NATIONAL ARCHIVES AND RECORDS ADMINISTRATION
LITTERA SCRIPTA MANET
1985

FEDERAL REGISTER

Vol. 77 Wednesday,
No. 163 August 22, 2012

Part III

Department of the Interior

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

Oil and Gas and Sulphur Operations on the Outer Continental Shelf—Increased Safety Measures for Energy Development on the Outer Continental Shelf; Final Rule

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

[Docket ID BSEE–2012–0002]

RIN 1014–AA02

Oil and Gas and Sulphur Operations on the Outer Continental Shelf—Increased Safety Measures for Energy Development on the Outer Continental Shelf

AGENCY: Bureau of Safety and Environmental Enforcement (BSEE), Interior.

ACTION: Final rule.

SUMMARY: This Final Rule implements certain safety measures recommended in the report entitled, ''Increased Safety Measures for Energy Development on the Outer Continental Shelf.'' To implement the appropriate recommendations in the Safety Measures Report and DWH JIT report, BSEE is amending drilling, well-completion, well-workover, and decommissioning regulations related to well-control, including: subsea and surface blowout preventers, well casing and cementing, secondary intervention, unplanned disconnects, recordkeeping, and well plugging.

DATES: *Effective Date:* This rule becomes effective on October 22, 2012. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of October 22, 2012.

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Executive Summary

On October 14, 2010, the Bureau of Offshore Energy Management, Regulation, and Enforcement (BOEMRE) published the Interim Final Rule (75 FR 63346), ''Increased Safety Measures for Energy Development on the Outer Continental Shelf.'' The Interim Final Rule (IFR) addressed certain recommendations from the Secretary of the Interior to the President entitled, ''Increased Safety Measures for Energy Development on the Outer Continental Shelf'' (Safety Measures Report). The Bureau of Safety and Environmental Enforcement (BSEE) is publishing this Final Rule in response to comments on the requirements implemented in the IFR. This rulemaking:

- Establishes new casing installation requirements;
- Establishes new cementing requirements;
- Requires independent third party verification of blind-shear ram capability;
- Requires independent third party verification of subsea BOP stack compatibility;
- Requires new casing and cementing integrity tests;
- Establishes new requirements for subsea secondary BOP intervention;
- Requires function testing for subsea secondary BOP intervention;
- Requires documentation for BOP inspections and maintenance;
- Requires a Registered Professional Engineer to certify casing and cementing requirements; and
- Establishes new requirements for specific well control training to include deepwater operations.

This Final Rule changes the Interim Final Rule (IFR) in the following ways:

- Updates the incorporation by reference to the second edition of API Standard 65—Part 2, which was issued December 2010. This standard outlines the process for isolating potential flow zones during well construction. The new Standard 65—Part 2 enhances the description and classification of well-control barriers, and defines testing requirements for cement to be considered a barrier.
- Revises requirements from the IFR on the installation of dual mechanical barriers in addition to cement for the final casing string (or liner if it is the final string), to prevent flow in the event of a failure in the cement. The Final Rule provides that, for the final casing string (or liner if it is the final string), an operator must install one mechanical barrier in addition to cement, to prevent flow in the event of a failure in the cement. The final rule also clarifies that float valves are not mechanical barriers.
- Revises § 250.423(c) to require the operator to perform a negative pressure test only on wells that use a subsea blowout preventer (BOP) stack or wells with a mudline suspension system instead of on all wells, as was provided in the Interim Final Rule.
- Adds new § 250.451(j) stating that an operator must have two barriers in place before removing the BOP, and that the BSEE District Manager may require additional barriers.
- Extends the requirements for BOPs and well-control fluids to well-completion, well-workover, and decommissioning operations under Subpart E—Oil and Gas Well-Completion Operations, Subpart F—Oil and Gas Well-Workover Operations, and Subpart Q—Decommissioning Activities to promote consistency in the regulations.

SUPPLEMENTARY INFORMATION:

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I. Background

This Final Rule was initiated as an IFR published by the BOEMRE on October 14, 2010 (75 FR 63346). The IFR was effective immediately, with a 60-day comment period. On October 1, 2011, the BOEMRE, formerly the Minerals Management Service, was replaced by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of the reorganization. This Final Rule falls under the authority of BSEE and as such, a new Regulation Identifier Number (RIN) has been assigned to this rulemaking. The new RIN for this Final Rule is 1014–AA02, and replaces RIN 1010–AD68 from the IFR. This Final Rule modifies, in part, provisions of the IFR based on comments received. After reviewing the comments, however, BSEE retained many of the provisions adopted on October 14, 2010 without change.

Some revisions to the IFR herein are additionally noteworthy in that they respond to comments we received and/or are consistent as possible with recommendations in the Deepwater Horizon Joint Investigation Team (DWH JIT) report, to the degree that those recommendations are within the scope of the IFR or can be considered a logical outgrowth of the IFR. These changes include the following:

- Clarification that the use of a dual float valve is not considered a sufficient mechanical barrier.
- Clarification in § 250.443 stating that all BOP systems must include a wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure instead of the maximum anticipated surface pressure as was previously provided.
- In § 250.1500 revising the definition of well-control to clarify that persons performing well monitoring and maintaining well-control must be trained. This new definition encompasses anyone who has

responsibility for monitoring the well and/or maintaining the well-control equipment.

This Final Rule is promulgated for the prevention of waste and for the conservation of natural resources of the Outer Continental Shelf (OCS), under the rulemaking authority of the Outer Continental Shelf Lands Act (the Act), 43 U.S.C. 1334.

This rule is based on certain recommendations in the May 27, 2010, report from the Secretary of the Interior to the President entitled, ''Increased Safety Measures for Energy Development on the Outer Continental Shelf'' (Safety Measures Report). The President directed that the Department of the Interior (DOI) develop this report as a result of the Deepwater Horizon event on April 20, 2010. This event, which involved a blowout of the BP Macondo well and an explosion on the Transocean Deepwater Horizon mobile offshore drilling unit (MODU), resulted in the deaths of 11 workers, an oil spill of national significance, and the sinking of the Deepwater Horizon MODU. On June 2, 2010, the Secretary of the Interior directed BOEMRE to adopt the recommendations contained in the Safety Measures Report and to implement them as soon as possible. As noted in the regulatory impact analysis accompanying this rule, other recommendations will be addressed in other future rulemakings and will be available for public comment. Final Regulatory Impact Analysis for the Final Rule on Increased Safety Measures for Energy Development on the Outer Continental Shelf, RIN 1014–AA02, at 9 (BSEE; March 7, 2012). Similarly, BSEE's actions here are not intended to supplant any actions by BSEE or other authorized government authorities warranted by fact finding or other factual development in other proceedings, including but not limited to those in Multi-District Litigation No. 2179, In Re: Oil Spill by the OIL RIG DEEPWATER HORIZON in the GULF OF MEXICO, on April 2010 (E.D. La.).

II. Source of Specific Provisions Addressed in the Interim Final Rule

The Safety Measures Report recommended a series of steps designed to improve the safety of offshore oil and gas drilling operations in Federal waters. It outlined a number of specific measures designed to ensure sufficient redundancy in BOPs, promote well integrity, enhance well-control, and facilitate a culture of safety through operational and personnel management. The IFR addressed both new well bore integrity requirements and well-control equipment requirements. The well bore integrity provisions impose requirements for casing and cementing design and installation, tighter cementing practices, the displacement of kill-weight fluids, and testing of independent well barriers. These new requirements were intended to ensure that additional physical barriers exist in wells to prevent oil and gas from escaping into the environment. These new requirements related to well bore integrity were intended to decrease the likelihood of a loss of well-control. The well-control equipment requirements in the IFR help ensure the BOPs will operate in the event of an emergency and that the Remotely Operated Vehicles (ROVs) are capable of activating the BOPs.

The following provisions in the IFR were identified in the Safety Measures Report as being appropriate to implement through an emergency rulemaking:

Safety measures report provision	Interim final rule citations
Establish deepwater well-control procedure guidelines (safety report rec. II.A.1).	§ 250.442 What are the requirements for a subsea BOP system? § 250.515 Blowout prevention equipment. § 250.615 Blowout prevention equipment. §§ 250.1500 through 250.1510 Subpart O—Well-control and Production Safety Training.
Establish new fluid displacement procedures (safety report rec. II.A.2)	§ 250.456 What safe practices must the drilling fluid program follow?
Develop additional requirements or guidelines for casing installation (safety report rec. II.B.2.6).	§ 250.423 What are the requirements for pressure testing casing?

BOEMRE also included the following provision in the IFR from the Safety Measures Report:

Safety measures report provision	Interim final rule
Enforce tighter primary cementing practices (safety report rec.II.B.3.7)	§ 250.415 What must my casing and cementing programs include?

BOEMRE determined that it was appropriate for inclusion in the IFR because it is consistent with the intent of the recommendations in the Safety Measures Report. Tighter requirements for cementing practices increase the safety of offshore oil and gas drilling operations.

Much of the October 14, 2010, **Federal Register** preamble supporting the need for emergency rulemaking procedures also supports retaining these provisions permanently.

III. Overview of the Interim Final Rule as Amended by This Rule

The primary purpose of this Final Rule is to address comments received, make appropriate revisions, and bring to closure the rulemaking begun by the IFR. Together, the two rules clarify and incorporate safeguards that will decrease the likelihood of a blowout during drilling, completion, workover, and abandonment operations on the OCS. For example, the safeguards address well bore integrity and well-control equipment. In sum, the two rules:

(1) Establish new casing installation requirements;

(2) Establish new cementing requirements;

(3) Require independent third-party verification of blind-shear ram capability;

(4) Require independent third-party verification of subsea BOP stack compatibility;

(5) Require new casing and cementing integrity tests;

(6) Establish new requirements for subsea secondary BOP intervention;

(7) Require function testing for subsea secondary BOP intervention;

(8) Require documentation for BOP inspections and maintenance;

(9) Require a Registered Professional Engineer to certify casing and cementing requirements; and

(10) Establish new requirements for specific well-control training to include deepwater operations.

IV. Comments Received on the Interim Final Rule

Although the IFR was effective immediately upon publication in the **Federal Register**, the IFR included a request for public comments. BSEE received 38 comments on the IFR. The following table categorizes the commenters:

Commenter type	Number of comments
Oil and Gas Industry/Organizations	21
Other Non-Government Organizations	6
Individuals	8
Government Federal/State	3
Total	38

A number of comments included topics that were outside the scope of this rulemaking. Some provided suggestions for future rulemakings; other comments related to the Deepwater Horizon event, speculating on the causes of the event and suggesting additional changes based on their understanding of that event. While we requested comments on future rulemakings, we are not specifically addressing those comments in this rule; we will however, consider those suggestions in related future rulemakings. To the degree that comments assert that compliance with current rules or standards incorporated by reference may be infeasible in certain situations, and that such provisions need to be revised, BSEE will examine the need to revise its rules. Pending any future revisions of such provisions, persons subject to compliance may seek BSEE approval of either alternative procedures or equipment under § 250.141 or departures from such requirements under § 250.142. In this Final Rule, BSEE only responds to comments that relate directly to this rulemaking. All comments BSEE received on the IFR are available at *www.regulations.gov* under Docket ID: BSEE–2012–0002.

BSEE received a number of comments asserting that in making the IFR effective immediately upon publication, we did not follow the appropriate rulemaking process as required by the Administrative Procedure Act (APA). BSEE disagrees with these comments. In issuing the IFR, BOEMRE followed procedures authorized under the APA at 5 U.S.C. 553(b) and (d). BOEMRE provided justification in the IFR for not seeking public comment in advance, and for the immediate effective date. BSEE believes that the justification provided at that time was sufficient and will not repeat that justification here.

In this Final Rule, BSEE is publishing revisions to the IFR based on the comments we received. Analysis of the comments also confirms the agency's earlier conclusions regarding those portions of the IFR that are not modified in this Final Rule. To help organize and present the comments received and the BSEE response to the comments, BSEE has developed 3 separate tables. Except for one issue, the following three tables summarize the comments received, and contain BSEE's response to those comments. (Comments pertaining to the ''should/must'' issue related to § 250.198(a) are addressed in the section-by-section discussion with specific comments being addressed in a separate document included in the Administrative Record.) The first table relates to comments received on specific sections. The second table relates to broader topics and general questions not connected to a specific section. The third table addresses comments regarding the Regulatory Impact Analysis. Following the comment discussions, we include a section-by-section analysis of the Final Rule describing changes we made from the IFR. We do not repeat here the basis and purpose for each of the provisions of the sections retained from the IFR.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES

