BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(16) When operating with a subsea BOP system, you must use a BOP system that has the following mechanisms and capabilities:

(i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule;

(ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;

(iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

Proposed Regulation Effect on Current Practices: This regulation requires the installation of a vertical positioning system to position the entire pipe within in the shearing blade. These positioning systems are currently not available. The requirement will also require the installation of a position indicator for each ram BOP, wellhead connector, and LMRP connector that is viewable by the ROV. This would require sensing and displaying pressure within the BOP that is viewable by the ROV.

Projected Operational Burden: Addition of positioning system will likely require significant modification of BOPs, the extent of which is difficult to ascertain prior to the development of these systems. Additional costs associated with modification of control systems are likely.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

1. Submit a revised permit with a verification report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service;
2. Perform a new BOP test in accordance with § 250.737 and § 250.738 upon relatch including deadman and ROV intervention; and
3. Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: Require that if operations are suspended to make repairs to the BOP, operations would have to be stopped at a safe downhole location, submit a revised permit with a report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service, perform a new BOP test upon relatch and receive approval from the District Manager.

Projected Operational Burden: This rule would require a minimum of 1 rig day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $48 million, an average annual cost $4.7 million based on five percent of wells requiring submission of the required information and waiting on approval.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

Proposed Regulation Effect on Current Practices: Additions to this section would provide that if an operator plans to drill a new well with a subsea BOP, the operator does not need to submit with its APD the verifications required by this subpart for the open water drilling operation. However, before drilling out the surface casing, the operator would be required to submit for approval a revised APD, including the third-party verifications required in this subpart.

Projected Operational Burden: This rule would require a minimum of one (1) man-day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $330,000.

Under the main section: § 250.735 What associated systems and related equipment must all BOP systems include?

Proposed Rule: § 250.735 (a) A BOP system must include a surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost.

Proposed Regulation Effect on Current Practices: This rule clarifies that the requirements are for a surface accumulator system, that the system would have to operate all BOP functions, including shearing pipe and sealing the well against MASP without assistance from a charging system; and that these provisions would apply to all BOP systems, not just surface BOP stacks.

Projected Operational Burden: This would require additional tanks, accumulators and pumps to be installed on affected drilling rigs. The ease of the addition of this equipment will be highly affected by the availability of usable deck space in appropriate areas on a given drilling rig.

Projected Cost of Proposed Rule: Cost is estimated at a minimum of $500 thousand per drilling rig if no major structural modification are needed. If major structural modifications are needed costs would be expected to be significantly higher. Due to the time limits associated with this study the costs excluding possible modifications to rig structures under the base development scenario are projected at $48 million total from 2017 to 2026, an annual average of around $4.8 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d) Additional test requirements. You must meet the following additional BOP testing requirements: [§ 250.737 (d)(1)-(12)]

Proposed Regulation Effect on Current Practices: This list of additional rules will lead to new ROV requirements which will mean an extra effort for the ROV service provider until the fleet is wholly compatible. The expanded function testing requirements for the auto-shear, deadman and EDS will add considerable time to the APD & APM submittal effort for subsea operations.

Projected Operational Burden: The reviewer has deferred an estimate for this effort to the ROV service provider, but the expanded function testing requirements for the auto-shear, deadman and EDS are expected to add 0.5 rig-days to the sub-surface BOP test procedures.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $237 million, an average annual cost $23.7 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(5) You must alternate tests between control stations and pods. Additionally:

i) For two complete BOP control stations:
   a) You must designate a primary and secondary station, and both stations must be function-tested weekly,
   b) The control station used for the pressure test must be alternated between pressure tests, and
   c) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests.

ii) Any additional control stations must be function tested every 14 days.

Proposed Regulation Effect on Current Practices: This rule expands testing requirements for two BOP control stations. The operator would be required to designate the control stations as primary and secondary and function-test each station weekly. The control station used to perform the pressure test would be required to be alternated between each pressure test. For a subsea BOP, the operator would be required to rotate the pods between each control station during the weekly function tests and alternate the pod used for pressure testing between each pressure test. If additional control stations are installed, they would have to be tested every 14 days.

Projected Operational Burden: This rule requires at least 15 min per function test for each additional control station. If additional control stations (beyond the minimum of two) are installed, they would have to be tested every 14 days.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(12) You must test and verify closure capability of all ROV intervention functions on your subsea BOP. In addition:

(i) Each ROV must be fully compatible with the BOP stack ROV intervention panels.

(ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval.

(iii) You must document all your test results and make them available to BSEE upon request.

Proposed Regulation Effect on Current Practices: These new provisions include requirements that:

—Each ROV must be fully compatible with the BOP stack ROV intervention panels;

—Operators must submit test procedures, including how they will test each ROV intervention function;

—Operators must document all test results and make them available to BSEE upon request.

Projected Operational Burden: These regulations will require additional documentation which will take 15 minutes of engineer time per ROV testing.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(13) You must function test the autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor. Additionally:

(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.

(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.

(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.

(iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.

(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

Proposed Regulation Effect on Current Practices: The test procedures must be submitted for District Manager approval and the proposed rule would require that the procedures include:

—Schematics of the circuitry of the system that would be used during an autoshear or deadman event;

—The approved schematics of the BOP control system with the actions and sequence of events that would take place; and

—How the ROV would be used during the well-control operations.

During the initial test of the deadman system, the operator would need to have the ability to quickly disconnect the LMRP. The operators would also have to submit the quick-disconnect procedures with the deadman test procedures in the APD or APM. The operator would have to include in its procedure a description of how it plans to verify closure of a casing shear ram if installed. All test results would have to be documented and submitted to BSEE upon request.

Projected Operational Burden: If the rule allows simulated testing of the deadman switch the operational burden is expected to be minimal.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the unclear intent of the proposed rule as noted above.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (b) If you need to repair, replace, or reconfigure a surface or subsea BOP system; (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE approved verification organization to the District Manager certifying that the BOP is fit for service.

Proposed Regulation Effect on Current Practices: This regulation requires that the operator receive approval from the District Manager prior to resuming operations after replacing, repairing, or reconfiguring the BOP system. To obtain approval, the operator would have to submit a report from a BSEE approved verification organization attesting that the BOP system is fit for service. Any repair or replacement parts would have to be manufactured under a quality assurance program and would have to meet or exceed the performance of the original part produced by the OEM.

Projected Operational Burden: The expected rig down-time associated with the BOP repairs should be fully captured under § 250.733 (f).

Projected Cost of Proposed Rule: Not currently calculated [See § 250.733(f)]

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (j) If you encounter a situation where the need to remove the BOP stack arises, you must have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.

Proposed Regulation Effect on Current Practices: This regulation will require that, after pipe or casing is sheared either intentionally or unintentionally, the operator would have to retrieve, inspect, and test the BOP as well as submit a report to the District Manager from a BSEE approved verification body, stating that the BOP is fit to return to service. Additionally, the subsea stack must be pulled and inspected by a BSEE approved verification company who then must submit a report stating that the BOP is fit to be returned to service following any shearing event. The report should be able to be prepared while the stack is being re-run, assuming the inspection was satisfactory.

Projected Operational Burden: None, as the rig time associated with pulling, inspecting, re-running and testing the sub-surface BOP stack is already a requirement.

Projected Cost of Proposed Rule: Due to the lack of expected operational burdens, there has not been an associated cost calculated for this regulation.

Under the main section: § 250.738: What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (o) If you install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines), you must comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.

Proposed Regulation Effect on Current Practices: This rule adds new requirements applicable to redundant well-control components in BOP systems that are in addition to components required in Subpart G. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes.

Projected Operational Burden: The associated time burden of waiting on approval following the failure of a redundant BOP system is estimated at 1 rig-day per event. Failure of a redundant component will require a report to be submitted to the District Manager, estimated to be one man-day's effort per failed BOP test.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $48 million, an average annual cost $4.8 million based on five percent of wells encountering a failure of a redundant BOP system.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (p) If you need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations, you must ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

Proposed Regulation Effect on Current Practices: This rule will result in new requirements that operators would have to meet if they need to position the bottom hole assembly across the BOP for tripping or any other operations, including:

—Ensuring that the well is stable at least 30 minutes before positioning the bottom hole assembly across the BOP, and

—Including in the well-control plan (required by proposed § 250.710(b)) procedures for immediately removing the bottom hole assembly from across the BOP in the event of a well control or emergency situation before exceeding MASP conditions.

Projected Operational Burden: If this situation arises, the rig must wait at least 30 minutes to prove well stability.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.739 What are the BOP maintenance and inspection requirements?

Proposed Rule: § 250.739 (b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.

Proposed Regulation Effect on Current Practices: This new requirement details the procedures for a complete breakdown and inspection of the BOP and every associated component (which is undefined) which rig owners would be required to undertake every 5 years. This paragraph would also clarify that the complete breakdown and inspection may not be performed in phased intervals. BSEE approved verification organization would have to be present documenting the inspection and any problems encountered and produce a detailed report. The requirement for a complete tear-down & inspection every five years will require considerable manpower on the part of the manufacturer and the BSEE approved verification organization.

Projected Operational Burden: The rig time required to swap BOP stacks is estimated at 80 rig-days every five years, plus the cost to remove tear-down, rebuilt, retest, and reinspect the BOP. This would be based on rig owners purchasing additional rig specific BOPs prior to the five year inspection which can then be reused to reduce downtime. Additional burdens associated with this rule are likely due to the limited infrastructure associated with this type of inspection including a lack of shore based OEM facilities, cranes to remove BOPs at US shipyards, and appropriate testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $8.9 billion, an average annual cost $895 million. This is cost is based on $40 million per additional BOP as a one off cost, and $15 million of inspection and yard costs and 80 days of downtime every five years for each active rig utilizing a subsea BOP.

Under the main section: § 250.743 What are the well activity reporting requirements?

Proposed Rule: § 250.743 (c) The Well Activity Report (WAR) must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

Proposed Regulation Effect on Current Practices: This regulation will require a report describing the operations conducted, any abnormal or significant events that affect the permitted operation, verbal approvals, the wells as-built drawings, casing fluid weights, shoe tests, test pressures at surface conditions, and status of the well at the end of the reporting period. The final WAR would include the date operations finished.

Projected Operational Burden: Properly completing these forms is estimated to require two hours of time from each engineer working on each well.

Projected Cost of Proposed Rule: The total cost for the studied period under the base development scenario developed for this report is projected at $443 thousand, an average annual cost $43 thousand.

Under the main section: § 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

Proposed Rule: 250.746 (e) Requires that the company identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue.

Proposed Regulation Effect on Current Practices: Clarifies that any irregularity that is identified during BOP system testing must be identified on the daily report, any leaks observed during testing or observed from the control station are considered irregularities and would have to be reported to BSEE. Operations would have to be suspended until BSEE grants approval to continue after irregularities.

Projected Operational Burden: One rig day per irregularity of any type, though possibly longer if irregularities are serious. Some irregularities are very minor and should not have to be reported or await approval to continue.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $123.8 million, an average annual cost $12.4 million based on the assumption that ten percent of wells on average may encounter an irregularity requiring one day of non-productive time while waiting on the district manager.

7.3 Other Cost Items

Packer and Bridge Plug Inventory Loss

The following regulations [§ 250.1703 (b), § 250.518 (New e)] are expected to lead to a loss of already manufactured and held in inventory packers and bridge plugs that fail to meet the specifications required by the new rule. The cost of this inventory was calculated by estimating the number of packers and bridge plugs required on a per well basis and under the assumption that one and a half years' worth of inventory is held by various suppliers and operators. The introduction of a grandfathering provision for packers and bridge plugs manufacturer prior to the adoption of this rule would remove this expected cost of the proposed rule. The total cost for replacement of inventory packers and bridge plugs under the base development scenario developed for this report is projected at $32 million, an average annual cost $3.2 million.