Section—topic	Comment	BSEE response
§ 250.198(h)(79)—API Standard 65 2nd edition.	API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition was published on December 10, 2010. The Second Edition incorporates learnings from the Macondo well incident, enhances the description and classification of well-control barriers, and defines testing requirements for cement to be considered a barrier. The Second Edition also revises Annex D into a checklist based on the requirements of the document. BOEMRE should update the IFR to incorporate the 2nd Edition by reference.	BSEE has reviewed API Standard 65—Part 2 2nd edition and has determined that it is appropriate to incorporate the latest edition in our regulations.
§ 250.198(h)(79)—API Standard 65 2nd edition.	Provide clarification on how API RP 65–2 will be used; will a minimum pre-cementing score be required for each cement job and then evaluated after the job also? (or checklist if using the Second Edition).	BSEE developed a compliance table, based on API Standard 65—Part 2 (see Table 4) for guidance. This Final Rule does not require operators to use this table; however, the operator may answer the questions in the table, along with the written descriptions where needed, or the operator may supply a written description in an alternate format as required in § 250.415(f) which is submitted with the APD. If the operator does not supply enough information to confirm compliance, then BSEE may return the permit application for clarification. BSEE does not plan to use a scoring system; the operator must submit how it evaluated API Standard 65 part 2 when designing its cement program. The operator is not required to submit a post-cement job evaluation.
§ 250.415(f), § 250.416(e)	Will the submittal be with each APD, or once for each rig per year unless changed?	The operator is required to submit the written description of how the best practices in API Standard 65—Part 2 were evaluated and the qualifications of the independent third-party with each APD.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.416(d)	Confirm that the schematic of the control system includes location, control system pressure for BOP functions, BOP functions at each control station, and emergency sequence logic. Specifications on other requirements should be clear.	BSEE agrees that the schematics of the control systems should include these items. The location of control stations are not required to be submitted. While it is critical to have control stations, the actual location of the control stations is not critical.
§ 250.416(e)	Will there be a standard way to perform shearing calculations for the drill pipe?	BSEE does not require a standard method to perform shearing calculations; different manufacturers have different methods of calculating shearing requirements. The documentation the operator provides, however, needs to explain and support the methodology used in performing the calculations and arriving at the test results.
§ 250.416(e)	Will there be a standard of calculation for the Maximum Anticipated Surface Pressure (MASP)?	BSEE does not require a standard procedure for MASP or shearing calculations. In § 250.413(f), MASP for drilling is defined along with the considerations for calculations.
§ 250.416(e)	Will the maximum MASP be the rating of the annulars?	The MASP for shearing calculations will not be based on the annular rating. There are multiple methods to calculate the MASP. It is the responsibility of the operator to select the appropriate method, depending upon the situation.
§ 250.416(e)	Is it a requirement of the deadman to also shear at MASP?	Yes, the shear rams installed in the BOP must be able to shear drill pipe at MASP.
§ 250.416(e)	If there is a requirement of the deadman to also shear at MASP, what usable volume and pressure should remain after actuation?	BSEE is researching this issue and may address it in future rulemaking.
§ 250.416(e)	Please confirm that operators will only be required to demonstrate shearing capacity for drill pipe (which includes workstring and tubing) that is run across the BOP stack and that BHA components, drill collars, HWDP, casing, concentric strings, and lower completion assemblies are excluded from this requirement.	BSEE agrees with this comment. We revised § 250.416 to specifically include workstring and tubing.
§ 250.416(e)	A better requirement would be to demonstrate shearing capacity for drill pipe which includes work-strings and tubing which is run across the BOP stack.	BSEE revised this section in this Final Rule to include workstring and tubing as drill pipe.
§ 250.416(e)	Shearing capacity with MASP should be modified to shearing capacity with mud hydrostatic pressure plus a conservative shut-in pressure limit set by the operator and contractor where shut-in is transferred from the annular BOP to Ram BOP. At this point increased pressure in the cavity between the pipe rams and annular preventer should be eliminated. BOEMRE should request the internal bore pressure shear capacity calculation to be provided at the limit of the BOP system and approval contingent upon MASP being less than internal bore pressure limit.	BSEE requires the operator to design for the case in which blind-shear rams will be exposed to the MASP. BSEE does not agree that we need to request operators to provide the internal bore pressure shear capacity calculation. Designing the BOP for the well design and the conditions in which it will be used will ensure that this concern is addressed.
§ 250.416(e)	Modify the requirement for blind-shear rams to reflect the 2,500 psi maximum pressure limit when placed above all pipe rams and immediately below the annular on the subsea BOP stack. The proposed new API RP–53 4th Edition states pipe rams must be used when shut-in pressure exceeds 2,500 psi. When the blind-shear rams are above all pipe rams in the stack, the well-control sequence would be to shut the annular first and then switch to a pipe ram if the shut-in pressure approaches 2,500 psi. With the blind-shear ram above all pipe rams, it would be nearly impossible for the blind-shear rams to ever experience shut-in pressures approaching MASP.	BSEE disagrees. The operator is required to design for the case in which blind-shear rams are exposed to the MASP. It is possible that this situation may occur and this requirement addresses that possibility.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.416(e)	30 CFR 250.416(e) requires independent third-party verification of pipe shearing calculations at MASP for the blind-shear rams in the BOP stack. Prior to the IFR, this item didn't require the independent third-party verification of shear calculations. Prudent operators always do those calculations to (1) comply with the law as it was written and (2) feel comfortable that pipe can be sheared in an emergency. The requirement for independent third-party verification does not make things safer in the GoM. Why cannot BOEMRE regulators just have the operators do what was already in the regs? Shear calculations are very straight forward and tend to be conservative by 30 percent when it comes to predicting the hydraulic pressure needed to shear tubulars with MASP at the BOP.	BSEE disagrees with this comment and the Final Rule continues to require independent third-party verification. This requirement ensures that everyone will perform the calculations, not just prudent operators. Third-party verification provides additional and necessary assurance that the blind-shear rams will be able to shear the drill pipe at MASP. The additional requirements in this rulemaking are intended to support existing requirements and not replace them.
§ 250.416(f)	The reliability and operability of the BOP can be confirmed without bringing the entire BOP and Lower Marine Riser Package (LMRP) to surface after each well, by visual inspection of a subsea BOP with an ROV and through a thorough function and pressure testing process. Any regulation that would require the operator to pull the stack to surface, handle the riser, and re-run it introduces more risk to personnel, well bore, and equipment. The proposed new API RP–53, 4th Edition, states: "Section 18.2 Types of Tests. This section addresses the types of tests to be performed and the frequency of when those tests are to be performed, realizing that the BOP can be moved from well-to-well without returning to surface for inspections and testing. For those cases, a visual inspection (by ROV) should be performed. Operability and integrity can be confirmed by function and pressure testing. In these instances, subsequent testing criteria shall apply for testing parameters." This approach is safer and the regulation must be amended.	BSEE disagrees. The operator must pull the BOP stack to surface and complete a between-well inspection. The required inspection is more thorough than a visual inspection by an ROV and will help ensure the integrity of the BOP stack. As required in § 250.446(a), a between well inspection must be performed according to currently incorporated API RP 53, sections 17.10 and 18.10, Inspections. The stump test of the subsea BOP before installation was already required under § 250.449(b) as it existed before promulgation of the IFR. To conduct a stump test, the BOP must be located on the surface. The BOP inspection was a recommendation in the Safety Measures Report.
§ 250.416(f)	30 CFR 250.416(f) requires that an independent third-party verify that a subsea BOP stack is fit for purpose. Section 250.416(f)(2) further requires that the subsea BOP stack has not been compromised or damaged from previous service—no guidance is given on how one is to determine that the subsea BOP hasn't been compromised or damaged. For multi-well projects where it makes senses to hop the BOP stack from well to well, would a successful subsea function test and pressure test be sufficient evidence that the requirement has been met?.	BSEE does not specify how the third-party verifies that the BOP has not been compromised or damaged from previous service. As required in § 250.446(a), a between-well inspection must be performed according to API RP 53, sections 17.10 and 18.10, Inspections. The requirement to conduct a stump test of the subsea BOP before installation existed before promulgation of the IFR, under § 250.449(b). The operator may not hop the BOP stack from well to well and be in compliance with the new provisions of this section or the previously existing requirements under § 250.449(b).
§ 250.416(f)(2)	This requirement infers that an inspection of the BOP system is required to ensure the system has not been compromised or damaged from previous service. Please confirm that the agency agrees that a subsea BOP system is not compromised or damaged provided it can be function tested and pressure tested in the subsea environment where it will be in operation. Standardized pressure testing in the subsea environment without visual inspection fulfills the requirements of § 250.416(f)(2).	In § 250.416(f)(2), BSEE does not specify how the third-party verifies that the BOP has not been compromised or damaged from previous service. However, BSEE has requirements for between-well inspections in § 250.446(a), and stump testing prior to installation in § 250.449(b).
§ 250.416(f)(2)	If it is mandated that a visual inspection between wells is required then the cost to implement of $1.2 MM is grossly understated. The cost to pull a BOP for a visual inspection is underestimated. The cost of pulling a subsea BOP for a visual inspection would result in a $5–$15 million opportunity cost.	The full cost to pull a subsea BOP to the surface following an activation of a shear ram or lower marine riser package (LMRP) disconnect (under § 250.451(i)) in the benefit-cost analysis is estimated to be $11.9 million dollars. This amount is within the range suggested by the commenter. However, the requirement to conduct a visual inspection and test the subsea BOP between wells predated the IFR and was in the previously existing regulation at § 250.446(a). Because this requirement is not a new provision, no compliance costs are assigned in the economic analysis.
§ 250.416(f)(2)	Third-party verification that the BOP stack has not been compromised or damaged from previous service can be accomplished by successful subsea function and pressure tests without visual inspection. Between well visual inspections of the BOP internal components is not required.	An independent third-party must confirm that the BOP stack matches the drawings and will operate according to the design. The third-party verification must include 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;

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
		(3) The BOP stack will operate in the conditions in which it will be used. BSEE does not specify how the third-party verifies that the BOP has not been compromised or damaged from previous service. However, BSEE has requirements for between-well inspections in § 250.446(a), and stump testing prior to installation in § 250.449(b).
§ 250.416(g) Qualification for Independent Third Parties.	The requirements for independent third parties to conduct BOP inspections fail to provide globally consistent standards necessary for the lifecycle use of Mobile Offshore Drilling Units (MODUs) on a global basis. The Interim Rule allows for an API licensed manufacturing, inspection, certification firm; or licensed engineering firm to carry out independent third-party verification of the BOP system, as well as technical classification societies. We recommend that the Interim Rule be amended to only enable organizations with the necessary breadth and depth of engineering knowledge, and experience and global reach, and demonstrable freedom from any conflict of interest, such as classification societies, can qualify as 'independent third parties'. We believe that owing to the global employment of MODUs, where rigs could be engaged anywhere around the world, only independent technical classification societies have the global reach to ensure consistency in inspection and verification of safety critical equipment necessary to ensure the safe operation of an asset throughout its lifecycle.	In response to comments, BSEE removed the option for the independent third-party to be an API-licensed manufacturing, inspection, or certification firm in § 250.416(g)(1) because API does not license such firms. Section 250.416(g)(1) allows registered professional engineers, or a technical classification society, or licensed professional engineering firms to provide the independent third-party verification. Section 250.416(g)(2)(i) requires the operator to submit evidence that the registered professional engineers, or a technical classification society, or licensed professional engineering firms or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform verifications. BSEE may accept the verification from any firm or person that meets these requirements. We will not require the exclusive use of technical classification societies at this time.
§ 250.420(a)(6)	Certification by a professional engineer that there are two independent tested barriers and that the casing and cementing design are appropriate.	The comment supports the requirements in the IFR. However, BSEE clarified the requirement for the two independent barriers, based on other comments.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h).	What is the definition of well-completion activities? This is the first time it has been mentioned that barriers had to be certified by a professional engineer, only casing design and cementing were mentioned in the past.	BSEE clarified the certification requirement in § 250.420(a)(6) by removing the term ''well-completion activities,'' because it was redundant in the context of that provision. The two required barriers are part of the casing and cementing design.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h).	Will BOEMRE still check casing designs based on load cases that are not published? If so, will certified plans be rejected due to design reviews within the agency? Will Agency design reviews be done by Registered Professional Engineers (RPE)? If not, what will be the process for approval when an RPE approved design conflicts with the Agency? Will the Agency mandate a change and take the responsibility for that change?	There are multiple ways to calculate the load cases. The operator must ensure the well design and calculations are appropriate for the purpose for which it is intended under expected wellbore conditions. BSEE engineers will conduct the design reviews. Any issues will be resolved with the operator on a case-by-case basis.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h) Professional Engineer.	Liabilities that will be placed onto a ''Professional Engineer'' are an issue. The PE approach demands that the PE is intimately involved in all aspects of the design and also in primary communication as the well is drilled and small variations in the plan are made or happen. All liability for the well must remain with the operator without any ''dilution'' to a PE, although review by a PE or other ''independent and reputable'' third-party is totally appropriate.	The intent of the PE certification is to ensure that all plans are consistent with standard engineering practices. To add to safety assurances, BSEE included language in § 250.420(a)(6) that the Professional Engineer be involved in the design process. Such person must be included in the design process so that he or she is familiar enough with the final design to make the required certification. Under § 250.146(c), persons actually performing an activity on a lease to which a regulatory obligation applies are jointly and severally responsible for compliance. Such third person responsibility does not eliminate or dilute the operator's responsibilities for a well.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h) Professional Engineer.	Can the required ''registered professional engineer'' be a company employee?	Yes, the registered professional engineer can be a company employee.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h) Professional Engineer.	Require that all certifications needed by a Registered Professional Engineer be done by a Registered Professional Petroleum Engineer. It makes no sense at all to utilize any PE. If so, at least require a BS in Petroleum Engineering. There is no specification to determine how any Registered Professional Engineer is ''capable of reviewing and certifying that the * * * is appropriate for the purpose for which it is intended under expected wellbore conditions.''	BSEE disagrees that the professional engineer must be a petroleum engineer; a professional engineer with another background who has expertise and experience in well design will be capable of certifying these plans. The expectation is that a licensed professional engineer will NOT certify anything outside of their area of expertise. However, in response to the commenter's concern, this Final Rule adds an expertise and experience requirement for the person performing the certification.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h).	The intent of Congress and the Act does not appear to be complied with by the proposed rule. The use of a registered Professional Engineer to certify casing and cementing programs when "The Registered Professional Engineer must be registered in a State of the United States but does not have to be a specific discipline" does not appear to comply with the allowance for coordination with local Coastal Affected Zone States to have input. Two deficiencies are apparent. One is a licensed professional engineer should not be certifying anything that he is not competent to certify due to his education, training and experience. The second is that the engineer should be licensed in the Coastal Zone Affected State due to the differences that occur in licensing requirements. Some states are more liberal than others in the exemptions allowed and the requirements for discipline specific engineering licensure. If Texas wants to allow a higher risk then Texas offshore Coastal Affected Zones should be the only zones that are allowed to have such higher risk to be taken. If Louisiana or Mississippi want to be more restrictive then their offshore waters should be more restrictive. This seems to be the intent of the Coastal Zone Affected State language in the federal statutes. As currently proposed a licensed engineer from the state of minimum requirements can be selected.	The certification requirement is intended to ensure that all operators meet basic standards for their cement and casing. This requirement for PE certification is a substantial improvement compared to previous rules in which a certification was not mandatory. The final rule has added a provision to assure that a licensed professional will NOT certify anything outside of his or her area of expertise and experience. Because OCS projects occur offshore from several states, a company may want to use the same PE regardless of the location of any given well. Furthermore, the certification requirement applies uniformly to any project in Federal waters. Under these conditions, the certification standard combined with the liabilities associated with certification of a plan effectively address certification concerns. Also, States with approved coastal management programs have adequate opportunities to express their concerns about specific projects under other provisions of the regulations.
§§ 250.420(a)(6), 250.1712(g), and 250.1721(h).	BOEMRE now requires a Registered Professional Engineer to certify a number of well design aspects including: casing and cementing design, independent well barriers, and abandonment design. This is a new, important requirement. BOEMRE does not, however, require that the engineer be certified as a Registered Professional Engineer in any particular engineering discipline. This creates the possibility that a Professional Engineer, with little or no experience with oil and gas well design, drilling operations or well pressure control could be certifying these designs. For example, BOEMRE's rule would allow an electrical engineer to certify a well design that may have no expertise or experience on offshore well construction design. We recommend that the Registered Professional Engineer requirement be limited to the discipline of Petroleum Engineering, and/or a Registered Professional Engineer in any engineering discipline that has more years of experience designing and drilling offshore wells. We agree that Registered Professional Engineers have the technical capability to assimilate the knowledge to certify well construction methods over a period of time, but only the Registered Professional Petroleum Engineer is actually tested on well casing, cementing, barriers and other well construction design and safety issues. Other engineering disciplines require on-the-job training and experience to expand their expertise and apply their engineering credentials to offshore well construction design certification.	BSEE disagrees that the professional engineer must be a petroleum engineer; a professional engineer with another background who has experience in well design will be capable of certifying these plans. In response to commenters' concerns, we have added an expertise and experience requirement for the certifying person. It is the operator's responsibility to ensure that the Registered Professional Engineer is qualified and competent to perform the work and has the necessary expertise and experience. The expectation is that a licensed professional engineer will NOT certify anything outside of his or her area of expertise. The operator certainly has a strong incentive to assure that the professional engineer is competent because the operator is responsible for the activities on the lease and the consequences thereof.
§ 250.420(a)(6)	30 CFR 250.420(a)(6) requires that a Registered Professional Engineer certify barriers across each flow path and that a well's casing and cementing design is fit for its intended purpose under expected wellbore conditions. There are RPE's whose area of expertise isn't well design or construction. There are very few drilling and completion engineers with both sufficient expertise to make the required assessment and a PE license. What in this requirement makes operations in the GoM safer? Does BOEMRE plan to consider changing this requirement to expand the number of truly qualified people who can accurately assess this situation? What will eventually be the right standard for the certifying authority?	Requiring a Registered Professional Engineer's certification helps to ensure that the casing and cementing design meets accepted industry design standards. The expectation is that licensed professional engineers will NOT certify anything outside of their area of expertise. In response to this comment, this Final Rule does expand the persons who can make the required certification if they are registered and have the requisite expertise and experience.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§§ 250.420(a)(6), 250.1712(g) and 250.1721(h).	The description of "flow path" would be improved by commenting on examples and/or by providing a definition and not including potential paths, i.e., previously verified or tested mechanical barriers are accepted without retest. Flow paths in the broadest terms would include annular seal assemblies which may not be accessible on existing wells. The assumption that all casing strings can be cut and pulled would result in exceptions in the majority of cases and would introduce a health and safety risk to operating personnel and equipment currently not present.	BSEE revised the regulatory text in § 250.420(b)(3) to include an example of barriers for the annular flow path and for the final casing string or liner. Once an operator performs a negative test on a barrier, the operator does not have to retest it unless that barrier is altered or modified. Also, see the subsequent comment responses that address the flow paths to which the barrier requirements apply.
§ 250.420(a)(6)	Will BOEMRE still check casing designs based on load cases that are not published? If so, will certified plans be rejected due to design reviews within the agency?	BSEE engineers will check casing designs. BSEE will resolve any differences with the operator on a case-by-case basis.
§ 250.420(a)(6)	BOEMRE has not provided specific guidance on what aspects of casing and cementing designs must be initially certified or guidance on triggers which would cause a plan to be recertified for continuance of operations. The Offshore Operators' Committee OOC provided those triggers to BOEMRE on October 12, 2010, and requests they be accepted as the only triggers for plan certification. Currently, the BOEMRE is inconsistent in their requests for recertification and fearful of approving minor changes that have no effect on safety. Further, delays to operations resulting in additional operational exposure and safety risk are to be expected when the Agency requires arbitrary recertification when simple changes are required. The requirement for an RPE review for OCS operations may become a bottleneck if this requirement becomes a standard for all U.S. operations.	While the list provided by the commenter contained some good examples, it is not comprehensive. If an activity triggers the need for a revised permit or an APM, then the Registered Professional Engineer must recertify the design. BSEE is working to improve consistency among the District Offices.
§ 250.420(b)(3)	Add clarification to the dual mechanical barrier requirement to ensure the barriers are installed within the casing string and does not apply to mechanical barriers that seal the annulus between casings or between casing and wellhead. Acceptable barriers for annuli shall include at least one mechanical barrier in the wellhead and cement across and above hydrocarbon zones. Placement of cement can be validated by return volume, hydrostatic lift pressure or cased hole logging methods. Industry best practices do not consider dual float valves to be two separate mechanical barriers because they cannot be tested independently and because they are not designed to be gas-tight barriers. This regulation does not achieve the safety objectives of the Drilling Safety Rule	In response, this Final Rule revises § 250.420(b)(3) to provide that for the final casing string (or liner if it is the final string), an operator must install one mechanical barrier, in addition to cement, to prevent flow in the event of a failure in the cement. In response to the comment, we also clarify that a dual float valve, by itself, is not considered a mechanical barrier. The appropriate BSEE District Manager may approve alternatives.
§ 250.420(b)(3)	Does the dual mechanical barrier requirement apply to just the inside of the casing or to both the inside and annulus flow paths? Our interpretation is the inside of the casing. It is also not clear when these dual barriers are required.	BSEE revised the regulatory text at § 250.420(b)(3) to clarify the requirement that two independent barriers are required in each annular flow path (examples include, but are not limited to, primary cement job and seal assembly) and for the final casing string or liner. The appropriate BSEE District Manager may approve alternatives.
§§ 250.420(b)(3), 250.1712(g) and 250.1721(h).	The incorporation by reference of API RP 65–2 in § 250.415(f) includes a definition of a mechanical barrier. This either confuses or contradicts the use of the phrase "mechanical barrier" in sections §§ 250.420(b)(3), 250.1712(g) and 250.1712(h). The description of a "seal achieved by mechanical means between two casing strings or a casing string and the borehole" would not be possible regarding an existing well, specifically for the temporary or permanent abandonment, and does not include seals that are not in an annulus. Question: Do cast iron bridge plugs and retainers/packers without tubing installed meet the requirement for mechanical barriers?	BSEE revised the language in § 250.420(b)(3) to clarify that the operator must install two independent barriers to prevent flow in the event of a failure in the cement, and clarified that a dual float valve is not considered a barrier. The appropriate BSEE District Manager may approve alternative options. BSEE revised the language in §§ 250.1712 and 250.1721 to clarify the requirements. For wells being permanently abandoned and wellhead removed, the PE needs to certify that there are two independent barriers in the center wellbore and the annuli are isolated per the regulations at § 250.1715. If the wellhead is being left in place for the production string, the registered PE must certify two independent barriers in the center wellbore and the annuli. The registered PE may not certify work that was previously performed; the registered PE must only certify the work to be performed under the permit submitted. A cast iron bridge plug is an option as a mechanical barrier. With regard to the question of using retainers/packers to meet the requirement for mechanical barriers, evaluation will be conducted on a case-by-case basis.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.420(b)(3)	The rules seem to encourage use of devices described in Section 3 of RP 65, some of which have never been used in deepwater and are in fact of dubious utility. It is agreed that more stringent cementing practices are in order, but these proposed rules are too confusing to serve this purpose. This section needs to be revisited and specific, practical, recommended practices set out.	BSEE revised this section in the Final Rule to clarify the requirement of two independent barriers, and also clarified that a dual float valve is not considered a mechanical barrier. The BSEE District Manager may approve alternatives.
§ 250.420(c)	30 CFR 250.420(c) requires that cement attain 500 psi compressive strength prior to drill out. What drives the CS requirement? It's not API RP 65–2.	This is a previously existing requirement and therefore not within the scope of this rulemaking.
§§ 250.420, 250.1712, and 250.1721	Previous guidance/interpretation issued by BOEMRE said that deviation from certified procedures required contact with the appropriate BSEE District Manager. This is documented only in the guidance and is not implicit in this part of the rule. We request that BOEMRE specify the kinds of variances that require this contact.	If an activity triggers the need for a revised permit or an APM, then the Registered Professional Engineer must recertify the design and the revised permit or Application for Permit Modification (APM) must receive approval from the appropriate BSEE District Manager.
§ 250.423(b)	Need definition or clarity around the term—lock down and the requirement for locking down a drilling liner. Must all liner hangers have hold down slips? Normally conventional line hangers only have hang off slips to transfer the weight of the liner to the previous casing string. Once the seal is energized for a Liner Top Packer, it will hold pressure from below and above, but not all seals have slips to prevent uplift should the pressure-area effect exceed the weight of the liner. Requiring hold down slips on a conventional liner hanger increases the difficulty to fish the liner out of the hole, in fact it will lead to a milling operation.	BSEE has revised the language in § 250.423(b), to clarify that the Final Rule does not require the use of a latching or lock down mechanism for a liner. However, if a liner is used that has a latching or lock down mechanism, then that mechanism must be engaged.
§ 250.423(b)	As currently drafted, § 250.423(b) requires negative testing to be set to either 70 percent of system collapse resistance pressure, saltwater gradient, or 500 psi less than formation pressure, whichever is less. The rule implies that operators are required to perform a test on the casing seal; however, the industry has had several examples of where testing to a salt water gradient to sea floor has caused casing collapse in deep wells with casing across the salt. This regulation does not clearly state whether it applies to casing shoe extensions, such as expandable casing or 18'' (which is a surface casing shoe extension). Since not all casing sizes (e.g. 16'' and 18'') have lockdown mechanisms at this time, the rule should allow for waivers to this requirement until such time that lockdown mechanisms are available.	BSEE revised the language for the requirements for a negative test under § 250.423(c). The operator must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems to ensure proper casing or liner installation. You must perform the negative test to the same degree of the expected pressure once the BOP is disconnected. BSEE also revised the language for the requirement to ensure proper installation of the casing in the subsea wellhead and liner in the liner hanger in § 250.423(b). Regarding lockdown mechanisms, see previous comment.
§ 250.423(b)	The operator must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. The operator must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string or liner. Performance and documentation of a pressure test on the casing seal assembly to ensure proper installation of the casing and the liner are essential. Documentation that the latching mechanisms or lock down mechanisms are fully engaged upon installation of each casing string or liner must be mandatory.	BSEE agrees with this comment. Section 250.423(b) requires performance of a pressure test on the casing seal assembly and further requires the operator to maintain the necessary documentation.
§ 250.423(b)(1)	Not clear if integral latching capability of casing hanger/seal assembly is acceptable or if a separate mechanism is required.	Under § 250.423(b)(1), the operator must ensure proper installation of casing in the subsea wellhead by ensuring that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string. The rule does not require a specific type of latching mechanism. Integral latching capability of the casing hanger or seal assembly is acceptable.
§ 250.423(c)	What is the design basis and acceptance criteria required for negative testing?	The regulations do not specify a particular design basis for the negative pressure test. Under § 250.423(c)(3) operators must submit negative test procedures and provide their criteria for a successful test to BSEE for approval. BSEE revised the language of § 250.423(c)(5) to include examples of indications of failure.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.423(c)	It is imperative that the operator establish what is ''normal'' for this type of testing event, such that the rig crew is in no doubt as to what to look for and whether or not there is an event going on which is ''not normal''.	Operators are required to submit the procedures of these tests and provide their criteria for a successful test with their APD. BSEE revised the regulatory text to include examples of indications of a failed negative pressure test.
§ 250.423(c)	What is the definition of intermediate casing? The rule states a negative pressure test is required for intermediate and production casing. If drilling liners are set below intermediate casing is additional negative testing required? The intent of this requirement is not clear. The magnitude of the negative test is also not apparent. Is the intent to test the entire casing, wellhead, liner top, or the shoe? Surface wellheads are negative tested for each BOP test when the stack is drained and water is used for a test. If a negative test of an intermediate shoe is intended, then, what is the purpose since the casing shoe will be drilled out. In general, negative testing should not apply to all wells and should apply if the load is anticipated and then not until such time it is needed.	BSEE revised § 250.423(c) to clarify the requirements for the negative pressure test. Intermediate casing is any casing string between the surface casing string and production casing string. We revised the Final Rule to require negative pressure tests only on subsea BOP stack and wells with mudline suspension systems. We specifically require the operator to perform a negative pressure test on the final casing string or liner, and prior to unlatching the BOP at any point in the well (if the operator has not already performed the negative test on its final casing string or liner). At a minimum, the negative test must be conducted on those components that will be exposed to the negative differential pressure that will occur when the BOP is disconnected. The intent of the requirement is to ensure that the casing can withstand the wellbore conditions. The Final Rule addresses indicators of failed pressure tests and specifies what the operator must do in the event of a failed test.
§ 250.423(c)	Wells with surface wellheads should be exempt from negative tests unless the well is to be displaced to a fluid less than pore pressure and in that case the shoe, productive intervals, and liner tops can be negative tested to the amount anticipated prior to or during the displacement. The requirement to negative test wells with surface wellheads should not be mandated since the well can be displaced to a fluid less than pore pressure under controlled conditions without risk of an influx getting in a riser.	We agree that as a general matter wells with surface well heads should be exempt from negative pressure tests and we revised the Final Rule to require the negative pressure test only for wells that use a subsea BOP stack or wells with mudline suspension systems. We did, however, provide that if circumstances warrant, the BSEE District Manager may require an operator 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.
§ 250.423(c)	Additional guidance given by BOEMRE has indicated a desire to negative test all liner tops exposed in either the intermediate or production annulus on all wells with surface BOP equipment. This requirement is not consistent with the desire to improve safety since many liner tops are never exposed to negative pressures during the life of the well. Thus performing the test exposes personnel to additional exposure while tripping pipe to perform the test, risks the well by installing non-drillable test packers above the liner top during the test, and will expose personnel to additional material handling requirements.	All liner tops, exposed below the intermediate casing (wells with mudline suspension systems) must be tested, but only for wells with subsea BOP stacks or wells with mudline suspension systems. The test must be performed before displacing kill weight fluids in preparation for disconnecting the BOP stack.
§ 250.423(c)	The Agency has not provided guidance on when the test is to be performed. Testing upon installation is not advisable due to additional pressure cycles applied to the cement early in the development of its strength that could result in premature cement failure. Additionally, if a negative load is anticipated during operations, it is best to defer the negative test to assure well integrity is validated just prior to the intended operation.	This Final Rule revises § 250.423(c) to state that the negative pressure test must be performed on the final casing string or liner, and prior to unlatching the BOP at any point in the well. The negative test must be conducted on those components, at a minimum, that will be exposed to the negative differential pressure that will be seen when the BOP is disconnected.
§ 250.423(c)	Negative testing should be performed on subsea wells and wells with mudline suspension systems where it is important to validate barriers prior to removal of mud hydrostatic pressure during an abandonment or suspension activity such as hurricane evacuation or BOP repair. Drilling or production liner tops should not require negative testing upon installation. Testing should be deferred until just prior to performing an operation where a negative load is anticipated on a liner top or wellhead hanger.	BSEE agrees with the comment. We revised § 250.423(c) to require the negative pressure tests only on wells that use a subsea BOP stack or wells with mudline suspension systems. See the response to the previous comment.
§ 250.423(c)	The magnitude and duration of an acceptable negative test should be provided for consistency. Recommend negative tests on subsea wells to be equal to SWHP at the wellhead.	We revised the Final Rule to require the negative test be performed to the same degree of the expected pressure once the BOP is disconnected.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.423(c)	30 CFR 250.423(c) requires negative testing of intermediate casing and liner tops, but offers no guidance as to the magnitude of the required negative test. As an experienced deepwater driller, I've assumed that BOEMRE meant for this testing to apply to intermediate casing string seal assemblies on subsea wells. That mimics what the well would see in a BOP stack disconnect situation. I see no valid reason to be negatively testing intermediate casing shoes that will be subsequently drilled out. I'd also like to understand the rationale behind a negative test on all liner tops. Just because a liner top tests negatively doesn't mean it won't fail if the well is exposed to a differential as a result of a blow out. I see a negative test on production liner tops as a prudent thing, but this type testing of drilling liners that will ultimately be covered up can increase risk in certain situations (small platform rig on a floating facility with limited pit space could get into an unintended well-control situation dealing with the fluid handling/movements required by a negative test).	BSEE agrees. We revised this requirement to require the negative pressure tests only on wells that use a subsea BOP stack or wells with mudline suspension systems. See the response to the previous comments.
§ 250.442	Must heavy weight drill pipe be shearable with blind shear rams?	Blind-shear rams must be capable of shearing any drill pipe in the hole under maximum anticipated surface pressure, including heavyweight drillpipe. This Final Rule revises § 250.416(e) to include workstring and tubing to clarify that these are also considered drill pipe and need to be shearable by the blind-shear rams.
§ 250.442	What does ''operable'' mean for dual pod controls? Does it mean 100 percent functional and redundant?	The provision under § 250.442(b), for an ''operable dual-pod control system'' was an existing requirement and was included in the IFR because that section was rearranged into a table to accommodate the new provisions. The meaning of ''operable dual-pod control system'' has not changed. The commenter is correct in that these are redundant systems. Each pod has to be independent of the other and 100 percent functional.
§ 250.442	In § 250.442(c), what does ''fast'' mean for subsea closure and what are the ''critical'' functions?	As specified in § 250.442(c), the accumulator system must meet or exceed the requirements in API RP 53, section 13.3, Accumulator Volumetric Capacity.
§ 250.442	What will be competency basis for qualification of an individual to operate the BOP's?	The operator must ensure that all employees and contract personnel can properly perform their duties, as required under § 250.1501. Section 250.442(j) prescribes training and knowledge requirements for persons authorized to operate critical BOP equipment.
§§ 250.442(d), § 250.515(e), and § 250.615(e)	While the verified ability to close one set of pipe rams, close one set of blind-shear rams, and unlatch the lower marine riser package using a Remotely Operated Underwater Vehicle (ROV) is critical, the time delay associated with launch and subsea deployment of an ROV will likely have enabled the full force of a major blowout to already clear the well bore and result in excessive pressures and a debris stream at the BOP that can complicate efforts to shut in the well. Preventive and precautionary measures are a priority, and immediate shut-in capability will always be more critical than after-the-fact ROV response; thus this initiative should go further toward ensuring more immediate wild well shut-in capabilities, either in the current rulemaking, or in a future rulemaking.	We agree that there is a time delay associated with the launch and deployment of an ROV and that preventative and precautionary measures are a priority and immediate shut-in capability is critical. The intent of the provision is to ensure that an ROV is available in the unlikely event that all other measures fail. This regulation is intended to address broad issues related to well-control; BSEE is planning future regulations that will focus on preventative measures and improving immediate response capabilities.
§§ 250.442(e), 250.515(e), and 250.615(e)	The ROV crews should not be required on a continuous basis, this item needs to be revised to reflect the need for having a trained ROV crew on board only when the BOP is deployed.	BSEE agrees with the substance of this comment and has revised § 250.442(e) accordingly.
§ 250.442(j)	What is meant by operate critical BOP equipment, maintenance, or activation of equipment?	Section 250.442(j) establishes minimum requirements for personnel who operate any BOP equipment. The paragraph expressly refers to BOP hardware and control systems. In addition, other paragraphs of § 250.442 refer to specific features of the BOP and associated equipment. Any person authorized to operate or maintain any of the BOP components or systems must satisfy the requisite training and knowledge requirements.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§§ 250.446(a), 250.516(h), 250.516(g), and 250.617 (Section numbers refer to the IFR.).	The recordkeeping requested should be a responsibility of the drilling contractor. Many operations are short lived contracts and once the rig is released, the contractor has no obligation to ensure the records remain on the rig. Drilling contractors should be required to have a BOPE certification program complete with a certificate of compliance that is renewed every 3 to 5 years by a certification agency or class society. This will assure drilling contractors maintain their equipment to a higher standard on a routine basis. Certification documents for rental BOPE would also be used by the operator or contractor depending upon who is renting the equipment.	Under § 250.146(c), lessees, operators, and persons performing an activity subject to regulatory requirements are jointly and severally responsible for complying with regulatory requirements. This includes contractors maintaining and inspecting BOP systems. See the discussion in the section-by-section portion of this preamble.
§§ 250.446(a), 250.516(h), 250.516(g), and 250.617 (Section numbers refer to the IFR.).	We believe that API-recommended practices have not proven to be a standard that has generated full and verifiable compliance by all. Require documentation of BOP inspections and maintenance according to API RP 53. The codification of API-recommended practices via Federal regulations will be needed to ensure reliable compliance going forward. This should take place in the current rule, or, at a minimum, in a future rule.	BSEE already requires operators to follow Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells. We continually review standards and our use of these standards. We may consider additional documentation from operators in future rulemaking.
§ 250.449(h)	Are the requirements for function test for normal or high pressure function or both? In § 250.449(h), request change from the required duration from 7 days to 14 days. The basis for this is to mitigate the risk and exposure due to the additional tripping of pipe out of hole in order to function test blind/shear rams.	Section 250.449(h) is a previously existing requirement that was included in the IFR only to make editorial changes to accommodate new requirements in subsequent paragraphs. The requested revision is outside the scope of this rulemaking.
§§ 250.449(j), 250.516(d)(8) (Section numbers refer to the IFR.).	Stump test ROV intervention functions .... This does not go far enough. This is insufficient. It is necessary that the BOP ROV functions be regularly tested at the seabed with the ROV that would be used in an emergency. The only requirement of the stump test should be to test the plumbing. The BOP ROV functions should be tested at each BOP test when at operating hydrostatic pressures and temperatures.	Section 250.449(j) requires the operator must test one set of rams during the initial test on the seafloor. In this Final Rule, we added that the test of the one set of rams on the seafloor must be done through an ROV hot stab to ensure the functioning of the hot stab. BSEE may consider additional requirements in future rulemaking.
§ 250.449(k)	Section 250.449(k) explains: "[f]unction test auto shear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system during the initial test on the seafloor." We do not recommend testing the deadman system when the stack is attached to a subsea wellhead. If the rig experiences a dynamic positioning incident, i.e., a drive-off or drift-off during the test, the only alternative system available to disconnect from the wellhead is the ROV intervention system. Failure to disconnect in time could result in serious damage to the rig equipment, the well head, or the well casing. As an alternative, we believe it would be more appropriate to test the autoshear system subsea. Such a requirement will test the same hydraulic system as the deadman, however, the autoshear function does not disable the control system and create the same well and equipment hazards as testing the deadman system.	BSEE believes that not testing the deadman system is a greater risk than conducting the test. Testing the deadman system on the seafloor is necessary to ensure that the deadman system will function in the event of a loss of power/hydraulics between the rig and the BOP. To help mitigate risk for the function test of the deadman system during the initial test on the seafloor, we added that there must be an ROV on bottom, so it would be available to disconnect the LMRP should the rig experience a loss of stationkeeping event. We also added clarifications for the required submittals of procedures for the autoshear and deadman function testing, including procedures on how the ROV will be utilized during testing.