BOP Replacement

The following regulations [§ 250.730, § 250.730 (d), § 250.734 (a)(1), § 250.734 (a)(1)(ii), § 250.734 (a)(3), § 250.734 (a)(4), § 250.734 (a)(6), § 250.734 (a)(15), § 250.734 (a)(16)] are expected to lead to the replacement of subsea blow out preventers in the US OCS. The accumulation of these regulations is projected to lead to the inability to economically modify existing subsea blow out preventers for use in the US OCS, leading to the replacement of these BOPs. Any modification costs listed above are solely for indicative purposes in the event of a limited adoption of the proposed rule as written and are not included in the cumulative costs in this study. The total projected cost of replacing subsea BOPs for use in the Gulf of Mexico OCS is projected at around $2.1 billion from 2017 to 2026 and annual average of around $210 million over the same period.

BSEE Approved Verification Organizations

BSEE Approved Verification Organizations (BAVO) are not defined by the regulations [§ 250.731 (c), § 250.731 (d), § 250.732 (a), § 250.732 (c), § 250.732 (e), § 250.733] and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or the possible effects that delays in defining and approving these organizations may impose.

Section 8 - Extended Methodology Appendix

8.1 General Methodology

Quest's methodology focused on constructing a tiered "bottom-up" model that separated the complete life cycle of offshore operations and subsequent effects into four main categories – these categories are further developed into cases and presented as the Base Development scenario and Proposed Rule scenario within the paper. The four main categories are as follows;

- A "Rule" model that independently assesses the individual or combined effects of the proposed rules within "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control"
- An "Activity Forecast" model assessing Quest's project database and project modeling information under which the number of expected projects is developed
- A "Spending" model based on the requirements of developing projects within the "Activity Forecast"
- An "Economic" model focusing on the economic impact on employment and government revenue from the "Spending" model.

Three (Activity Forecast, Spending, and Economic models) of the four individual subsections were further split into five additional criteria that create an individual "Project" model. These categories include; seismic, leasing activity, drilling, infrastructure & project development, and production & operation. (Table 12)

Table 12: Oil and Gas Project Development Model – Aspects of Additional Criteria Included by Model

	Activity Forecast	Spending Model	Economic Model
Seismic	• Pre-Lease Seismic • Leased Block Seismic • Shoot Type	• Cost per acre	• Economic Activity due to seismic spending within states
Leasing	• Yearly lease sales for individual regions	• Bonus bid prices • Rental rate	• Federal and state revenues created through lease sales • Economic activity due to increased state/personal spending
Drilling	• Number of wells drilled • Water depth of wells drilled • Number of drilling rigs required	• Cost per well	• Economic activity due to activity within states
Project Development & Operation	• Project size • Project development time	• Spending per project • Per project spending timeline	• Division of state spending • Economic activity due to project development within states vicinity
Production	• Production type and amount	• Oil and gas price forecast	• Federal and state revenues created by royalty sharing • Economic activity due to increased states/personal spending

Source: Quest Offshore Resources, Inc.

In order to estimate the economic effects and project activity losses through the "Project" model, additional analysis was undertaken to understand which projects would be disrupted through the inability to discover and develop the reserves. This was presented through additional analysis of the Base Development scenario and is provided as the Proposed Rule scenario.

8.2 Rule Costing Methodology

The analysis of spending related to proposed "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" was undertaken through the individual analysis of each rule, while also considering the accretive effects of multiple rules placed upon similar equipment, tasks, and future opportunities. The cost of the proposed rule changes were analyzed on either the basis of time required to complete each activity or the replacement cost of equipment where applicable. Equipment costs were calculated using actual or estimated replacement costs depending on the availably of information. All costs are attempted to be calculated on the basis of the most economic reasonable method to overcome the burden imposed by the regulation. General assumptions used within the modeling are as followed:

- Engineering rate (daily) : $923[10]
- Drilling rate (daily) including spread costs[11]: $800 thousand for deepwater drilling, $250 thousand for shallow water drilling.

The determination of any further costs incurred through the loss of productivity within the region was undertaken through the application of the calculated costs and burdens of rules onto Quest's project and well forecast developed for this study from Quest's proprietary databases. The total cost of the rule was calculated through the combination of reanalyzing Quest's "Project", "Activity", "Spending", and "Economic" forecasts with the additional cost of the rule changes. The difference between the two cases, from a spending, economic, and regulatory perspective provide the total estimated "cost" of the rule.

8.3 Project Development Methodology

In order to account for both currently active projects within the Gulf of Mexico and longer-term prospects that will be developed towards the end of the forecast period into the study's project development activity, Quest incorporated two models into the project development forecast. The near-term activity was developed on known projects or prospects currently under consideration for development, while a longer term forecast was developed on top of the near-term forecast through the analysis of oil prices, leasing trends, development trends, historic project sizes and other relevant factors

The forecast of near term projects utilized Quest's Gulf of Mexico project database that encompasses all major portions of offshore field development (e.g. exploration, number of wells, length of pipelines, size of FPS unit, installation vessels, etc.). In addition to that information, lead times for project development, sanctioning trends and additional spending information led to the expected timeline

[10] Based on the most recent Society of Petroleum Engineers Salary Survey and estimates of total compensation costs.
[11] Based on current day rate and spread (additional drilling) costs from Quest Offshore Data.

and development costs of individual projects. The summation of these costs and timelines over all of the forecasted individual projects provided the total cost of near term projects.

Longer term projects were developed under a less independent methodology for individual projects. In the place of the project-specific spending model, Quest applied historical and current trends within the region to future developments (e.g. a greater focus on deep water oil projects as well as infield drilling and subsea infrastructure) in order to apply the proper costs and timelines to the expected activity. Projects were still delineated by individual timelines and the development scenarios that may be expected of future activity within the region, but were calculated using assumptions on industry trends in production methods instead of on confirmed aspects of the specific projects.

With regards to the Proposed Rule scenario, projects were examined for potential hurdles that would be encountered under the new regulations through several criteria identified from Quest and Blade's research. These topics were focused on emerging trends such as HPHT reservoirs, ultra-deep wells, projects developing already depleted reservoirs, as well as increased project costs. These identified factors drove the forecasted possibility of delays or lost activity due to project economics, technology-driven hurdles, or regulatory impasses. Furthermore, where necessary, additional costs were administered to subsections of projects where increased costs were to be expected for calculations in the economic model.

8.4 Project Spending Methodology

This spending analysis accounts for all capital investment and operational spending through the entire "life cycle" of operations. Every offshore oil or natural gas project must go through a series of steps in order to be developed. Initial expenditures necessary to identify targets and estimate the potential recoverable resources in place include seismic surveys (G&G) and the drilling and evaluation of exploration & appraisal (E&A) wells. For projects that are commercially viable, the full range of above-surface and below-water (subsea) equipment must be designed and purchased. Offshore equipment includes production platforms and on-site processing facilities, as well as below-water equipment generally referred to as SURF (Subsea, Umbilicals, Risers and Flowlines). Finally, the equipment must be installed and additional development wells must be drilled. Once under production, further operational expenditures (OPEX) are required to perform ongoing maintenance, production operations and other life extension activities as necessary for continued field production and optimization.

Spending for individual projects was subdivided into sixteen categories covering the complete life cycle of a single offshore project, as well as two additional groups for natural gas processing and operation. Timing and cost for individual categories were assigned based on the previously mentioned project types where prices are scaled according to the complexity and size of the project. (Table 13)

Table 13: Oil and Gas Project Spending Model

	Activity Model	Spending Model	Economic Model
Seismic (G&G)	• Number of leases • 2D vs. 3D	• Cost per acre	• Operation requirements
SURF	• Trees, manifolds, and other subsea equipment • Umbilicals • Pipelines, flowlines, and risers	• Cost per item • Cost per mile	• Fabrication locations
Platforms	• Fixed Platforms • Floating Production System	• Unit size	• Fabrication locations
Installation	• Surf Installation • Platform Installation	• Number of vessels • Type of vessels • Vessel dayrate	• Operation requirements • Shorebase locations
Drilling	• Exploration drilling • Development drilling	• Rig type • Rig dayrate	• Operating requirements • Shorebase locations
Engineering	• FEED	• CAPEX • OPEX	• Technological centers
Operating Expenditures (OPEX)	• Supply and personnel requirements • Project maintenance • Project reconfiguration	• Type of project and associated infrastructure	• Shorebase locations

Source: Quest Offshore Resources, Inc.

Upon compiling the scenario of overall spending estimates, Quest deconstructed the "local content" of oil and gas operations within the studied region. Individual tasks were analyzed on a component-by-component basis to provide an estimate of the percentage of regional, national, and international construction required by offshore operations. Additionally, delineations were made at the regional level in order to project spending for individual states. Considerations were based on current oil and gas development, the proximity to reserves and production, strategic locations such as shore bases and ports, as well as Bureau of Economic Analysis (BEA) data pertaining to each state's present economic distribution.

8.5 Economic Methodology

The study's GDP and job data were calculated using the BEA's RIMs II Model providing an input-output multiplier on spending at the industry and state levels for each defined category. Model outputs considered from spending effects include number of jobs and GDP multiplier effects. Further delineation is presented in the form of direct and indirect and induced job numbers, which encompass the number of jobs relating to the spending in that category versus indirect and induced jobs that are created from pass-through spending. For states considered within the study that contained no RIMs II multipliers for specific sectors, state multiplier from economies that most closely paralleled those in question were replicated.

Rims Categories used:

- Architectural, Engineering, and Related Services
- Construction
- Drilling Oil and Gas Wells
- Fabricated Metal Product Manufacturing

- Mining and Oil and Gas Field Machinery Manufacturing
- Oil and Gas Extraction
- Steel Product Manufacturing from Purchased Steel
- Support Activities for Oil and Gas Operations

8.6 Governmental Revenue Development

Governmental revenue data is presented in three categories; bonus bids from lease sales, rents from purchased but not yet developed leases, and royalty payments from producing leases. The projected revenue was calculated under the assumption that the current operating structure of the Gulf of Mexico would remain in place where applicable. Lease sales and rental rates were calculated through the simulation of yearly lease sales within each individual area, while the number of leases acquired was modeled on oil price forecasts, historical rates, and on the estimated amount of reserves in the western and central OCS regions.

The federal / state government revenue split of leases, rents and royalties were modeled under the application of GOMESA (Gulf of Mexico Energy Security Act). As Quest understands the rule and phase II beginning in 2017, GOMESA regulations would effectively split 37.5 percent of OCS bonus bid, rent, and royalty income between the appropriate states. GOMESA has an annual revenue cap of $500 million for the Gulf States.

Production pricing were calculated using the EIA estimates for both West Texas Intermediate (WTI) spot and Henry Hub natural gas prices[12]. Additional governmental revenues such as income and corporate taxes were considered outside of the scope of this study, and are likely to provide additional government revenues throughout the studied period.

[12] United States. Energy Information Administration. *Annual Energy Outlook 2015*. Energy Information Administration, 14 April 2015.

Section 9 – Additional Tables Appendix

Table 14: Annual Compliance Costs by Affected Activity or Equipment – Proposed Rule Scenario ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	$822	$856	$1,246	$1,223	$1,184	$1,225	$1,163
Compliance and Documentation	$9	$11	$10	$10	$11	$10	$10
Containment	$112	$113	$177	$177	$186	$83	$82
Rig Requirements	$175	$186	$181	$185	$186	$176	$171
Real Time Monitoring (RTM)	$69	$69	$71	$63	$55	$50	$46
Tubing and Wellhead Equipment	$33	$0	$1	$1	$1	$0	$0
Well Design	$1,441	$1,205	$1,312	$1,395	$1,380	$1,387	$1,243
Grand Total	**$2,661**	**$2,441**	**$2,997**	**$3,055**	**$3,003**	**$2,931**	**$2,715**

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	$712	$752	$823	$918	$1,038	$914	$851
Compliance and Documentation	$10	$9	$12	$11	$13	$12	$14
Containment	$82	$83	$83	$74	$77	$78	$79
Rig Requirements	$171	$171	$191	$205	$225	$224	$225
Real Time Monitoring (RTM)	$47	$48	$47	$40	$54	$83	$61
Tubing and Wellhead Equipment	$0	$0	$1	$1	$1	$1	$1
Well Design	$1,112	$1,253	$1,427	$1,547	$1,741	$1,901	$1,943
Grand Total	**$2,135**	**$2,317**	**$2,584**	**$2,795**	**$3,148**	**$3,212**	**$3,175**

Source: Quest Offshore Resources, Inc.

Table 15: Annual Compliance Costs by Affected Activity or Equipment – Base Development Scenario ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14
Containment	$113	$114	$179	$181	$190	$99	$97
Rig Requirements	$204	$205	$205	$215	$239	$239	$240
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56
Tubing and Wellhead Equipment	$33	$1	$1	$1	$1	$1	$1
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551
Grand Total	**$2,421**	**$2,800**	**$3,402**	**$3,547**	**$3,589**	**$3,606**	**$3,378**

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	$978	$1,041	$1,052	$1,133	$1,233	$1,120	$1,047
Compliance and Documentation	$13	$12	$15	$15	$14	$15	$16
Containment	$98	$85	$86	$76	$80	$139	$146
Rig Requirements	$244	$247	$250	$259	$272	$273	$274
Real Time Monitoring (RTM)	$63	$63	$50	$66	$59	$95	$92
Tubing and Wellhead Equipment	$1	$1	$1	$1	$1	$1	$1
Well Design	$1,357	$1,601	$1,830	$1,981	$2,186	$2,470	$2,382
Grand Total	**$2,753**	**$3,050**	**$3,284**	**$3,531**	**$3,845**	**$4,113**	**$3,957**

Source: Quest Offshore Resources, Inc.

Table 16: US Gulf of Mexico Production by Type – Proposed Rule Scenario (Thousands)[13]

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,693	1,724	1,745	1,760
Gas - BOE/D	1,119	909	765	662	634	548	550	541	544	555	574
Total	**2,682**	**2,248**	**2,056**	**1,937**	**2,045**	**2,047**	**2,183**	**2,234**	**2,268**	**2,299**	**2,334**

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,758	1,742	1,730	1,718	1,712	1,717	1,730	1,733	1,740	1,748
Gas - BOE/D	593	613	635	656	683	718	760	796	834	876
Total	**2,351**	**2,355**	**2,364**	**2,374**	**2,396**	**2,435**	**2,490**	**2,529**	**2,573**	**2,623**

Source: Quest Offshore Resources, Inc.

Table 17: US Gulf of Mexico Production by Type – Base Development Scenario (Thousands)

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,722	1,799	1,833	1,874
Gas - BOE/D	1,119	909	765	662	634	548	550	558	583	602	634
Total	**2,682**	**2,248**	**2,056**	**1,937**	**2,045**	**2,047**	**2,183**	**2,280**	**2,381**	**2,435**	**2,508**

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,916	1,920	1,938	1,944	1,969	1,990	2,018	2,035	2,044	2,051
Gas - BOE/D	674	704	742	774	817	863	915	963	1,006	1,052
Total	**2,590**	**2,624**	**2,679**	**2,718**	**2,787**	**2,852**	**2,933**	**2,999**	**3,050**	**3,104**

Source: Quest Offshore Resources, Inc.

Table 18: Government Revenues by Source – Proposed Rule Scenario ($Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	$238	$218	$218	$236	$232	$182	$217	$236	$237	$241	$263
Bids	$920	$325	$1,815	$1,299	$976	$707	$1,041	$1,041	$1,051	$1,039	$1,161
Royalties	$5,203	$5,635	$5,481	$5,684	$5,870	$4,288	$5,755	$6,112	$6,245	$6,466	$6,685
Total	**$6,361**	**$6,177**	**$7,515**	**$7,219**	**$7,079**	**$5,177**	**$7,013**	**$7,389**	**$7,533**	**$7,746**	**$8,110**

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	$263	$291	$294	$290	$306	$333	$331	$338	$350	$370
Bids	$1,135	$1,249	$1,252	$1,231	$1,286	$1,389	$1,373	$1,392	$1,432	$1,502
Royalties	$6,869	$7,017	$7,195	$7,368	$7,573	$7,859	$8,160	$8,418	$8,706	$8,998
Total	**$8,267**	**$8,557**	**$8,740**	**$8,889**	**$9,164**	**$9,580**	**$9,865**	**$10,148**	**$10,488**	**$10,870**

Source: Quest Offshore Resources, Inc.

[13] 2010 to 2014 Production is actual production.

Table 19: Government Revenues by Source – Base Development Scenario ($Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	$238	$218	$218	$236	$232	$182	$217	$245	$261	$247	$281
Bids	$920	$325	$1,815	$1,299	$976	$707	$1,041	$1,084	$1,158	$1,067	$1,237
Royalties	$5,203	$5,635	$5,481	$5,684	$5,870	$4,288	$5,755	$6,296	$6,631	$6,948	$7,311
Total	**$6,361**	**$6,177**	**$7,515**	**$7,219**	**$7,079**	**$5,177**	**$7,013**	**$7,625**	**$8,050**	**$8,262**	**$8,828**

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	$275	$285	$298	$305	$342	$322	$337	$341	$373	$391
Bids	$1,188	$1,222	$1,270	$1,294	$1,437	$1,344	$1,397	$1,404	$1,525	$1,590
Royalties	$7,725	$8,012	$8,385	$8,708	$9,130	$9,582	$10,046	$10,477	$10,879	$11,273
Total	**$9,188**	**$9,518**	**$9,953**	**$10,307**	**$10,909**	**$11,247**	**$11,780**	**$12,222**	**$12,777**	**$13,254**

Source: Quest Offshore Resources, Inc.

Table 20: Project Development Spending by Component – Proposed Rule Scenario ($Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	$6,069	$6,270	$8,188	$7,610	$9,411	$7,862	$8,069	$8,547	$9,611	$10,611	$10,404
Engineering	$2,098	$2,517	$2,206	$2,022	$1,940	$1,297	$2,463	$3,065	$2,981	$2,632	$2,522
G&G	$183	$163	$348	$368	$439	$319	$372	$321	$305	$354	$383
Install	$1,918	$631	$762	$2,791	$2,995	$1,442	$1,084	$837	$1,152	$1,401	$1,377
OPEX	$19,533	$19,466	$18,920	$18,355	$17,836	$17,845	$17,766	$17,629	$17,052	$16,791	$16,351
Platforms	$3,215	$4,150	$3,620	$2,715	$2,530	$1,700	$2,960	$1,717	$2,105	$2,025	$1,922
SURF	$2,098	$2,513	$2,051	$1,613	$1,503	$1,144	$2,213	$2,781	$2,545	$2,640	$2,686
Total	**$35,114**	**$35,710**	**$36,095**	**$35,473**	**$36,653**	**$31,609**	**$34,927**	**$34,897**	**$35,750**	**$36,454**	**$35,643**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	$9,329	$8,487	$7,827	$7,714	$8,034	$9,061	$11,381	$13,610	$13,692	$13,057
Engineering	$2,583	$2,809	$2,809	$3,123	$3,814	$4,066	$3,412	$2,591	$2,482	$2,585
G&G	$413	$414	$403	$392	$391	$399	$423	$451	$473	$475
Install	$1,069	$1,051	$1,325	$1,522	$1,134	$851	$1,364	$1,966	$1,958	$1,849
OPEX	$15,983	$15,866	$15,379	$15,153	$14,655	$14,485	$14,471	$13,797	$13,566	$14,253
Platforms	$2,100	$2,666	$2,383	$2,453	$3,223	$3,418	$2,253	$1,312	$1,795	$2,058
SURF	$2,800	$2,870	$2,862	$2,651	$3,272	$3,491	$3,031	$2,334	$2,170	$2,257
Total	**$34,276**	**$34,163**	**$32,987**	**$33,007**	**$34,523**	**$35,771**	**$36,336**	**$36,061**	**$36,136**	**$36,534**

Source: Quest Offshore Resources, Inc.

Table 21: Project Development Spending by Component – Base Development Scenario ($Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	$6,069	$6,270	$8,188	$7,610	$9,411	$7,862	$8,069	$8,271	$10,350	$12,436	$12,977
Engineering	$2,098	$2,517	$2,206	$2,022	$1,940	$1,297	$2,463	$2,849	$2,775	$2,171	$2,008
G&G	$183	$163	$348	$368	$439	$319	$372	$357	$339	$393	$426
Install	$1,918	$631	$762	$2,791	$2,995	$1,442	$1,084	$924	$1,416	$2,182	$2,539
OPEX	$19,533	$19,466	$18,920	$18,355	$17,836	$17,845	$17,766	$17,629	$17,326	$17,263	$16,671
Platforms	$3,215	$4,150	$3,620	$2,715	$2,530	$1,700	$2,960	$3,443	$3,933	$3,134	$2,914
SURF	$2,098	$2,513	$2,051	$1,613	$1,503	$1,144	$2,213	$2,617	$2,418	$1,968	$2,027
Total	**$35,114**	**$35,710**	**$36,095**	**$35,473**	**$36,653**	**$31,609**	**$34,927**	**$36,089**	**$38,557**	**$39,548**	**$39,563**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	$11,106	$9,223	$9,272	$9,274	$9,156	$10,543	$12,255	$14,324	$14,845	$15,305
Engineering	$2,127	$2,373	$2,448	$2,684	$3,246	$3,813	$3,417	$2,395	$1,877	$1,703
G&G	$459	$460	$448	$435	$435	$443	$470	$501	$526	$527
Install	$2,051	$1,936	$2,253	$2,433	$1,943	$1,393	$1,745	$2,764	$3,325	$3,655
OPEX	$16,810	$17,390	$16,854	$16,500	$15,973	$15,983	$15,924	$15,990	$15,676	$16,148
Platforms	$3,245	$3,844	$3,942	$3,932	$4,355	$5,045	$4,792	$3,572	$3,182	$2,674
SURF	$2,282	$2,396	$2,207	$2,394	$3,003	$3,376	$3,055	$2,181	$1,712	$1,546
Total	**$38,080**	**$37,620**	**$37,424**	**$37,652**	**$38,111**	**$40,596**	**$41,657**	**$41,726**	**$41,142**	**$41,557**

Source: Quest Offshore Resources, Inc.

Table 22: Government Revenues by Recipient – Proposed Rule Scenario ($Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	$6,359	$6,176	$7,515	$7,219	$7,075	$5,172	$7,008	$6,889	$7,033	$7,246	$7,610
State Totals	$3	$1	$0	$0	$4	$5	$5	$500	$500	$500	$500
Texas	$0	$0	$0	$0	$0	$1	$1	$150	$150	$150	$150
Louisiana	$1	$0	$0	$0	$1	$2	$2	$150	$150	$150	$150
Mississippi	$1	$0	$0	$0	$1	$1	$1	$125	$125	$125	$125
Alabama	$1	$0	$0	$0	$1	$1	$1	$75	$75	$75	$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	$7,767	$8,057	$8,240	$8,389	$8,664	$9,080	$9,365	$9,648	$9,988	$10,370
State Totals	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Texas	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Louisiana	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Mississippi	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
Alabama	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75

Source: Quest Offshore Resources, Inc.