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.449(k)	*Modify deadman system testing requirements to increase safety.* As drafted, operators must test the deadman system during the initial test on the seafloor. Intentionally disabling the deadman system increases the risk to personnel, well bore and equipment should a ''power management'' or ''loss of station keeping'' incident occur during a deadman system test. Testing of the deadman system requires shutting down of power and hydraulic systems to the BOP thereby eliminating the ability to disconnect in a controlled manner should a ''power management'' or ''loss of station keeping'' incident occur. As a result, rig personnel could be exposed to the consequences of a violent release of tension if a riser component fails and seafloor architecture will be exposed to released/dropped riser components. Revise the deadman system testing requirement, bringing it in line with the proposed new API RP–53, 4th Edition recommendations. Specifically, testing should be completed during commissioning, rig acceptance and if any modifications or maintenance has been performed on the system, not to exceed 5 years.	BSEE believes that not testing the deadman system is a greater risk than conducting the test. Testing the deadman system on the seafloor is necessary to ensure that the deadman system will function in the event of a loss power/hydraulics between the rig and the BOP. To help mitigate risk for the function test of the deadman system during the initial test on the seafloor, we added that there must be an ROV on bottom, so it would be available to disconnect the LMRP should the rig experience a loss of stationkeeping event. We also added clarifications for the required submittals of procedures for the autoshear and deadman function testing, including procedures on how the ROV will be utilized during testing. BSEE will review API RP–53, 4th Edition, and decide if it is appropriate for incorporation, after it is finalized.
§§ 250.449(k), 250.516(d)(9), 250.616(h)(2) (Section numbers refer to the IFR.).	We recommend testing the deadman system when attached to a well subsea upon commissioning or within 5 years of previous test but not at every well. If during the testing time the rig experiences a dynamic position incident, i.e., a drive off or drift off, the only options to disconnect from the well are acoustically (if acoustic system fitted), or with an ROV. Failure to disconnect in time could result in serious equipment damage, and/or damage to the well head.	BSEE believes that not testing the deadman system is a greater risk than conducting the test. Testing the deadman system on the seafloor is necessary to ensure that the deadman system will function in the event of a loss power/hydraulics between the rig and the BOP. To help mitigate risk for the function test of the deadman system during the initial test on the seafloor, we added that there must be an ROV on bottom, so it would be available to disconnect the LMRP should the rig experience a loss of stationkeeping event. We also added clarifications for the required submittals of procedures for the autoshear and deadman function testing, including procedures on how the ROV will be utilized during testing.
§§ 250.449(k) and 250.516(d)(9) (Section numbers refer to the IFR.).	Stump test the autoshear and deadman. Test the deadman after initial landing. Both the deadman and autoshear should be tested on the seabed. Moreover the Deadman should include a disconnect function. However, the LMRP connector should not be unlocked during this test. Rather, the LMRP disconnect function should be plumbed in such a way that during the test the fluid can be vented to sea rather than to the unlatch side.	On the initial test on the seafloor, the operator is required only to test the deadman system. The rule requires operators to submit their test procedures with the APD or APM for approval. BSEE may develop specific test procedures at a later time.
§ 250.451(i)	A successful seafloor pressure and function test of the BOP following a well-control event also is an acceptable means of verifying integrity. Ram sealing elements would be compromised before damage to the rams themselves would be extensive enough to prevent successful shearing of pipe. Additionally, plugging an open hole that may be experiencing ballooning and gas following a well-control event and pulling the BOP and riser present safety and operational risks that are likely much greater than proceeding with the drilling program using a fully tested BOP stack.	After a well-control event where pipe or casing was sheared, a full inspection and pressure test assures that the BOP stack is fully operable. The rule requires the operator to do this only after the situation is fully controlled.
§ 250.451(i)	We believe § 250.451(i) is best read to only require a subsea BOP stack to surface when pipe is sheared, rather than actuated on an empty cavity. We request that the agency clarify that the requirement to pull a subsea BOP stack to surface after actuating the blind shear rams does not apply when the blind shear rams are actuated on an empty cavity, but applies when pipe is sheared.	BSEE agrees with the comment that § 250.451(i) does not apply to actuation of shear rams on an empty cavity. Section 250.451(i) states that an operator must retrieve the BOP if: ''You activate the blind-shear rams or casing shear rams during a well-control situation, in which pipe or casing is sheared.''

TABLE 1—SPECIFIC SECTIONS COMMENTS AND RESPONSES—Continued

Section—topic	Comment	BSEE response
§ 250.456(j)	Does this requirement only refer to the end of well during abandonment or at any time during the drilling of a well? There are times when mud weight is cut prior to drilling out a casing shoe due to exposure of weak formations or anticipated lost circulation. Would approval be required to cut mud weight in these circumstances? Consider that mud weight is cut just prior to drilling out the shoe in a controlled environment at which time the entire system is negative tested with pipe in the hole at TD and BOPs are capable of shutting in the well if and when needed.	This Final Rule revises § 250.456(j) to clarify that this requirement applies any time kill-weight mud is displaced, putting the wellbore in an underbalanced state. If the mud weight is cut, but the wellbore will remain in an overbalanced state, then approval is not required.
§§ 250.515 and 250.616	It appears that some of the requirements of NTL 2010–N05 which applied to workover BOPs have been omitted in the revision to 30 CFR 250.5XX and 250.6XX. Specifically, verification that the blind/shear is capable of shearing all pipe in the well at MASP has been omitted for workover and coiled tubing operations. Verification of this capability is as important in workover as it is in drilling, for both surface BOPs and subsurface BOPs. API RP 16ST, ''Coiled Tubing Well-control Equipment Systems'', Section 12, ''Well-control Equipment Testing'', should be referenced in 30 CFR 250.6XX in addition to the reference to API RP 53.	BSEE agrees that it is important for BOP requirements to be consistent, regardless of the application or stage of a well. These requirements should also apply to well-completion and well-workover activities. We changed the regulatory text in §§ 250.515 and 250.615 to reflect this. In addition, in response to the concern raised by the commenter, this Final Rule adds these requirements to subpart Q, since the same equipment used in drilling and workovers may be used in decommissioning operations, and similar safety risks also exist. BSEE may consider incorporating by reference API RP 16ST, ''Coiled Tubing Well-control Equipment Systems'' in future rulemaking.
§ 250.1503	What is the definition of enhanced deepwater well-control training? Will this require a new certification of well-control schools?	The rule does not use the phrase, ''enhanced deepwater well-control training.'' It does require deepwater well-control training for operations with a subsea BOP stack. The operator must ensure that all employees are properly trained for their duties as required in § 250.1501. BSEE expects that operators will integrate the deepwater well-control training requirement into their current subpart O well-control program.
§§ 250.1712(g), 250.1721(h), and 250.1715	Liabilities that will be placed onto a ''Professional Engineer (PE)'' are an issue. The PE approach demands that the PE is intimately involved in all aspects of the design and also in primary communication as the well is drilled and small variations in the plan are made or happen. All liability for the well must remain with the operator without any ''dilution'' to a PE, although review by a PE or other ''independent and reputable'' third-party is totally appropriate.	The operator is responsible for all activities on its lease, regardless of requirements for various persons to certify or verify various aspects of operations. Although persons performing certifications and verifications have responsibility for their actions, such responsibility will not eliminate or diminish the operator's responsibilities for compliance with applicable requirements.