Table 23: Government Revenues by Recipient – Base Development Scenario ($Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	$6,359	$6,176	$7,515	$7,219	$7,075	$5,172	$7,008	$7,125	$7,550	$7,762	$8,328
State Totals	$3	$1	$0	$0	$4	$5	$5	$500	$500	$500	$500
Texas	$0	$0	$0	$0	$0	$1	$1	$150	$150	$150	$150
Louisiana	$1	$0	$0	$0	$1	$2	$2	$150	$150	$150	$150
Mississippi	$1	$0	$0	$0	$1	$1	$1	$125	$125	$125	$125
Alabama	$1	$0	$0	$0	$1	$1	$1	$75	$75	$75	$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	$8,688	$9,018	$9,453	$9,807	$10,409	$10,747	$11,280	$11,722	$12,277	$12,754
State Totals	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Texas	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Louisiana	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Mississippi	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
Alabama	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75

Source: Quest Offshore Resources, Inc.

Table 24: Total Employment – Base Development and Proposed Rule Scenarios in Thousands

Scenario	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Direct	139	139	136	140	142	118	134	139	146	148	148
Base Indirect	270	271	272	272	279	245	266	280	294	301	300
Proposed Direct	139	139	136	140	142	118	134	134	136	138	135
Proposed Indirect	270	271	272	272	279	245	266	277	281	285	278
Base Total	**409**	**409**	**408**	**412**	**421**	**363**	**400**	**419**	**441**	**449**	**449**
Proposed Total	**409**	**409**	**408**	**412**	**421**	**363**	**400**	**412**	**417**	**423**	**413**

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Direct	144	145	145	148	150	158	159	156	154	155
Base Indirect	290	287	285	286	288	303	309	311	307	312
Proposed Direct	131	133	130	131	137	141	139	135	135	136
Proposed Indirect	267	266	257	257	266	274	278	276	275	278
Base Total	**434**	**433**	**430**	**434**	**438**	**461**	**469**	**467**	**460**	**467**
Proposed Total	**398**	**399**	**387**	**388**	**403**	**415**	**418**	**411**	**409**	**414**

Source: Quest Offshore Resources, Inc.

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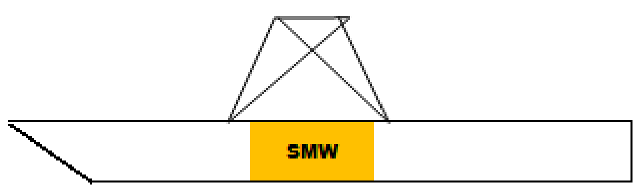
Attachment for 250.414 (c) (1)

Guidance for Surface and Downhole Mud Weight
When using Synthetic Based Mud (SBM), there may be a significant difference between Surface Mud Weight (SMW) and Downhole Mud Weight (DHMW) due to compressibility and thermal effects. This delta must be accounted for on deep, complex wells on a case-by-case basis. However, many wells are drilled with Water Based Mud (WBM) or to shallow depths with SBM where the delta is inconsequential. Therefore, the requirement to use DHMW in this clause is overly prescriptive as it will add unnecessary complexity to all wells, thereby diluting the focus of engineering and operational personnel on more pressing process safety issues.

- The following terms are clearly defined in the diagrams below:
  - Surface Mud Weight (SMW)
  - Downhole Mud Weight (DHMW)
  - Equivalent Static Density (ESD)
  - Equivalent Circulating Density (ECD)

Figure 1
The surface mud weight is measured at the surface.



Surface Mud Weight (SMW)

Figure 2
The Downhole mud weight is affected by various factors.

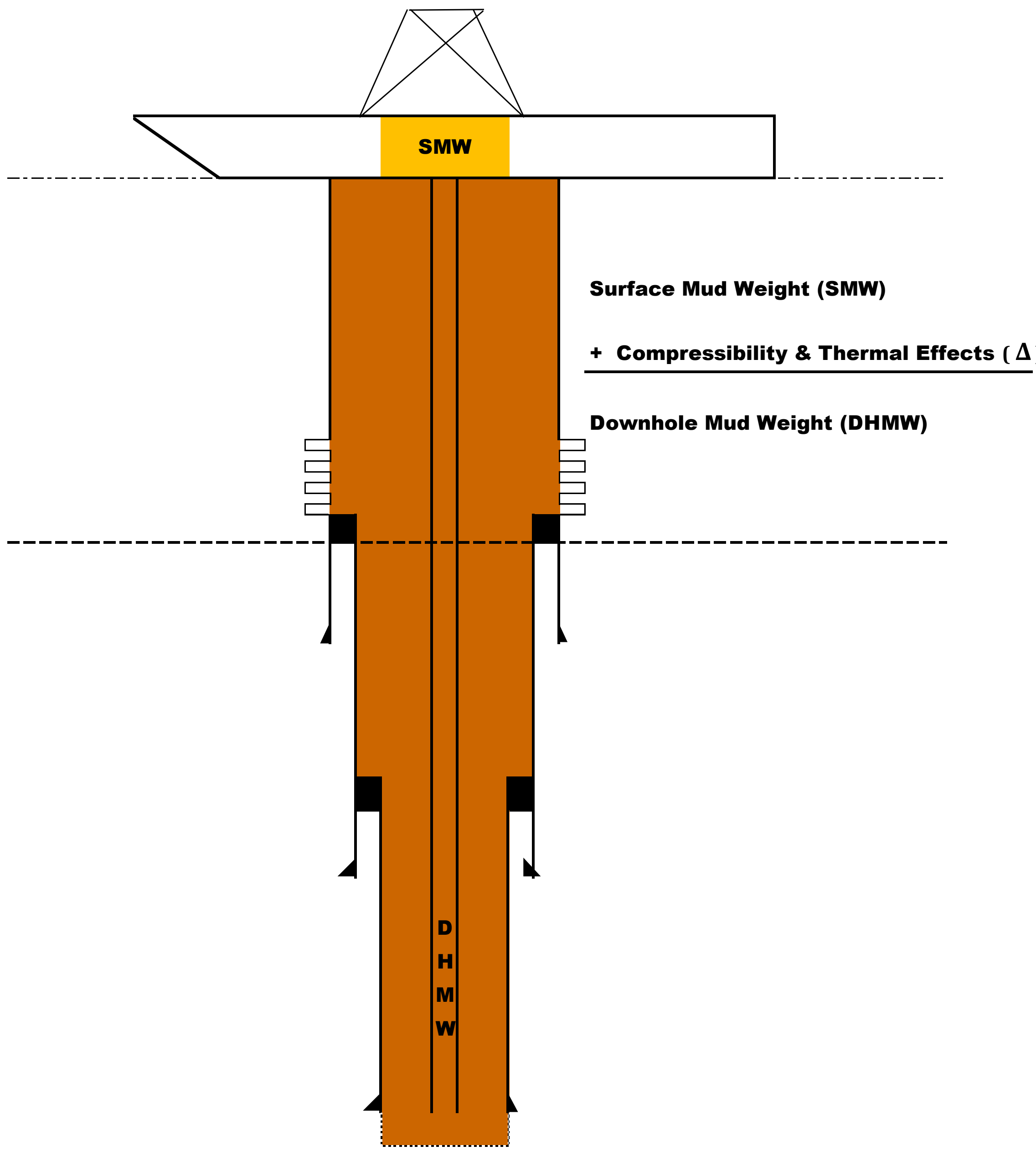


Figure 3

The equivalent static density is the downhole mud weight with the cuttings load.

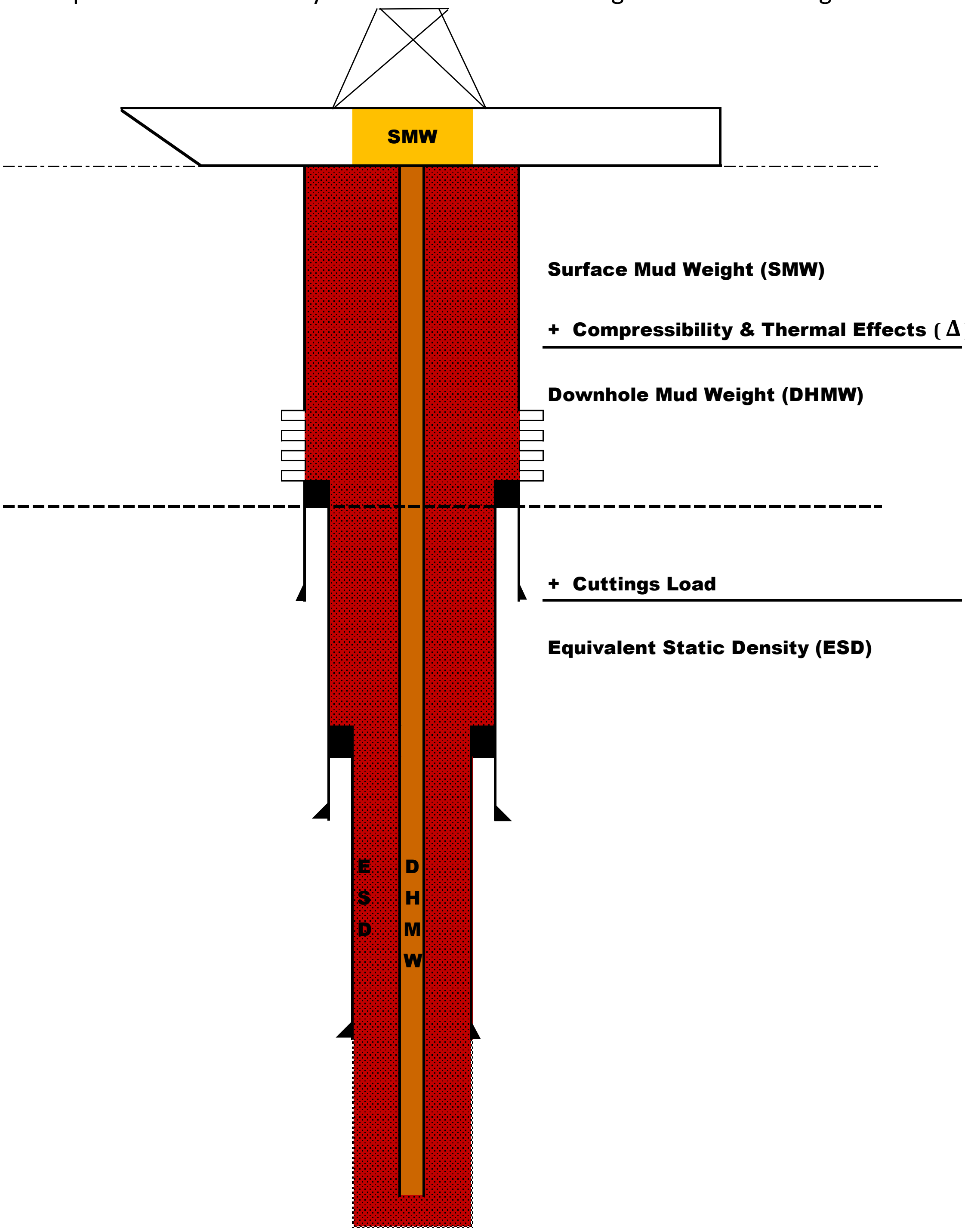
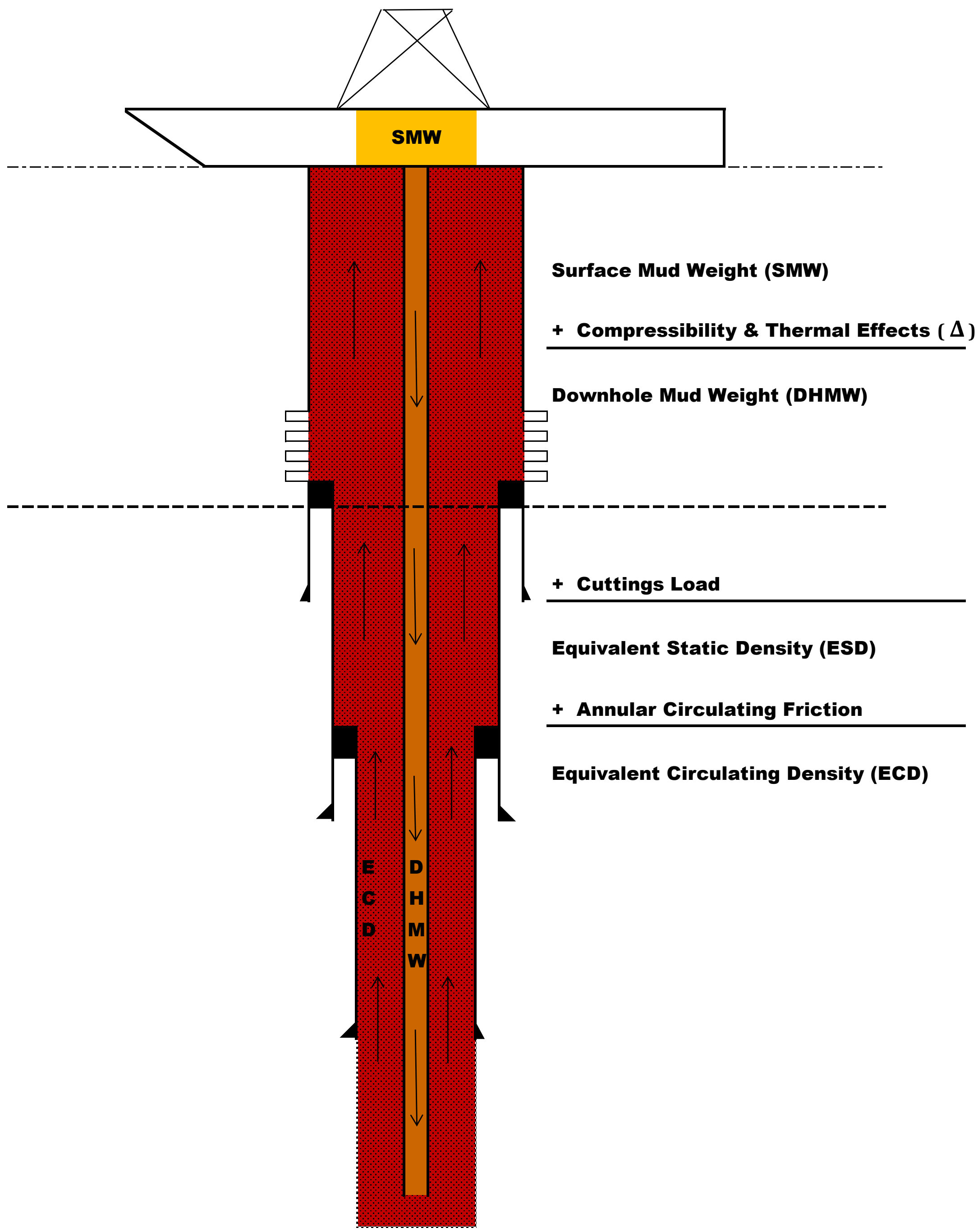


Figure 4
The ECD is the ESD plus the effect of annular circulating friction. When recorded by a tool, a calculation is required to determine the ECD at any depth other than the tool depth. (i.e., when the tool is measuring ECD below the casing shoe).



In summary, many calculations are required to calculate downhole mudweights. Examples include but are not limited to:

- DHMW = SMW +   H (Mud Compressibility & Thermal Effects)
- ESD = DHMW + Cuttings Load
- ECD = ESD + Annular Friction or
- ECD = DHMW + Cuttings Load + Annular Friction

Figure 5
How to determine the effect of mud compressibility and thermal effects at a drilling rig

- Prior to performing the PIT, 3 ESD's are pumped up and averaged (ESD_a)
- At this point the cuttings load in the well is negligible, so

  ESD_a = DHMW
- Therefore

  $\Delta = ESD_a - SMW$

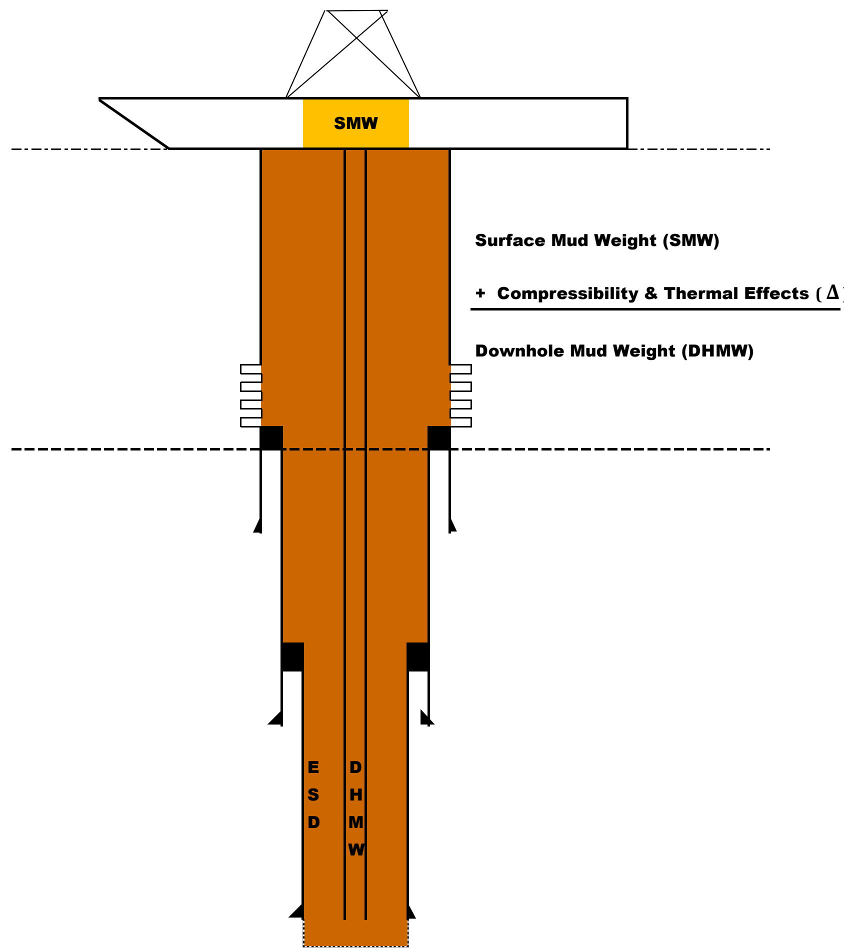
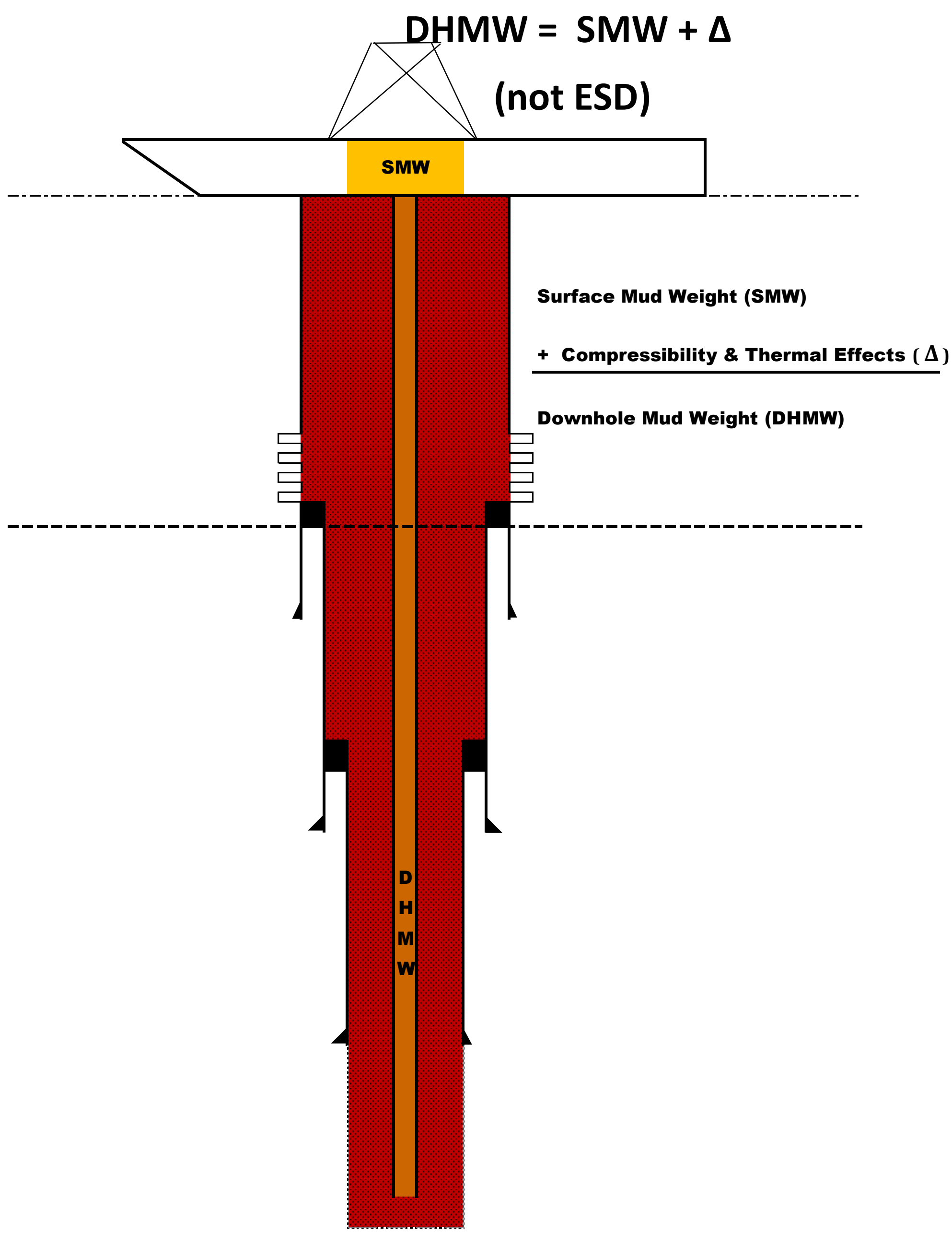


Figure 6

Correct usage requires a clear understanding of downhole conditions to determine the DHMW in relation to a weak point or shoe in the well while drilling.

This DHMW can be used to assure that the Drilling margin is maintained as compared to the weakest know point in the interval as per the PP/FG curve (always in DHMW).



Clarification for usage of delta

- For Lessees that are using WBM, OR t the Drilto shallow depths with SBM (“inconsequential delta” -no PWD or hydraulic modelling required):

SMW + delta = W + d

12.0+ de 2.   + delta

- For Lessees that are drilling deep, deepwater wells (r wells (are drilling deep, deepwater wells (ow depths with SBM

SMW + delta = W + d
12.0+ de 2.0+   + delta

Attachment for 250.414 (c) (2)

Drilling Margin

Industry acknowledges the safety concerns BSEE has regarding drilling margins and the need for increased vigilance. Avoidance of incidents is paramount, especially in difficult hole sections. Industry has consistently shown the ability to be able to drill without arbitrary prescriptive safety margins, through safe drilling practices.