TABLE 2—TOPICS AND GENERAL QUESTIONS COMMENTS AND RESPONSES

Topic	Comment	BSEE response
Participate in Standard Development	BOEMRE should participate in API's open process for adopting industry standards on an on-going basis.	BSEE agrees that its involvement in the standard development process with API and other standards organizations is important. We are already active in API's industry standard process and we are committed to continuing and increasing this involvement.
Participate in Standard Development	BOEMRE should participate in revising American Welding Society's (AWS) standards. AWS's standards committees comply with ANSI-approved procedures for standards development, which, among other things, guarantee public and open participation by any materially affected entity, committee interest group balance, fair voting, and written technical issue resolution. AWS solicits ongoing input and comments for these revisions from any interested party, including BOEMRE. BOEMRE's input to the standards committees would be invaluable to help understand the goals of the government and to apply AWS's experts' thoughtful consideration to ongoing regulatory issues. Moreover, participation in AWS standards-setting would provide BOEMRE with access to valuable scientific and technical expertise.	BSEE agrees that its involvement in the standard development process with AWS and other standards organizations is important. BSEE accepts this and other offers to participate in the development of standards that support the mission of BSEE.

TABLE 2—TOPICS AND GENERAL QUESTIONS COMMENTS AND RESPONSES—Continued

Topic	Comment	BSEE response
Subsea BOP Requirements	More work should be carried out in this area before final requirements are identified. In particular, the findings of the post-mortem on the Horizon BOP should be carefully looked at prior to a "final rule".	BSEE reviewed the findings of various DWH investigations before developing the Final Rule. Findings from the DWH investigation that are within the scope of this rulemaking were incorporated. BSEE will address other findings in future rules.
Blind-Shear Ram Redundancy Requirements	With this rule, BOEMRE has made the important first step of requiring independent third-party verification of blind shear ram capability, but deferred one of the most critical safety improvements, the requirement to install redundant blind-shear rams in each OCS BOP, to a later rulemaking process. We recommend that redundant blind-shear rams be required for all OCS drilling operations as of June 1, 2011.	BSEE is considering this requirement for future regulations. We do recognize the importance of having redundant safety features on BOP stacks. However, we need to consider all the impacts of such a requirement before requiring it by regulation. BSEE has concluded that the requirements of the IFR, as modified by this Final Rule, have enhanced operational safety sufficiently until such time that BSEE determines whether to add a requirement for additional blind-shear rams.
Accident Event Reporting	Also missing from the IFR is a requirement that OCS operators and their contractors report to BOEMRE any accidental event that could significantly impact well integrity or blowout prevention. This proposed reporting requirement includes, but is not limited to, any event where blowout preventer seal material may be compromised.	BSEE's incident reporting requirements are covered in §§ 250.187 through 250.190. Specifically, § 250.188(a)(3) requires the reporting of all losses of well-control, including uncontrolled flow of formation or other fluids; flow through a diverter; or uncontrolled flow resulting from a failure of surface equipment or procedures. We are looking into expanding the reporting requirements in future rulemaking.
Third-party Certifications	The rule makes repeated references to third-party "verification" of certain matters related to well-control equipment, including BOPs. The appropriate functional terminology should be "certification," rather than "verification." In industry practice, "certification" and "verification" are different functions. A party that "certifies" a process is different from the party that "verifies" the certified process is being followed. This is more than a definitional difference.	We disagree with the commenter's suggestion. The repeated use of the concept of independent third-party "verification" in § 250.416 and conforming provisions of the other subparts derives directly from various recommendations of the Department's May 10, 2010 Safety Measures Report, e.g., Safety Measures Report Recommendations I.A.2 and I.C.7 (pp. 20–21) that use the term "verification." The preparers of that report appear to have understood the distinction between "certification" and "verification" because in other recommendations the term "certification" is used, *e.g.,* Recommendation I.A.1, recommending a written and signed third-party "certification" of certain things. Although a distinction may exist between certification and verification, the provisions of the Final Rule requiring third-party verification of certain features use that term correctly and, together with the other provisions of the Final Rule, establish an adequate basis to reduce safety risks associated with BOP stacks. These rules provide a substantial upgrade over the previous rules that did not contain such provisions.

TABLE 3—REGULATORY IMPACT ANALYSIS COMMENTS AND RESPONSES

Topic	Comment	BSEE response
Regulatory Impact Analysis	The increased costs will negatively impact future OCS development. The IFR itself estimated the baseline risk of a catastrophic blowout at once every 26 years. 75 FR at 63365. This estimate for a blowout in the Gulf of Mexico is even lower, as it appears the estimate used by BOEMRE is based on worldwide catastrophic blowout data.	BSEE will continue to evaluate regulatory changes that could result in offsetting cost savings for OCS operators as directed by the President in his January 18, 2011 executive order, "Improving Regulation and Regulatory Review." The estimate for the risk of a catastrophic blowout event is based upon one recorded GOM catastrophic blowout event and the historical number of deepwater GOM wells drilled, not world-wide blowout data. Going forward, we estimated the drilling of 160 deepwater wells annually for cost estimation purposes. The 160 deepwater wells per year may be more than will be drilled when considering all of the factors influencing GOM deepwater activity outside of this specific regulation. At the time of this analysis (during the summer of 2010), this number was estimated to be a reasonable baseline for the regulatory benefit-cost analysis. If on average fewer than 160 deepwater wells are drilled annually, the baseline activity scenario provides an upper bound regulatory cost estimate. If an estimate of 120 deepwater wells per year is used in the benefit-cost calculation, both the cost and the benefit *i.e.,* interval between blowouts will decrease by approximately the same factor. The historical risk of a catastrophic blowout event will be reduced from once in 26 years to once in 34 years.

TABLE 3—REGULATORY IMPACT ANALYSIS COMMENTS AND RESPONSES—Continued

Topic	Comment	BSEE response
Regulatory Impact Analysis	The costs for compliance prepared by the Agency are not reflective of the total cost of compliance and thus will negatively affect both small and large businesses more than alleged by the Agency.	Multiple commenters suggested that the costs of this rulemaking were not fully captured in the Regulatory Impact Analysis. BSSE and BOEMRE used the best available information to determine the compliance cost estimates for this rulemaking. The commenters do not identify specific regulatory provision where costs are claimed to be underestimated. Several of the compliance costs commenters associated with this rulemaking reflect provisions in existing regulations. Additionally, no alternative cost estimates are provided by this commenter. External factors influencing the cost of operating on the OCS are not considered to be compliance costs of this rulemaking. As explained in other portions of this preamble, BSEE has both decreased and increased some cost estimates for provisions in this rulemaking. However, the net estimated compliance cost has decreased from the estimate contained in the IFR.
Regulatory Impact Analysis	The benefit-cost analysis implies that a blowout may pose more problems in deepwater where drilling a relief well is likely to take longer. I find this statement troubling. It could be considered to imply, that it takes longer to penetrate seawater than hard rock. As an example, two drilling targets are at 20,000 feet total vertical depth (TVD). One is in 500 feet of water and the other is in 5,000 feet of water. For a well drilled in 500 feet of water an additional 4,500 feet of hard rock drilling must be completed to reach the target. From public well data on the BOEMRE website, I found the following pair of wells:	API Number TVD Water Depth Time to Reach Total Depth 608124001700 28497 6959 ft 200 days 427084062600 28382 100 ft 390 days It is possible that the statement is true, that is due to a different distribution of TVD in shallow and deep water drilling targets. BOEMRE needs to be rigorous to see if its conjectures are supported by the data. This is part of a pattern of the claim that deep water activities are more risky than shallow water. This assumption is being made by BOEMRE as a result of the Deepwater Horizon incident The typical GOM exploratory well in shallow water takes less than 30 days to reach TVD. The typical GOM deepwater exploratory well takes nearly 90 days to reach TVD. This is primarily because, on average, shallow water wells are not drilled to depths as deep as deepwater wells. Well-completions for "wet" wells and abandonment for "dry" wells take additional time. While exceptions can be found, we maintain that in most cases our assumption will hold that a deepwater relief well will take longer than a shallow water relief well.
Regulatory Impact Analysis	The agency estimates 160 deepwater wells annually for the next 20 years. This is a very important estimate, since it drives the estimates of both the costs and benefits. Granted projections of the future in the oil and gas industry have been notoriously wrong. I see that 160 wells annually as overly optimistic. My reasons are: —Historical data show a declining trend of the most recent years with all observations below 160. —Deepwater Horizon incident will lead to less favorable conditions for drilling in the Gulf. —Natural Gas from shale is a major disruption coming to North American energy markets. This is analogous to the cellular phone technology replacing land line phones in the last 20 years. A better way of presenting the future benefits and costs is with a range of scenarios such as 160, 120 and 80 wells a year. The Deepwater Horizon incident will lead to less favorable conditions for drilling in the Gulf of Mexico.	A reduction in the number of wells drilled per year will reduce the estimated annual compliance costs as well as the corresponding likelihood of a catastrophic blowout and hence the potential gains from any improvements in reliability. How much the new regulatory environment will affect future OCS drilling is unknown at this time. BSEE estimates the drilling of 160 deepwater wells annually for cost estimation purposes. The 160 deepwater wells per year may be more than will be drilled when considering all of the factors influencing GOM deepwater activity outside of this specific regulation. At the time this analysis was prepared for the IFR during the summer of 2010, it was estimated to be a reasonable baseline for the regulatory benefit-cost analysis. One hundred sixty deepwater wells per year can serve as an upper bound cost estimate for the regulation. If an estimate of 120 deepwater wells per year is used in the benefit-cost calculation, both the cost and the benefit will decrease by approximately the same factor. The historical risk applied to future drilling estimates for 120 wells per year will reduce the estimated risk from once in 26 years to once in 34 years. For only 80 deepwater wells a year, the risk will be reduced to once each 52 years. A scenario analysis for 120 deepwater wells per year has been added to the benefit-cost analysis.
Regulatory Impact Analysis	BOEMRE estimates an equal likelihood of serious damage or sinking of a MODU drilling rig from a catastrophic blowout event. Press reports indicate the sinking of Deepwater Horizon was due to bad fire fighting procedures. That is, pouring seawater on the floating vessel causing it to sink. When the accident report is completed, new standard practices should emerge for fire fighting with the byproduct of great reduction in the probability of sinking.	BOEMRE's estimate, in the IFR, of an equal likelihood of loss or damage, is based on the two recorded events for severe damage or destruction of deepwater MODUs in the GOM. This rulemaking requires additional the testing of LMRP disconnect functionality. A disconnect of a deepwater MODU during a catastrophic event will likely protect the MODU from total loss. BSEE maintains that our baseline cost estimate for deepwater MODU damage is reasonable for purposes of this benefit cost analysis.

TABLE 3—REGULATORY IMPACT ANALYSIS COMMENTS AND RESPONSES—Continued

Topic	Comment	BSEE response
Regulatory Impact Analysis	The benefit-cost sensitivity analysis provided no basis for the assumption that reservoirs at depths of 3,000 feet are generally more prolific than their shallow water counterparts. That statement is contradicted by most recent Reserves Report (*http://www.gomr.boemre.gov/homepg/offshore/fldresv/2006-able4.pdf*) which shows of the 20 largest fields in the Gulf of Mexico, only five are located in depth greater than 3,000 feet.	The report referenced by the commenter does indicate that only 5 of the 20 largest GOM fields are in water depths greater than 3,000 feet. If the top 20 fields are further analyzed, 6 of the top 20 fields are in water depths of 2,860 feet or greater and discovered since 1989. Fourteen of the fields are in water depths 247 feet or less and discovered in 1971 or earlier. The GOM shelf is in decline and few large fields are likely to be discovered in the GOM shallow water. Over the last 40 years the largest fields with booked reserves have all been in deepwater. BSEE maintains that the basis for the sensitivity analysis that future discovered reservoirs at water depths of 3,000 feet or greater will be more prolific is a reasonable assumption for the benefit-cost scenario analysis for this rule.
Regulatory Impact Analysis	The agency's estimation of costs is not consistent with our own estimates and we strongly encourage the agency to carefully review the assumptions that went into your analysis. Moreover, to potentially assist you with your examination of the socio-economic costs and consequences of the regulation, we have enclosed a report we commissioned by IHS-Global Insight entitled, "The Economic Impact of the Gulf of Mexico Offshore Oil and Natural Gas Industry and the Role of the Independents," which determined that more than $106 billion in Federal, state, and local revenues would be lost over a 10-year period if independents were excluded from deepwater. Obviously, this report examined broader policy impacts than were encompassed in the particular regulation, but we believe it provides a useful data set to examine these regulations within a broader context of impacts.	We have reviewed the report by IHS-Global Insight and found nothing that will substantiate, contradict or otherwise provide compliance cost figures for this rulemaking. Since the commenter's own estimates were not provided, we cannot evaluate alternative cost estimates suggested by the commenter. The Final Rule does not exclude independents from deepwater drilling.
Regulatory Impact Analysis—Small Business Impacts.	In its notice, BOEMRE included certain information regarding the composition of the oil and gas industry and the small business entities—lessees, operators, and drilling contractors—that will be most affected by this interim rule. BOEMRE estimates that $29 million dollars or 15.8 percent of the IFR's total cost of $183 million will be borne by small businesses. This cost would comprise about 0.36 percent of these small businesses' fiscal year 2009 revenue. BOEMRE does not discuss how the regulation's costs would be distributed among small businesses. Advocacy is concerned that these costs will impact certain small businesses more heavily than others. We encourage BOEMRE to include additional information regarding how the industry functions and which small entities are most likely to incur increased costs as a result of this IFR. We also recommend that BOEMRE include a more detailed discussion of the distribution of costs among the small entities identified in the IRFA (Initial Regulatory Flexibility Analysis) in order to accurately determine whether some small entities will incur disproportionate impacts as a result of this rule. The RFA requires agencies to include in their IRFA a description of any significant alternatives to the proposed rule that minimize significant economic impacts on small entities while still accomplishing the agency's objectives. While BOEMRE did note a few alternatives in the interim rule, we recommend that BOEMRE include a more detailed discussion of the alternatives and their effects on small business and the reasons for or against adopting those alternatives. We further recommend that BOEMRE continue to conduct outreach with small entities affected by this rule and any future safety rules to develop alternatives that minimize disproportionate impacts on small entities.	BOEMRE published a separate IRFA on December 23, 2010 (75 FR 80717) with a 30 day comment period. The IRFA and the FRFA published with the final RIA provide the analysis required in the Regulatory Flexibility Act. This includes an estimate of the number of small entities affected, a description of reporting, recordkeeping requirements and evaluation of significant alternatives that could minimize the impacts on small entities while accomplishing the objectives of this rulemaking.

TABLE 3—REGULATORY IMPACT ANALYSIS COMMENTS AND RESPONSES—Continued

Topic	Comment	BSEE response
Regulatory Impact Analysis—Small Business Impacts.	A commenter estimated that the rulemaking will increase costs by $17.3 million for each deepwater well drilled with a MODU. This cost increase is attributed to required modification of the well plan and associated casing design that results in the addition of a liner and associated work.	The compliance costs for the IFR were estimated using the best available information at the time of publication. Neither the IFR nor this Final Rule requires operators to conform to a specific casing design, nor do they require new designs for well plans. The additional requirements of the IFR are intended to increase the safety of operating on the OCS considering the best available and safest technology. The commenter does not identify which elements increase either the time to drill a well by 15 rig days, or the cost by $17.3 million. Absent new and well-defined information, BSEE is unable to evaluate or adjust the compliance cost estimates for a deepwater well.
Regulatory Impact Analysis—Small Business Impacts § 250.449(h).	A commenter identified $10.45 million in BOP inspection cost savings per deepwater well. The proposal is to function test the blind-shear rams every 14 days instead of every 7 days as required by § 250.449(h). The commenter claims "prior to the Macondo incident, all the rams on the BOP were function tested once a week except for the blind-shear rams." Another commenter claims that " * * * frequent function testing of blind/shears will exacerbate this stack body wear and introduce further exposure to leakage within the BOP".	The Final Rule does not change the existing regulation at § 250.449(h) which requires a function test every 7 days including the blind-shear rams. The 7-day testing requirement existed before the Macondo event and is not being made more stringent with this rulemaking. The commenter's assertion that "prior to the Macondo incident, all the rams on the BOP were function tested once a week except for the blind-shear rams" is incorrect. The $10.45 million figure does not represent an additional compliance cost due to this rule, but an estimated cost savings to the company on a per-well basis if their recommendation for a once-every-two weeks function test requirement is accepted. A Joint Industry Project study completed in 2009 analyzed BOP equipment reliability. The results of this study suggest that up to $193 million per year could be saved through less frequent testing while achieving the same reliability for BOP performance. However, at this time BSEE believes increasing the duration between tests poses a greater risk than conducting the test on the current schedule. BOP testing frequency is a topic that merits further study.
Regulatory Impact Analysis—Small Business Impacts.	Several commenters claim that the compliance costs are significantly higher than BOEMRE's estimate. One comment suggests that the "Final Rule will add three to five times the amount the BOEMRE has published." Another comment claims that the new regulation will cost as much as $28 million per deepwater well for compliance, compared to the $1.42 million estimated by BOEMRE.	BSEE has considered the limited cost information provided by commenters and new time and cost estimates obtained by the bureau since the publication of the IFR. The commenter's $28 million compliance cost estimate includes a $10.45 million cost from additional BOP tests. However, these additional BOP tests do not represent additional costs, but a cost savings if the company's recommendation to function test the blind shear rams every 7 days instead of every 14 days (with regard to the previously existing regulation) is accepted. If the recommendation is not accepted, there is no increased compliance cost for this rulemaking. This proposal on function test intervals is outside the scope of this rulemaking as previously stated in the response to comments for § 250.449(h). The additional $17.3 million of compliance costs are claimed to result from "modified casing design" and "associated work." The lack of specific data or citations result in a vague and indeterminate interpretation of these cost estimates. BSEE does not specify well designs. If a new well design used by the operator is the result of industry best practices, it is not a compliance cost of the regulation. As such, BSEE cannot comment on the presumed cost impact for modified casing design and associated work.
IRFA	The IRFA published by BOEMRE does not satisfy the agency's statutory obligation under the Regulatory Flexibility Act of 1980, as amended. The commenter believes that, since there is not a good cause exception to the Administrative Procedure Act's notice and comment rulemaking requirement, BOEMRE was required to publish an IRFA at the time of the proposed rulemaking. Further, the IRFA BOEMRE eventually published did not account for the significant costs likely to be imposed by BOEMRE's new interpretation of 14,000 discretionary provisions found in API standards as mandatory permitting requirements.	The BSEE published an IRFA pursuant to the Regulatory Flexibility Act. While it was not published with the IFR, it was published shortly thereafter and made available for public comment. The SBA Office of Advocacy stated in its comments that "Advocacy appreciates BOEMRE's decision to publish a supplemental IRFA." The comments on the IRFA were considered along with all comments on the rulemaking.

TABLE 3—REGULATORY IMPACT ANALYSIS COMMENTS AND RESPONSES—Continued

Topic	Comment	BSEE response
		Regarding the 14,000 discretionary provisions from API standards, BSEE disagrees with the commenter's assertion that § 250.198(a)(3) will have resulted in significant additional costs. See the section-by-section discussion for further elaboration of this issue.

V. Section-by-Section Discussion of the Requirements in Final Rule

As of October 1, 2011, BOEMRE was officially reorganized into the separate agencies of BSEE and BOEM. This Final Rule reflects the appropriate name changes, based on the reorganization.

Nomenclature change. BSEE is revising all references to the term *glory hole* in the regulations at 30 CFR 250 to the term *well cellar.* This revision will amend text at two locations in the regulations (§§ 250.421(b) and 250.451(h)). Both terms refer to a depression deep enough to protect subsea equipment from ice-scour, when drilling in an ice-scour area. However, the term well cellar is more commonly used.

Service Fees (§ 250.125)

This Final Rule updates § 250.125(a)(8) and (9) in the chart to reflect accurate numbering redesignation.

Documents Incorporated by Reference (§ 250.198)

Final § 250.198(a)(3) has been modified from the IFR in response to many comments received on one important issue. Section 250.198(a)(3) pertains to how BSEE ensures compliance with documents incorporated by reference in its regulations. The provision in the IFR read as follows:

The effect of incorporation by reference of a document into the regulations in this part is that the incorporated document is a requirement. When a section in this part incorporates all of a document, you are responsible for complying with the provisions of that entire document, except to the extent that section provides otherwise. When a section in this part incorporates part of a document, you are responsible for complying with that part of the document as provided in that section. If any incorporated document uses the word *should,* it means *must* for purposes of these regulations. (75 FR 63372)

This provision was intended to clarify BSEE's existing policy on compliance with documents incorporated by reference in regulations. A number of commenters from the offshore oil and gas industry objected to this provision. The commenters were particularly concerned about the statement in the last sentence of the paragraph that for the documents incorporated by reference in 30 CFR part 250, the word ''*should*'' means ''*must.*'' Commenters asserted that there are 14,000 occurrences of the word ''*should*'' just in documents incorporated from the American Petroleum Institute (API). These commenters provided a number of examples in which they asserted that the last sentence of paragraph (a)(3) could cause conflicts; undermine safety, instead of improving safety on the Outer Continental Shelf (OCS); and, in certain circumstances, establish requirements with which compliance may be impossible. Accordingly, such commenters specifically requested that the agency remove the last sentence from paragraph (a)(3).

While some of the examples provided by commenters were overstated or did not account for alternatives or for the specifics in the operative language of the incorporated documents, we have removed the last sentence of paragraph (a)(3) as set forth in the IFR because it could have appeared to be overly broad and may not have provided the intended clarification.

The last sentence is not needed as a means of emphasizing the agency's interpretation of the binding effect of documents incorporated by reference, *i.e.,* BSEE relies on the specific regulatory provisions that incorporate a document by reference for the intended effects of each incorporation. The other portions of paragraph (a)(3) make it clear that operators are required to comply with documents incorporated by reference, unless the specific sections performing the incorporation provide otherwise. Moreover, many, but not all, of the individual sections of BSEE regulations that incorporate documents by reference are written in terms that make it clear that compliance is mandatory, even where the incorporated consensus standards were written as recommendations, not obligations.

This position is not a new one and was the agency's interpretation of documents incorporated by reference long before the adoption of the IFR. For instance, in a 1988 **Federal Register** preamble to the final rule converting agency orders into regulations, the MMS, a predecessor agency to BSEE and BOEM, responded to public comments on the effect of incorporating documents by reference in its rules as follows:

Comment—Objection was raised to the incorporation by reference of ''recommended practice'' documents which are intended only as *recommendations,* not as rules.

Response—When MMS adopts the specific provisions of a document through the rulemaking process, that incorporation by reference establishes the recommended practice as a minimum standard which must be observed.

Comment—A number of commenters expressed the view that with respect to documents incorporated by reference, it should be clear to what extent references within such incorporated documents are also binding. It was pointed out that documents proposed to be incorporated by reference in turn reference other documents, which reference other documents, down through numerous tiers.

Response—Under the final rule, the material that is incorporated by reference is specifically identified. Adherence to documents referenced within an incorporated document is mandatory if such adherence is necessary for compliance with the document referenced in the rule. (53 FR 10600)

We reaffirm our position stated in the agency's April 1, 1988, (53 FR 10600) rule that when BSEE adopts the specific provisions of a document through the rulemaking process, that incorporation by reference establishes the recommended practice as a minimum standard which must be observed.

We recognize, however, that certain regulations incorporating documents by reference either do not make compliance mandatory with the incorporated provisions, or provide operators some flexibility in achieving compliance. For instance, regulations at § 250.415(f) incorporate by reference API RP 65—Part 2, Isolating Potential Flow Zones During Well Construction. The requirement in § 250.415(f) specifies that operators must submit a written description of how they evaluated the best practices included in API RP 65—Part 2, not that they must comply with each of the best practices. This Final Rule is not intended to upset that interpretation or to modify the meaning of any particular regulatory provision that incorporates documents by reference.

To the extent that the commenters were correct in asserting that the last sentence of § 250.198(a)(3) in the IFR (or other regulations that establish mandatory compliance with incorporated documents) will lead to unintended consequences, BSEE's rules already provide the means for operators to seek relief in situations where they need an alternative means to comply. One provision, § 250.141, allows operators to use alternative procedures or equipment that provides a level of safety and environmental protection that equals or surpasses that required by BSEE rules. Another, § 250.142, provides for departures from operating requirements. Other provisions throughout BSEE regulations allow for departures related to specific circumstances (*e.g.,* plans, drilling operations, and structure removal). It should be noted that all of these departures require advance BSEE approval.

This approach was clarified in a March 28, 2011, Supplemental Information document that appears on the BSEE Web site. That document made it clear that the rules require operators to seek BOEMRE approval to deviate from a practice or procedure when the document incorporated by reference requires a particular practice or procedure.

Incorporation of API Standard 65—Part 2, Second Edition

In this Final Rule, we have modified § 250.198(h)(79) by incorporating the second edition of API Standard 65—Part 2 that was issued in December 2010. This change was made in response to comments. Previously, the first edition was incorporated. API also designated this recommended practice into a standard.

What must my casing and cementing programs include? (§ 250.415)

In the IFR, BOEMRE added a new § 250.415 (f) requiring the operator to include in its APD an evaluation of the best practices identified in API RP 65—Part 2, Isolating Potential Flow Zones During Well Construction. In the IFR, we also revised paragraphs (c), (d), and (e) to accommodate the new paragraph. The text of paragraph (f) was changed in this Final Rule to update the cross reference to sections 4 and 5 of the second edition of API Standard 65—Part 2. These sections correspond to sections 3 and 4 of the earlier edition that were previously cross-referenced. The basis and purpose for this section was set forth in the preamble of the IFR (75 FR 63346).

In response to comments, BSEE developed a table, set forth below, based on API Standard 65—Part 2 Annex D which outlines the process summary for isolating potential flow zones during well construction. For example, the operator may use Annex D or the following Table 4 as a guide for complying with the written description of how an operator evaluated the best practices included in API Standard 65—Part 2 required by § 250.415(f).

TABLE 4—EXAMPLE OF HOW TO EVALUATE THE BEST PRACTICES IN API STANDARD 65—PART 2

	GENERAL QUESTIONS	
1	Have you considered the following in your well planning and drilling plan determinations: evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well-control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, mud weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning? [API 65–2 1.5].	Yes/No.
2	Have you considered the general well practices while drilling, monitoring and maintaining wellbore stability, curing and preventing lost circulation, and planning and operational considerations? [API 65–2 1.6].	Yes/No.
	FLOW POTENTIAL	
3	Will a pre-spud hazard assessment be conducted for the proposed well site?	Yes/No.
4	List all potential flow zones within the well section to be cemented	Describe below.
5	Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or third parties)?	Yes/No.
	CRITICAL DRILLING FLUID PARAMETERS	
6	Are fluid densities sufficient to maintain well-control without inducing lost circulation?	Yes/No.
	CRITICAL WELL DESIGN PARAMETERS	
7	Will you use a cementing simulation model in the design of this well?	Yes/No.
7a	If yes, how is the output of this simulation model used in your decision-making process?	Describe below.
7b	If no, include discussion of why a model is not being used	Describe below.
7c	Either way, include the number and placement of centralizers being used	Describe below.
8	Will you ensure the planned top of cement will be 500 feet above the shallowest potential flow zone?	Yes/No.
9	Have you confirmed that the hole diameter is sufficient to provide adequate centralization?	Yes/No.
10	If there are any isolated annuli, how have you mitigated thermal casing pressure build-up?	NA or Describe below.
11	Will you ensure the well will be stable (no volume gain or losses, drilling fluid density equal in vs. out) before commencing cementing operations?	Yes/No.
12	List all annular mechanical barriers in your design	Describe below.
13	Has the rathole length been minimized or filled with drilling fluid with a density greater than the cement density?	Yes/No.
14a	If you have any liner top packers exposed to the production or intermediate annulus, what is the rating for differential pressure across this packer?	NA or Describe below.
14b	If you have any liner top packers exposed to the production or intermediate annulus, have you confirmed that your negative test will not exceed this rating?	Yes/No/NA.
15	What type of casing hanger lock-down mechanisms will be used?	Describe below.
16	For all intermediate and production casing hangers set in subsea, HP wellhead housing, will you immediately set/energize the lock-down *ring* prior to performing any negative test?	Yes/No.