For example, API 92L addresses the effects of drilling margins in difficult hole sections.
"Drilling margin only applies to operations conducted while drilling. The drilling margin is the difference between the mud weight in use and the lowest exposed formation fracture gradient. The fracture gradient is first measured at the casing shoe when it is drilled out using either a formation integrity test (FIT), which is taken to a pre-determined pressure, or a leakoff test (LOT), whereby whole mud is pumped into the formation to establish the formation strength. Operators should use local knowledge to determine which test (FIT or LOT) best supports the well construction objectives. The lowest exposed fracture gradient may also be measured after the shoe test in open hole with an ECD FIT test.

Some of the factors affecting the selection of a drilling margin include depth, open-hole interval exposure, temperature, fracture gradient and mud properties (mud weight without cuttings). The formation strength component of a GOM drilling margin may be negatively affected by a LOT that is conducted using a synthetic or an oil base mud.

A prescriptive fixed safe drilling margin can result in unintended consequences as follows:

1. *A 0.5 ppg safe drilling margin at 7,700 ft TVD results in a 200 psi pressure differential, while at 30,000 ft TVD this safe drilling margin increases to a 780 psi difference. At shallower depths than 7,700 ft, a 0.5 ppg safe drilling margin is difficult to implement due to the narrow margin between fracture gradient and pore pressure.*
2. *A drilling margin of 2% of the lowest exposed fracture gradient could be used to accommodate the changing fracture and pore pressure conditions within a drilling well. Unfortunately, even this approach falls short of completely addressing the challenges provided by GOM wells, where well depths can vary from less than 5,000' to greater than 35,000' and where formation strengths vary significantly with lithology (e.g., salt, limestone, sand, shale) and water depth.*

Therefore, prescriptive drilling margins are not recommended, rather a risk assessment should be performed to establish safe drilling margins for each well and for each drilling interval within the well.

Using a relevant drilling margin should result in well control and kick recognition being maintained when drilling ahead with losses. The drilling margin should be risk-assessed and calculated based on sound engineering practices. Bottom hole pressure (hydrostatic pressure plus applied surface pressure, as applicable) must be greater than pore pressure. The drilling margin should be reassessed if lost circulation conditions change."

Another unintended consequence is that an operator may be forced to drill very near to balance to maintain the mandated "Safe" Drilling Margin in order to achieve the well objectives, incurring unanticipated, unnecessary risks. Alternatively BSEE could use the definition of drilling margin as defined in API 96. This will eliminate the effect of mud weight when determining a safe drilling margin. API 96 defines drilling margin as "*the difference between the maximum pore pressure and the minimum effective fracture pressure. It is used while drilling and can be determined for any point within an open hole interval*." Alternatively, to meet the "Safe" drilling margin requirement, an operator may be forced into setting surface casing deeper into a pressured environment to obtain the required "Safe" drilling margin for the next hole interval.

As already noted, many of the wells in Deepwater set every string of pipe available to get the required casing size for production equipment at total depth. Industry has optimized the use of the current 18 ¾"wellhead and 18 ¾" BOP sizes such that there is not any space in the wellhead for more casing strings to be added. This optimization has been intensely pursued by industry for the past 16 years. For the deeper depth wells there are no shallow pays, all the productive interval is near total depth. The casing setting depths are critical. To stop short at any point puts the entire well in jeopardy. For shelf wells and deepwater platforms, when drilling through depleted zones, these are normally sidetracks and the casing size is already small, to set extra strings of pipe may not be possible when a reasonable size casing for completion is required.

A review of 175 OCS wells drilled after June 2010 found that 33% required less drilling margin than the proposed rules allow.

The 0.5 ppg safe drilling margin was twice mentioned in the "Increased Safety Measures For Energy Development on the Outer Continental Shelf" (Published May 27, 2010). The 0.5 ppg margin has no technical correlation to deepwater wells or very shallow wells. Macondo was not in a drilling mode and therefore any prescriptive safe drilling margin would not have had a material difference in the loss of well control event.

The industry has clearly demonstrated their ability to safely drill at lower drilling margins using recognized practices and procedures such as those found in API 92L.

Response to Proposed Well Control Rule
§250.420(c)(2)
Casing Cementing Workgroup

Proposed Rule: You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

Proposed Change: You must consider practices which promote the isolation of potential flow zones.

Response 1: The proposed rule will have unintended consequences:

- Increasing mud weight to replace pressure reduction during cement hydration increases the risk of lost circulation, which may result in a failure to attain the top of cement (TOC) necessary for zonal isolation and casing support.
- Increasing mud weight to replace pressure reduction during cement hydration will reduce the density difference between mud, spacer and cement that is otherwise utilized to achieve effective mud removal from the cemented section of the well bore. This reduced difference increases the risk of a leaving a mud channel that permanently compromises zonal isolation (API Standard 65-2, 2nd Edition, Section 5.6.5.2).

Supporting information: Simulations for a group of actual wells demonstrates that wells which can be successfully cemented using current practice cannot be successfully cemented with higher fluid density.

Response 2: The proposed rule is not technically sufficient because:

- Although increasing the pressure applied to the cement slurry increases initial overbalance pressure this pressure is not transmitted through the cement slurry as the cement become self-supporting during cement's Critical Gel Strength Period (cf. SPE 11206, SPE 11416 and calculated in API Standard 65-2, 2nd Edition, Sections A13 and A14).
- Therefore, in the absence of a cement design that addresses the Critical Gel Strength Period, additional hydrostatic overbalance of any amount may be insufficient to address potential flow zones.

<u>Supporting information:</u>

Cooke, C. E., Kluck, M. P. and Medrano, R., "Field Measurements of Annular Pressure and Temperature during Primary Cementing," paper SPE 11206 published in JPT, pp. 1429-1439, August 1983

Cooke, C. E., Kluck, M. P. and Medrano, R., "Annular Pressure and Temperature Measurements Diagnose Cementing Operations," paper SPE 11416 published in JPT, pp. 2181-2186, December 1984

API Standard 65-2, 2nd Edition, Sections A13 and A14 discuss SPE 11206 and SPE 11416, the phenomenon of loss of hydrostatic pressure after cement placement and some of the key results of Cooke's study.

Stiles, D. A., “Successful Cementing in Areas Prone to Shallow Water Flows in Deep-Water Gulf of Mexico,” paper OTC 8305, Presented at the 1997 Offshore Technology Conference, Houston, Texas May 5-8. This paper describes a slurry’s critical hydration period (called “critical gel strength period”, CGSP in API 65-2) in the larger context of total cement system performance and effective mud removal practices.

Mueller, D. T., “Redefining the Static Gel Strength Requirements for Cements Employed in SWF Mitigation,” paper OTC 14282 presented at the 2002 Offshore Technology Conference, Houston, Texas May 6-9. This paper describes the concept of the critical gel strength (called critical static gel strength CSGS in API 65-2) and illustrates that gel strength value which results in the decay of hydrostatic pressure to the point which pressure is balances (hydrostatic pressure equals pore pressure) can be significantly less than the 100 lbf/100 ft^2 value used in the traditional definition of transition time.

Nelson, Erik B. and Guillot, Dominique, editors, “Well Cementing”, Chapter 9: Annular Fluid Migration, Stiles, D. A., 2006. This text is one of the definitive books describing well cementing technology. Chapter 9 describes the consequences and physical process of gas migration, factors affecting migration and methods of predicting it as well as solutions for combatting it and laboratory testing methods.

Response 3: The proposed rule may prohibit the judicious use of unweighted preflushes as a tool for equivalent circulating density (ECD) management.

- In certain wells, pumping a weighted spacer followed by a lighter weight turbulent-flow flush has been used to manage ECD and promote hole cleaning. In such cases, the hydrostatic pressure from 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 optimal ECD Management and hole cleaning.

Supporting information:

Khalilova, P., Koons, B., Lawrence, D., and Elhancha, A., “Newtonian Fluid in Cementing Operations in Deepwater Wells: Friend or Foe?” paper SPE 166456, 2013. The paper describes the factors to be considered when designing cement jobs using turbulent flow fluids as well as the results of five field applications of the technique.

Response 4: The proposed rule is not technically necessary

The purpose of API Standard 65-2, 2nd Edition is to describe methods of isolating potential flow zones during well construction. This standard is already incorporated into the regulations by reference. Proper slurry design coupled with effective mud removal described in API Standard 65-2, 2nd Edition is sufficient to meet the goal of the proposed regulation.

ATTACHMENT F

Operator Response to CFR 250.420(c)(2) as per proposed new BSEE Well Control Rule

Introduction
In response to the proposed CFR 250.420(c)(2) well control rule, the below comparison simulations were run on a typical deep-water development well production liner cement job that was successfully performed in 2013 to isolate multiple HC zones in the annulus without any losses (see below "BASE DESIGN – CASE A"). In order to accommodate the new code as stated in CRF250.420(c)(2), a "REVISED DESIGN – CASE B" is also presented below which incorporates a weighted fluid ahead of the cement to offset the hydrostatic pressure loss during the cement setting process – assuming the cement goes from a 16.3ppg density to 8.34ppg density. Incorporating this weighted fluid ahead of the cementing fluid train during placement significantly enhances the potential for losses and subsequent inability to isolate the HC zones in the annulus.

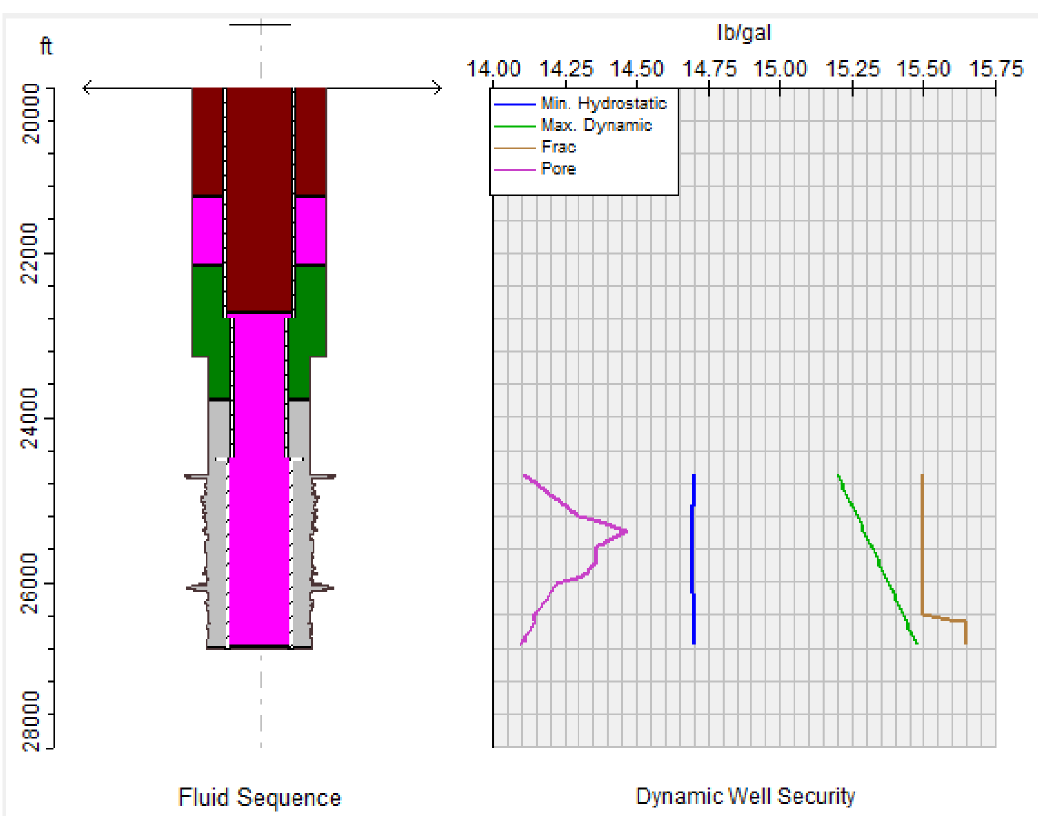
The 1st graph presented in each case shows a snapshot of the maximum ECD during cement placement across the entirety of the wellbore (the green line signifying the maximum ECD and the brown line signifying the fracture gradient of the sands throughout the interval).

The 2nd set of graphs presented in each case show the simulated ECDs at the lowest fracture gradient sand and at casing TD. The light blue line represents the maximum dynamic ECD and the red line represents the fracture gradient at that depth.

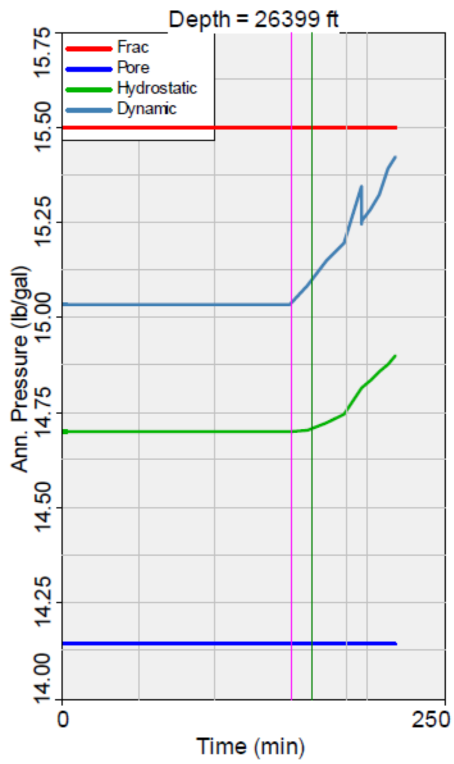
As evidenced by the 2nd case below, incorporating the weighted fluid ahead of the cementing fluids could have jeopardized the successful isolation of the HC zones in the interval due to the increase in cementing ECD and associated lost circulation.

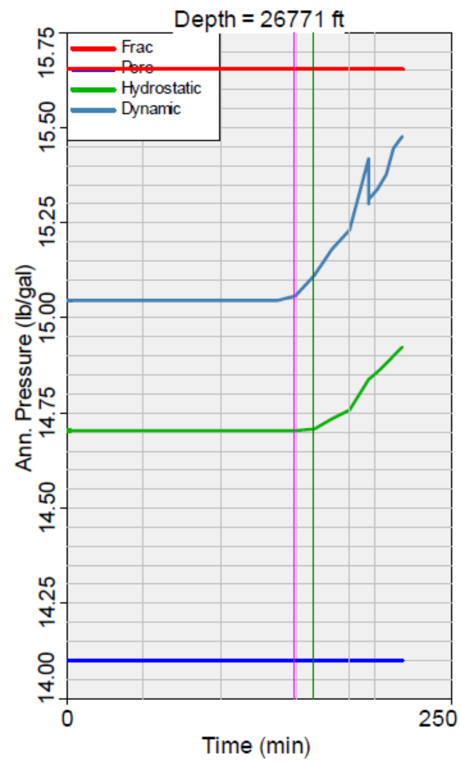
Typical Deepwater Development – CASE A

BASE DESIGN

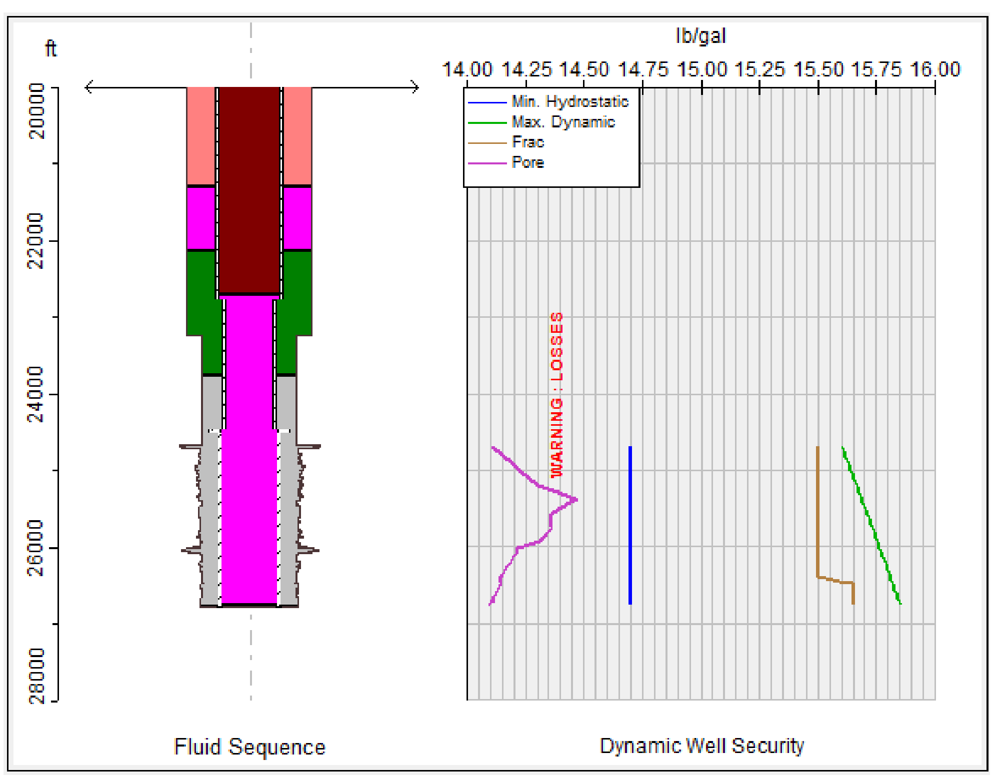


ATTACHMENT F

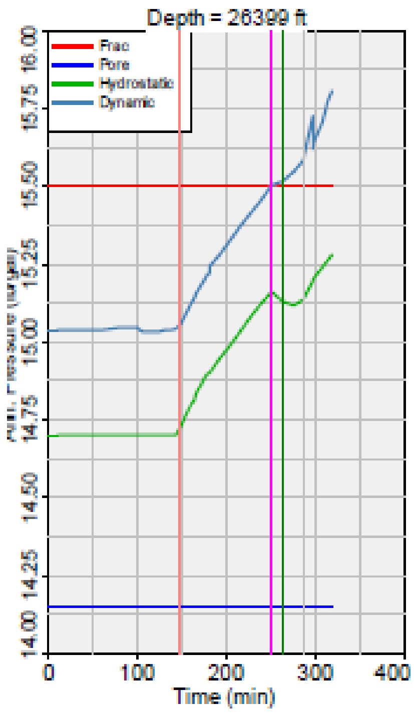


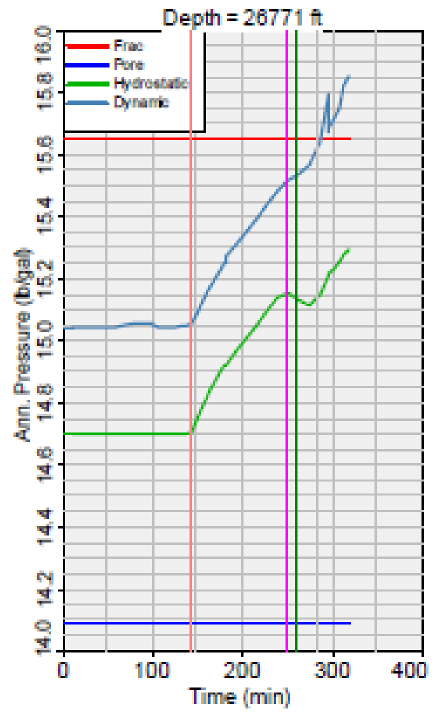


REVISED DESIGN – incorporating 300bbl 16.4ppg slug to restore BASE CASE overbalance pressure assuming cement column density to 8.34ppg



ATTACHMENT F



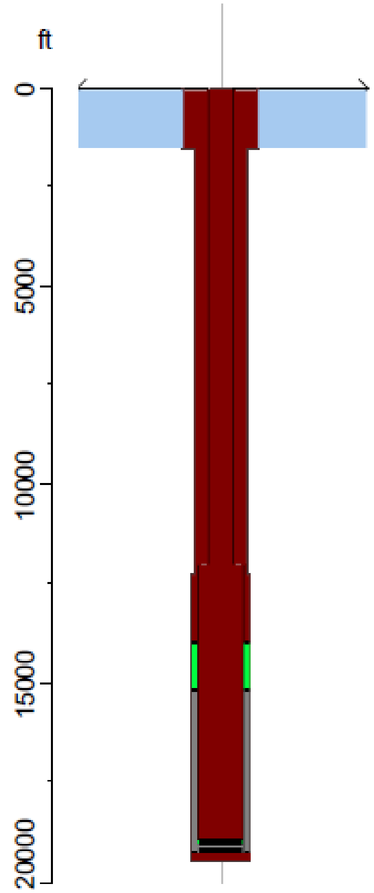


ATTACHMENT G

BSEE Proposed Rule Change Modeling

CFR 250.420

Example #1 –1450' Water Depth (Current Design)



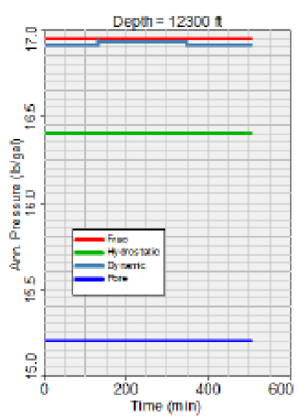
Fluid Sequence

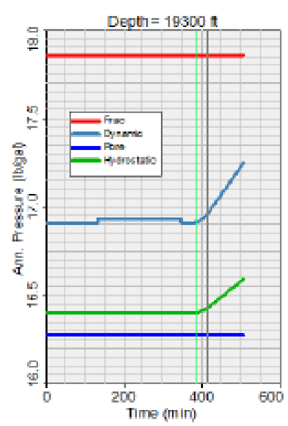
Formation Data				
MD (ft)	**Frac.** (psi)	**Pore** (psi)	**Name**	**Lithology**
11500.0	9971	8945		Shale
12000.0	10463	9380		Shale
12450.0	10903	9779		Shale
14200.0	12514	11294		Shale
15950.0	14133	12850		Shale
17792.0	16116	14537		Evaporite
19450.0	17661	16118		Evaporite

Hydrostatic balance point at the TOS. The salt is assumed benign and not able to flow in this example.