TABLE 4—EXAMPLE OF HOW TO EVALUATE THE BEST PRACTICES IN API STANDARD 65—PART 2—Continued

17	For all production casing hangers set in subsea, HP wellhead housing, will you set/energize the lock-down *sleeve* immediately after running the casing and prior to performing any negative test?	Yes/No.
	CRITICAL OPERATIONAL PARAMETERS	
18	Will you have 1 mechanical barrier in addition to cement in your final casing string (or liner if it is your final string)?	Yes/No.
19	Do you plan to nipple down BOP in accordance with the WOC requirements in 30 CFR 250.422?	Yes/No.
20	Do you plan on running a cement bond log on the production and intermediate casing/liner prior to conducting the negative test on that string?	Yes/No.
	Are contingency plans in place for the following:	
21	Lost circulation?	Yes/No.
22	Unplanned shut-down?	Yes/No.
23	Unplanned rate change?	Yes/No.
24	Float equipment does not hold differential pressures?	Yes/No.
25	Surface Equipment issues?	Yes/No.
26	Will you monitor the annulus during cementing and WOC time?	Yes/No.
27	If using foam cement, is a risk assessment being conducted and incorporated into cementing plan?	Yes/No.
28	If using foam cement, will the foamer, stabilizer, and nitrogen injection be controlled by an automated process system?	Yes/No.
	CRITICAL MUD REMOVAL PARAMETERS	
28	Have you tested your drilling fluid and cementing fluid programs for compatibility to reduce possible contamination?	Yes/No.
29	Have you considered actual well conditions when determining appropriate cement volumes?	Yes/No.
30	Has the spacer been modeled or designed to achieve the best possible mud removal?	Yes/No.
	CRITICAL CEMENT SLURRY PARAMETERS	
31	Have all appropriate cement slurry parameters been considered to ensure the highest probability of isolating all potential flow zones?	Yes/No.
32	Do you plan on circulating bottom up prior to the start of the cement job?	Yes/No.

What must I include in the diverter and BOP descriptions? (§ 250.416)

The IFR revised § 250.416(d) to include the submission of a schematic drawing of all control systems, including primary control systems, secondary control systems, and pods for the BOP system. We did not revise this paragraph in the Final Rule.

The IFR revised § 250.416(e) to require the operator to submit independent third-party verification and supporting documentation that shows the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe in the hole under maximum anticipated surface pressure, as recommended in the Safety Measures Report. In response to comments received, we emphasize that the blind-shear rams must be capable of shearing heavy weight drill pipe. The Final Rule also revises § 250.416(e) to clarify that drill pipe includes workstring and tubing. The IFR provided that the supporting documentation has to include test results, but did not specify which tests are required. The Final Rule clarifies that the documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for MASP.

The IFR added § 250.416(f) to require independent third-party verification that a subsea BOP stack is designed for the specific equipment used on the rig. In the Final Rule, we revised this paragraph to also include surface BOP stacks on floating facilities to clarify the intent that this verification is required for all floating drilling operations. This section also includes the requirements for verification that the BOP stack has not been compromised or damaged from previous service. BSEE realizes that an APD may be submitted prior to the third-party verification. Under such circumstances, BSEE may issue a condition of approval in the APD contingent on the third-party verification. The verification must be completed prior to BOP latch-up onto the associated well. The third-party verification will be submitted to BSEE in an APD or a revised sidetrack permit.

The IFR added § 250.416(g) to describe the criteria and documentation for an independent third-party that must be submitted with the APD to BSEE for review.

In the IFR, § 250.416(g)(1) of this section referenced the independent party in § 250.416(e). This Final Rule removes this reference, since the requirements for the independent third-party in paragraph (g) apply to any use of the independent third-party in § 250.416.

We revised paragraph (g)(1) to specify that a registered professional engineer, or a technical classification society, or a licensed professional engineering firm, could qualify as the independent third-party under this section. We also removed the reference that the original equipment manufacturer (OEM) cannot be the independent third-party. We removed this prohibition so that the OEM, who has the expertise with the equipment, may function as the independent third-party under this section as long as it meets the requirements of the independent third-party outlined in this section.

Based on comments received, we have also revised qualifications for independent third parties to remove various standards that were not sufficiently objective or certain. We removed the provision from the IFR that the firm can be an API-licensed manufacturing, inspection, or certification firm, since API does not license such firms. We also removed the requirement that the firm must carry industry-standard levels of professional liability insurance, based on comments questioning how to determine ‘‘industry standard levels of professional liability insurance.’’ BSEE has not devised an approach to make this determination. We removed the requirement that the firm provide evidence that it is ''reputable'' because such a standard is too vague. Similarly, we removed the requirement that a firm have no record of violations of applicable law because it is not clear what ''applicable law'' refers to and how far back the requirement applies, and because state licensure or registration will assure current compliance. In place of the requirements that were removed, in response to comments discussed earlier, we added that evidence be provided to demonstrate that the person or entity performing the third-party verification has the expertise and experience necessary to perform the required verifications. Thus, the Final Rule requires evidence of appropriate licenses and evidence of expertise and experience to perform the verifications.

We also revised paragraph (g)(2)(ii) to change the notification of the appropriate BSEE District Manager from 24 hours in advance of any shearing ram tests or shearing ram inspections to 72 hours in advance. This amount of time will facilitate having a BSEE representative present to witness at least one of these tests. See the discussion of § 250.416 in the IFR (75 FR 63357 through 63358) for additional information on this section.

What additional information must I submit with my APD? (§ 250.418)

This Final Rule revises § 250.418(g) by adding the phrase ''below the mudline''. The revision is made to clarify the intent that the operator must submit a request for approval to wash out if the operator is washing out below the mudline, not for washing out the cement in all situations, as was previously provided.

The IFR added § 250.418(h), which requires operators to submit certifications of their casing and cementing program required by § 250.420(a)(6). Paragraph (h) is not revised in this Final Rule.

The IFR added § 250.418(i), requiring the operator to submit a description of qualifications of any independent third-party. Paragraph (i) is revised in this Final Rule by changing the cross reference in that paragraph to § 250.416(g), the paragraph that specifies the qualifications referred to instead of paragraph (f) as was provided in the IFR.

What well casing and cementing requirements must I meet? (§ 250.420)

The IFR added § 250.420(a)(6) that requires the operators to submit certification of their casing and cementing program signed by a Registered Professional Engineer. In the IFR, § 250.420(a)(6) also included certification requirements pertaining to two independent tested barriers. This Final Rule reorganizes § 250.420(a)(6) to focus solely on the required certification and the role of the persons making the certification. This Final Rule moves the requirements pertaining to two independent barriers to § 250.420(b)(3), discussed below.

The Registered Professional Engineer signing the certification must be registered in a State of the United States. In response to comments about the qualifications of the person performing the certification, this Final Rule specifies that the person signing the certification must have sufficient expertise and experience to perform the certification. During the review process, BSEE may disallow a certification if it concludes that the certifier's expertise and experience to perform the certification are inadequate. Although the regulation does not require that every certification be accompanied by documentation of the qualifications of the person performing the certification, BSEE may, on a case-by-case basis, request that such material be provided.

As was provided in the IFR, this Final Rule states that the Registered Professional Engineer reviewing the casing and cementing design must certify that the design is appropriate for the purpose for which it is intended, under expected wellbore conditions. We have also added that the certification must specify that the casing and cementing design is sufficient to satisfy the tests and requirements of §§ 250.420 and 250.423. In that manner, the certification ties into the substantive requirements of the regulations. Final § 250.420(a)(6) also provides that the Registered Professional Engineer must be involved in the casing and cementing design process. This requirement will assure that the Registered Professional Engineer will be familiar enough with the design process and the final design to make the required certification.

As mentioned above, this Final Rule moves the requirement pertaining to two independent barriers from § 250.420(a)(6) to final § 250.420(b)(3). In response to comments, this Final Rule revises this requirement to clarify the meaning of ''two independent tested barriers.'' We retained the requirement for two independent barriers, but removed the word ''tested,'' based on comments. The term ''two independent tested barriers'' was confusing. In response to comments inquiring as to which flow paths must have independent barriers, we clarify that on all wells that use subsea BOP stacks, the well must include two independent barriers, including one mechanical barrier, in each of the annular flow paths. We also added examples of acceptable types of barriers, including primary cement job and seal assembly.

In the IFR, § 250.420(b)(3) required the operator to install dual mechanical barriers in addition to cement for the final casing string (or liner if it is the final string), to prevent flow in the event of a failure in the cement. This Final Rule provides, instead, that for the final casing string (or liner if it is the final string), an operator must install one mechanical barrier in addition to cement, to prevent flow in the event of a failure in the cement. We have clarified that this requirement applies to the final casing string or liner, since that is the string of casing that will be exposed to wellbore conditions. Final § 250.420(b)(3) states that an operator must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE–0125) instead of 30 days after installation, as was provided in the IFR. This Final Rule also adds that these barriers cannot be modified prior to or during completion or abandonment operations.

The IFR stated that dual mechanical barriers may include dual float valves. In response to comments, we clarify that a dual float valve, by itself, is not considered a mechanical barrier.

We also added a provision that clarifies that the BSEE District Manager may approve alternative options. Although operators may apply for approval for use of alternative producers of equipment under existing BSEE regulations at § 250.141, we mention it specifically in this provision because we recognize that there are other approaches to prevent flow in the event of a failure in the cement.

What are the requirements for pressure testing casing? (§ 250.423)

The IFR reorganized § 250.423 to accommodate new requirements, redesignated the previous regulation as § 250.423(a) and added new § 250.423(b) and (c). Paragraph (b) was added to require the operator to perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner in the subsea wellhead or liner hanger. Paragraph (c) was added to require the operator to perform a negative pressure test on all wells to ensure proper installation of casing for the intermediate and production casing strings.

This Final Rule revises § 250.423(a) to clarify that if pressure declines more than 10 percent in a 30-minute test, or there is an indication of a leak, the operator must investigate the cause and receive approval from the appropriate BSEE District Manager for the repair (*e.g.,* re-cement, casing repair, or additional casing). BSEE revised the language to state that BSEE approval is needed.

This Final Rule, slightly rearranges § 250.423(b) for clarification to state, ''You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.'' This Final Rule also revises §§ 250.423(b)(1) from the IFR by separating the requirements for casing strings and liners into paragraphs (b)(1) and a new paragraph (b)(2), respectively.

New § 250.423(b)(2) provides that if the liner has a latching or lock down mechanism, the operator must ensure that the mechanism is engaged upon installation of the liner. This new provision clarifies that BSEE does not require the use of a latching or lock down mechanism, but if the mechanisms are used, they must be engaged upon installation.

The subsequent paragraphs, numbered as §§ 250.423(b)(2), (b)(3), and (b)(4) in the IFR, are renumbered as §§ 250.423(b)(3), (b)(3)(i), and (b)(3(ii)) in this Final Rule.

In response to comments, this Final Rule revises § 250.423(c) to require a negative pressure test be performed only on wells that use a subsea BOP stack or wells with a mudline suspension system instead of on all wells, as was provided in the IFR. Requiring the performance of negative pressure tests on wells that use a surface BOP stack is not necessary; it is more important to test the barriers in subsea wells and wells with a mudline suspension.

In response to comments, this Final Rule adds new §§ 250.423(c)(1) and (c)(2) to clarify when the negative pressure test must be performed. We specifically require the operator to perform a negative pressure test on the final casing string or liner. We also require a negative pressure test prior to unlatching the BOP. The negative pressure test is to be conducted on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected. The Final Rule provides that the BSEE District Manager may require performance of 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 in situations where it is appropriate. BSEE is requiring the negative pressure test on the final casing string or liner because the operator may decide to continue other operations on the well before the BOP is disconnected.

The subsequent paragraphs that were numbered §§ 250.423(c)(1) and (c)(2) in the IFR have been redesignated as §§ 250.423(c)(3) and (c)(4). The redesignated § 250.423(c)(3) is revised to clarify that if any of the test procedures or criteria for a successful test change, the operator must submit for approval the changes in an Revised APD or APM.

In response to comments, we added new paragraph (c)(5) to this section, which addresses what the operator must do in the event of an indication of a failed negative pressure test and includes examples of an indication of failure (pressure buildup or observed flow). The operator must investigate the cause of the possible failure, correct the problem, contact the appropriate BSEE District Manager, submit a description of the corrective action taken, and receive approval from the appropriate BSEE District Manager for the retest. Although a prudent operator would likely follow these steps in the absence of a regulatory provision, inclusion of paragraph (c)(5) is intended to provide assurance that these steps will occur, and also ensure that BSEE will be involved in these situations.

This Final Rule also adds § 250.423(c)(6), clarifying that operators must have two barriers in place prior to performing the negative pressure test. This safeguard is necessary to protect against well failure.

This Final Rule also adds § 250.423(c)(7), requiring documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE–0125).

What must I do in certain cementing and casing situations? (§ 250.428)

This Final Rule revises § 250.428(c) by removing § 250.428(c)(1) which allowed an operator to pressure test the casing shoe when the operator has an indication of an inadequate cement job. This section was removed because the pressure test of the casing shoe does not provide sufficient information to evaluate the integrity of the cement job. This change is consistent with other revisions in the IFR and this Final Rule and necessary to ensure the integrity of the cement job. This Final Rule revises § 250.428(c) to include ''gas cut mud'' as an indication of an inadequate cement job. The option to perform a cement ''bond'' log in paragraph (c)(3) is revised to allow operators to perform a cement ''evaluation'' log instead. This option was changed in the Final Rule to allow operators more flexibility to incorporate the use of newer technology to assess the cement job other than a bond log; however, an operator may still use a bond log as an evaluation tool. With previous § 250.428(c)(1) removed, the Final Rule renumbers the remaining paragraphs as § 250.428(c)(1), (c)(2), and (c)(3).