	Name	TP	Volume bbl	Ann.Length ft	Top.MD ft	Density lb/gal	Length ft	Tail Press. psi
1	Spacer	☐	80.0	1189.5	14010.5	16.80	1189.5	12817
2	Tail Slurry	☐	289.1	4100.0	15200.0	17.20	4220.0	16179
3	Tail Slurry	☒	15.0		19045.4	17.20	134.6	15963
4	Spacer	☐	10.0		18955.7	16.80	89.7	15889
5	Mud	☐	1181.1		0.0	16.40	18955.7	0

Hydrostatic head at the TOC during setting time

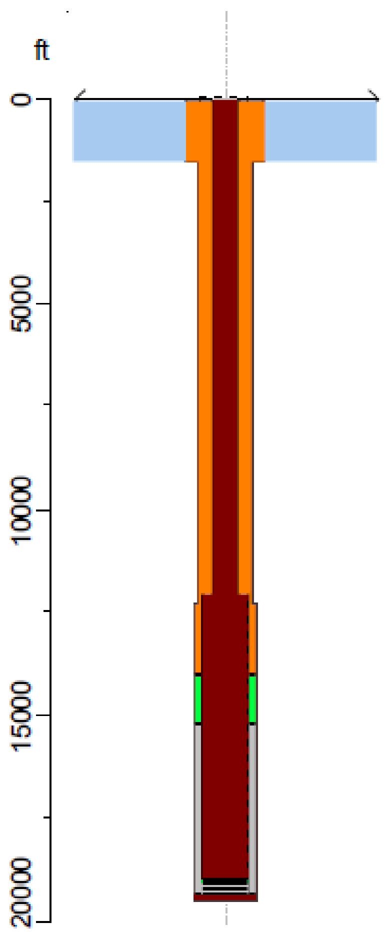




Static Security Checks :		
Frac	347 psi	at 12300.0 ft
Pore	283 psi	at 19450.0 ft
Collapse	3391 psi	at 19180.0 ft
Burst	9120 psi	at 14010.5 ft

Dynamic Security Checks :		
Frac	7 psi	at 12300.0 ft
Pore	99 psi	at 19450.0 ft
Collapse	3391 psi	at 19180.0 ft
Burst	8430 psi	at 12000.0 ft

Example #1 – Proposed BSEE language design

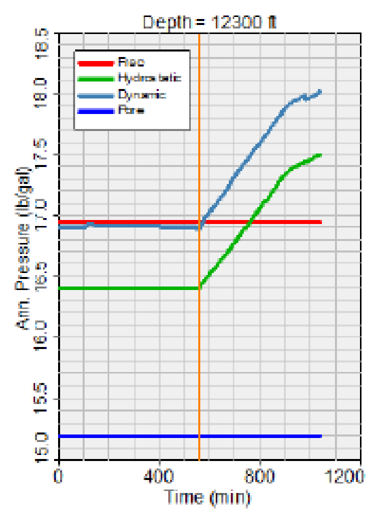


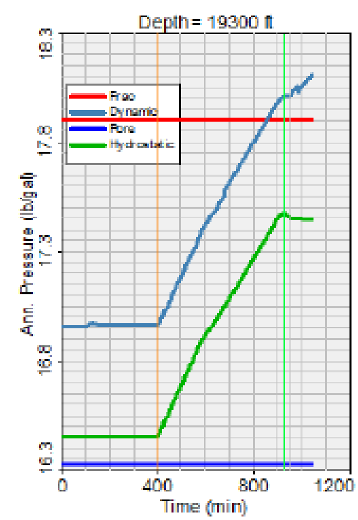
Fluid Sequence

	Name	TP	Volume bbl	Ann.Length ft	Top.MD ft	Density lb/gal	Length ft	Tail Press. psi
1	Heavy Mud	☐	1643.9	13926.5	84.0	17.50	13926.5	12629
2	Spacer	☐	80.0	1189.5	14010.5	16.80	1189.5	13611
3	Tail Slurry	☐	289.1	4100.0	15200.0	0.10	4220.0	13630
4	Tail Slurry	☒	15.0		19045.4	0.10	134.6	15963
5	Spacer	☐	10.0		18955.7	16.80	89.7	15889
6	Mud	☐	1181.1		0.0	16.40	18955.7	0

Hydrostatic balance (14537 psi) can not be achieved with 17.5 ppg mud back to surface.

Cement density assumed to be 0.1 ppg when setting





ECD plots assume cement density (17.2 ppg) during placement

Dynamic Security Checks :

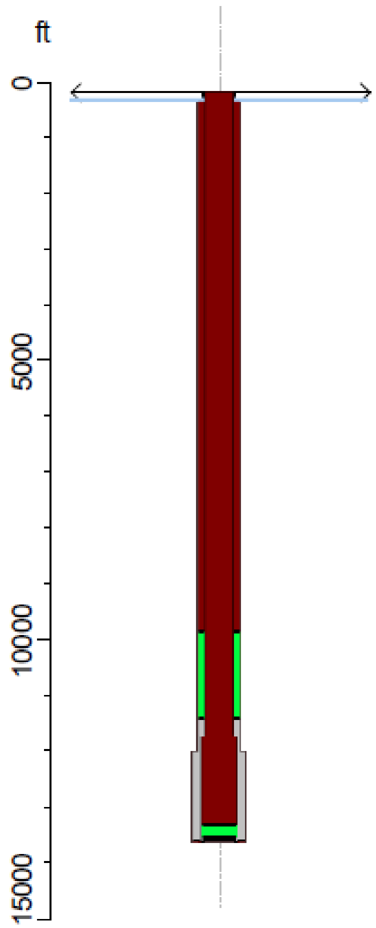
Frac	-675 psi	at 12300.0 ft
Pore	99 psi	at 19450.0 ft
Collapse	2598 psi	at 19180.0 ft
Burst	8317 psi	at 12000.0 ft

Static Security Checks :

Frac	-351 psi	at 12300.0 ft
Pore	1077 psi	at 19450.0 ft
Collapse	2598 psi	at 19180.0 ft
Burst	9190 psi	at 19180.0 ft

ATTACHMENT G

Example #2 – Shelf (Current Design)



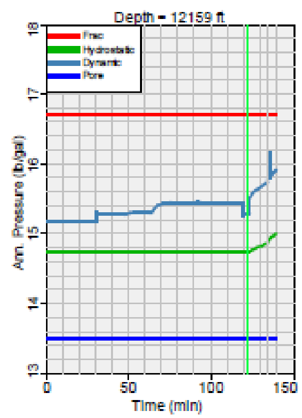
Fluid Sequence

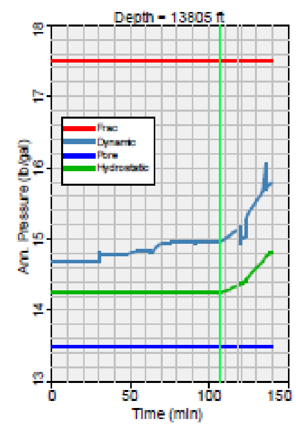
MD (ft)	Frac. (psi)	Pore (psi)	Name	Lithology
6172.5	4476	2622		Shale
12159.0	9778	7846		Shale
13445.0	11622	8965		Shale
13446.0	11623	8966	KA Sand	Sandstone
13650.0	11791	9096	KA Sand	Sandstone
13814.0	11926	9200		Shale

Hydrostatic balance point at the base of the potential flow zone.

	Name	TP	Volume bbl	Ann.Length ft	Top MD ft	Density lb/gal	Length ft	Tail Press. psi
1	Spacer	☐	60.0	1611.4	9938.6	15.50	1611.4	8257
2	7 5/8" Slurry	☐	92.0	2255.0	11550.0	17.20	2335.0	10019
3	Spacer	☒	10.0		13490.5	15.50	234.5	9594
4	Mud	☐	362.9		0.0	14.40	13490.5	0

Hydrostatic head at the TOC during setting time

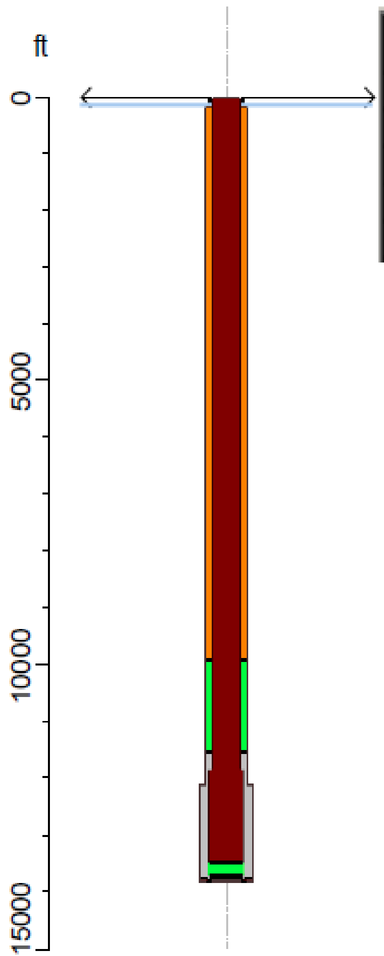




Dynamic Security Checks :		
Frac	319 psi	at 12159.0 ft
Pore	493 psi	at 13445.0 ft
Collapse	9546 psi	at 13725.0 ft
Burst	11905 psi	at 11850.0 ft

Static Security Checks :		
Frac	1026 psi	at 12140.0 ft
Pore	827 psi	at 13445.0 ft
Collapse	9546 psi	at 13725.0 ft
Burst	12620 psi	at 13725.0 ft

Example #2 – Proposed BSEE language design

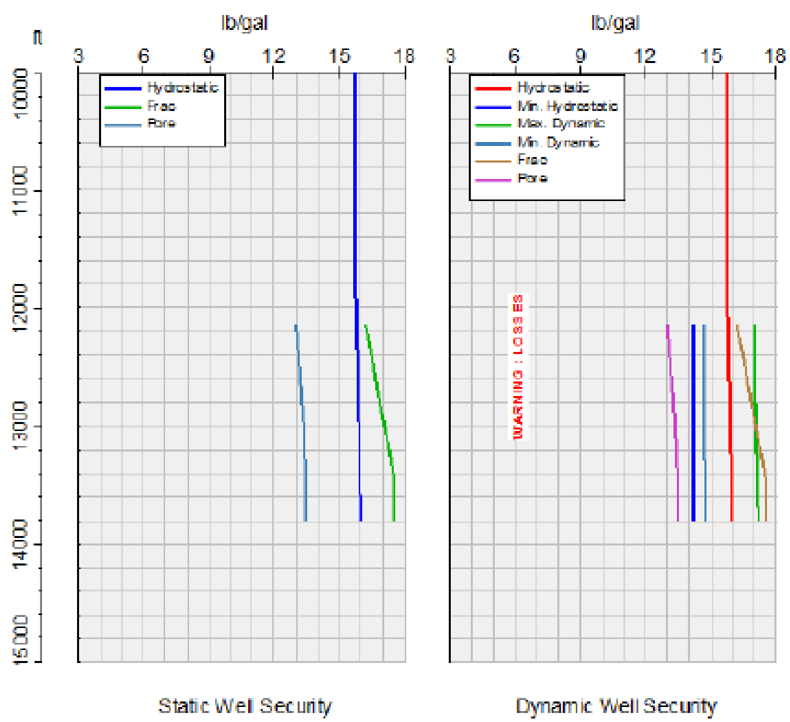


Fluid Sequence

	Name	TP	Volume bbl	Ann.Length ft	Top.MD ft	Density lb/gal	Length ft	Tail Press. psi
1	Heavy Mud		365.0	9752.6		16.00	9752.6	7865
2	Spacer		60.0	1611.4	9938.6	15.50	1611.4	9040
3	7 5/8" Slurry		92.0	2255.0	11550.0	0.10	2335.0	9051
4	Spacer	X	10.0		13490.5	15.50	234.5	9594
5	Mud		362.9		0.0	14.40	13490.5	0

Hydrostatic balance (9096 psi) can not be achieved with 16.0 ppg mud back to surface.

Cement density assumed to be 0.1 ppg when setting



ECD plots assume cement density (17.2 ppg) during placement

Dynamic Security Checks :		
Frac	-466 psi	at 12159.0 ft
Pore	493 psi	at 13445.0 ft
Collapse	8763 psi	at 13725.0 ft
Burst	11905 psi	at 11850.0 ft

Static Security Checks :		
Frac	243 psi	at 12140.0 ft
Pore	1610 psi	at 13445.0 ft
Collapse	8763 psi	at 13725.0 ft
Burst	12620 psi	at 13725.0 ft