What are the requirements for a subsea BOP system? (§ 250.442)

Section 250.442 requires that when drilling with a subsea BOP system, the BOP system must be installed before drilling below the surface casing. The table in this section outlines specific BOP requirements.

Paragraph (a) was revised in the IFR to clarify that the blind-shear rams must be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures. In response to comments, this Final Rule revises § 250.442(a) to clarify that drill pipe includes workstring and tubing.

The IFR redesignated the requirement in previous § 250.442(d) to have an operable dual-pod control system as new § 250.442(b), without substantive change. This Final Rule does not modify the redesignated paragraph.

The IFR added § 250.442(d), containing requirements related to ROV intervention capability. This Final rule does not modify these requirements.

The IFR added § 250.442(e), requiring operators to maintain an ROV and have a trained ROV crew on each floating drilling rig on a continuous basis. This Final Rule modifies § 250.442(e) by removing the word ''floating'', which conflicted with the table heading ''when drilling with a subsea BOP system'' and created confusion as to the agency's intent. This Final Rule clarifies that when drilling with a subsea BOP system, the operator must maintain an ROV and have a trained ROV crew on each drilling rig (floating or not) on a continuous basis once BOP deployment has been initiated from the rig (the stack has been splashed) until the BOP is recovered to the surface.

The IFR added § 250.442(f), containing requirements related to autoshear and deadman systems. This Final Rule revises §§ 250.442(f)(1) and (2) in the IFR to specify that the autoshear system and deadman system must each be able to close, at a minimum, one set of blind-shear rams, instead of one set of shear rams. We revised the language to ensure that the shearing rams, when activated, will be capable of sealing the wellbore. We also revised § 250.442(f)(3) to clarify that the acoustic system will be a secondary control system, and cannot supplant a required control system. This Final Rule provides that if an operator intends to install an acoustic control system, it must demonstrate to BSEE, as part of the information submitted under § 250.416, that the acoustic system will function in the anticipated environment and conditions.

The following paragraphs were added in the IFR: § 250.442(g), requiring the operator to have operational or physical barrier(s) on BOP control panels to prevent accidental use of disconnect functions; § 250.442(h), requiring the operator to clearly label all control panels for the subsea BOP system; § 250.442(i), requiring the operator to develop and use a management system for operating the BOP system (the operator may include this with its SEMS program as described in 30 CFR 250 subpart S); and § 250.442(j), requiring the operator to establish minimum requirements for personnel authorized to operate critical BOP equipment. This Final Rule does not revise these paragraphs.

This Final Rule removes § 250.442(l), addressing the use of BOP systems in ice-scour areas. This paragraph duplicated § 250.451(h), and does not need to appear in two places in the CFR.

What associated systems and related equipment must all BOP systems include? (§ 250.443)

This Final rule revises § 250.443(g) to clarify that all BOP systems must include a wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure instead of the maximum anticipated surface pressure as was previously provided. This revision clarifies what is required when using subsea systems and is made to be as consistent as possible with a recommendation in the DWH JIT report.

What are the BOP maintenance and inspection requirements? (§ 250.446)

The IFR revised § 250.446(a) to require the operator to document the procedures used and to record the results of BOP system maintenance and inspection actions, and make the records available to BSEE upon request. This Final Rule further revises § 250.446(a) to clarify that the documentation requirements pertain to how the BOP system maintenance and inspections met or exceeded the specific API RP 53 provisions referenced earlier in that section.

The IFR specified that the documents required in § 250.446(a) must be maintained on the rig for two years or from the date of the last major inspection, whichever is longer. The rule did not state how long from the date of the last major inspection the records must be kept. To clarify and simplify the timeframe for keeping records, the Final Rule provides that records must be maintained on the rig for two years from the date the records are created or for longer if directed by BSEE.

The requirement for the BOP system maintenance and inspection records to be maintained on the rig for a minimum of two years will assure that the records will be kept at the location of, and follow, the BOP system if and when the rig changes locations. This requirement will help ensure that persons responsible for using a BOP system in the future will be able to identify any earlier problems with the BOP system and will be able to take necessary steps to try to prevent recurrence of such problems.

As with other activities they perform, drilling contractors who control the drilling rig and perform BOP system maintenance and inspections are responsible for the documentation and recordkeeping requirements of § 250.446(a), see § 250.146(c). Failure to satisfy these obligations will subject all responsible persons, including contractors, to BSEE enforcement.

Once the two year obligation for maintaining records begins, a contractor controlling the rig will continue to have the record-keeping responsibility even if the rig subsequently moves and is used for drilling on different leases with different operators. To satisfy their obligations, the original lessee and operator will need to obtain assurance from a contractor in possession of the BOP system maintenance and inspection records for the wells on its lease that the records will be kept and made available to BSEE for the required period.

What additional BOP testing requirements must I meet? (§ 250.449)

In conjunction with the changes from the IFR regarding stump test requirements, this Final Rule revises § 250.449(b) to clarify that the time lapse between the stump test of a subsea BOP system and the initial test of a subsea BOP system on the seafloor must not exceed 30 days. This practice is already common in industry and BSEE policy. The IFR added § 250.449(j) requiring certain testing during the stump test and during the initial testing on the seafloor, but did not specify the temporal relationship between the two sets of tests. This Final Rule clarifies the timing.

This revision is intended to help ensure that the condition of a BOP has not deteriorated between the stump test and the actual use of the BOP. The previous rules did not have a timeframe between the BOP system stump test and the initial BOP system test on the seafloor. In response to operator inquiries, BSEE's Gulf of Mexico region established a policy that BOP system stump tests are to be performed within 30 days of the initial BOP system test on the seafloor, to preclude reliance upon stump tests that do not accurately reflect the condition of the BOP system at the time of installation. This Final Rule codifies that policy, and will ensure that operators will not rely upon older stump tests to satisfy § 250.449(b). This provision is not expected to impact operations to any great degree because stump tests of subsea BOP systems typically occur shortly before BOP systems are initially installed.

The IFR made slight editorial changes to §§ 250.449(h) and (i) to account for the new paragraphs following those sections. This Final Rule makes no further changes to §§ 250.449(h) and (i).

The IFR added §§ 250.449(j) and (k). In response to comments that the BOP tests are insufficient, we revised § 250.449(j) to require the operator to test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab and to clarify that each ROV must be fully compatible with the BOP stack intervention panels. The Final Rule also clarifies that when an operator submits the test procedures to BSEE for approval, the operator must include how it will test each ROV intervention function.

This Final Rule also adds a new paragraph, § 250.449(j)(2), which requires a 72-hour notification prior to the initiation of a stump test and initial test on the seafloor. Operators must notify BSEE at least 72 hours prior to all BOP stump tests and initial BOP tests on the seafloor to facilitate having a BSEE representative present to witness at least one of these tests. The subsequent paragraph, § 250.449(j)(2) in the IFR, has been redesignated as § 250.449(j)(3) in this Final Rule.

In response to comments, this Final Rule revises § 250.449(k) to require the operator to test the deadman system and verify closure of a set of blind-shear rams during the initial test on the seafloor. The Final rule also adds new clarification to ensure that the well is secure and that hydrocarbon flow would be isolated during the initial deadman test on the seafloor. For example if hydrocarbons are present in the well, the hydrocarbon flow could be isolated by closing appropriate production safety devices, required in subpart H of this part, installing plugs, and/or cementing. Also to help mitigate risk for the function test of the deadman system during the initial test on the seafloor, we added a provision that there must be an ROV on bottom. The ROV is located on bottom to assist in the testing, as needed, and as a back-up to disconnect the LMRP should the rig experience a loss of station event.

In response to comments BSEE also revised final § 250.449(k)(1) to clarify that the required submittals of procedures for the autoshear and deadman function testing must include documentation of the controls and circuitry of the system utilized during each test. This documentation is necessary to verify that the same deadman controls are used in testing and emergency activation. This Final Rule also specifies that the submittals include procedures on how the ROV will be utilized during testing.

For the same reasons, BSEE made corresponding changes in final §§ 250.517(d)(9), 250.617(h)(2), and 250.1707(h)(2).

What must I do in certain situations involving BOP equipment or systems? (§ 250.451)

As described above, this Final Rule revises § 250.451(h), to replace the term ''glory hole'' with the term ''well cellar.'' This Final Rule also adds new § 250.451(j) stating that before an operator removes the BOP it must have two barriers in place, and that the BSEE District Manager may require additional barriers. This provision was added to provide clarification for barrier requirements prior to removing the BOP stack, and is a safeguard necessary to protect against well failure. This regulation is intended to apply to normal, planned operations; however, if the operator encounters an unexpected situation as outlined in § 250.402, the operator should still follow those guidelines as appropriate.

What safe practices must the drilling fluid program follow? (§ 250.456)

The IFR redesignated then existing § 250.456(j) as § 250.456(k) and added a new § 250.456(j) to require approval from the BSEE District Manager before displacing kill-weight fluid from the wellbore.

This Final Rule revises § 250.456(j) to clarify that the operator must receive prior approval before displacing kill-weight fluid from the wellbore and/or riser to an underbalanced state. The IFR required prior approval whenever kill-weight fluid would be displaced from the wellbore, even if the wellbore would not be underbalanced. It is not necessary to receive approval if the wellbore will remain in an overbalanced state.

This Final Rule also revises § 250.456(j)(1) to conform the flow path description to that contained in § 250.420(b)(3), and § 250.456(j)(4) to clarify that the monitoring procedures are required for monitoring the volumes and rates of fluids entering and leaving the wellbore.

Approval and Reporting of Well-Completion Operations (§ 250.513)

In this Final Rule, we added a new § 250.513(b)(4) as a conforming procedural amendment requiring the operator to submit with the APD or APM the BOP descriptions for well-completion operations required in the new § 250.515. This new paragraph does not require information in addition to that already required, but will ensure information required under the new § 250.515 is submitted with the APD or APM. To accommodate the new paragraph (b)(4), this Final Rule redesignates previous §§ 250.513(b)(4) and (b)(5) as §§ 250.513(b)(5) and (b)(6).

Well-Control Fluids, Equipment, and Operations (§ 250.514)

In response to comments that requirements for well-completion and drilling should be consistent, this Final Rule adds § 250.514(d). This new paragraph makes the requirements for well-control fluids for well-completions consistent with the requirements for drilling (§ 250.456(j)). As with the drilling requirements, before displacing kill-weight fluid from the wellbore and/or riser to an underbalanced state, the operator must obtain approval from the appropriate BSEE District Manager. To obtain this approval, the operator must submit with the APD or APM the reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how this will be done. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers that are in place for each flow path that requires such barriers,

(2) Tests the operator will conduct to ensure integrity of independent barriers,

(3) BOP procedures the operator will use while displacing kill-weight fluids, and

(4) Procedures the operator will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

What BOP information must I submit? (§ 250.515)

In response to comments, this Final Rule adds a new § 250.515 which conforms well-completion BOP information requirements to those of the drilling and workover subparts, where the same type of equipment may be used, and similar safety risks exist. To accommodate the new section, this Final Rule redesignates §§ 250.515 through 250.530 as §§ 250.516 through 250.531.

New § 250.515 requires operators to include BOP descriptions in the APM for well-completion operations. The operator must include a description of the BOP system and system components and a schematic drawing of the BOP system. The operator must also include independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual test results and calculations of shearing capacity of all pipe that will be used in the well including correction for MASP. The operator must also include, when using a subsea BOP stack, independent third-party verification that shows: 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.

Final § 250.515(e) requires operators to include the qualifications of the independent third-party performing the verifications. The independent third-party must be a registered professional engineer, or from a technical classification society, or a licensed professional engineering firm capable of providing the verifications required under this part. In the qualifications, the operator must include evidence that the registered professional engineer, or a technical classification society, or engineering firm the operator is using to perform the verification or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications. The operator must ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, the operator must notify the BSEE District Manager at least 72 hours in advance. This new section makes the requirements for submission of BOP information for well-completions consistent with the requirements in subpart D (§§ 250.416(c) through (g)).

Blowout Prevention Equipment (§ 250.515 in the Interim Final Rule, Redesignated as § 250.516 in This Final Rule)

The IFR added the requirements of § 250.442 in subpart D, Oil and Gas Drilling Operations, to the requirements in § 250.515 for well-completion operations using a subsea BOP stack. This Final Rule redesignates § 250.515 in the IFR as § 250.516, but makes no further changes to that section.

Blowout Preventer System Tests, Inspections, and Maintenance (§ 250.516 in the Interim Final Rule, Redesignated as § 250.517 in This Final Rule)

The IFR added § 250.516(d)(8) to require tests for ROV intervention functions during the stump test and § 250.516(d)(9) to require a function test of the autoshear and deadman system. This Final Rule redesignates § 250.516 as § 250.517.

This Final Rule revises redesignated § 250.517(d)(2) to specify that the time lapse between the stump test of a subsea BOP system and initial BOP system test on the seafloor must not exceed 30 days; see the discussion of § 250.449(b) earlier in this preamble concerning inclusion of the same timeframe in subpart D.

This Final Rule revises redesignated § 250.517(d)(8) to require the operator to test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab, and that each ROV must be fully compatible with the BOP stack intervention panels. This Final Rule also adds a requirement that when an operator submits the test procedures, it must include how it will test each ROV function. This Final Rule adds a 72-hour notification requirement in § 250.517(d)(8)(ii). Operators are required to notify BSEE at least 72 hours prior to all BOP stump tests and initial BOP tests on the seafloor to facilitate having a BSEE representative present to witness at least one of these tests. Changes to redesignated § 250.517(d)(8) are consistent with changes to final § 250.449(j) as discussed earlier.

This Final Rule revises redesignated § 250.517(d)(9) to require the operator to test the deadman system and verify closure of a set of blind-shear rams during the initial test on the seafloor. The verification requirement is new and is consistent with revised § 250.449(k).

The IFR revised previous §§ 250.516(g) and (h) to expand and clarify the requirements for BOP inspections and maintenance. This Final Rule revises redesignated §§ 250.517(g) and (h) to clarify the documentation requirements include showing how an operator met or exceeded specific API RP 53 sections. This Final Rule also revises redesignated §§ 250.517(g) and (h) to clarify the recordkeeping timeframe to require that an operator must maintain records on the rig for two years from the date of creation or for longer if directed by BSEE.

This Final Rule revises redesignated § 250.517(g)(2) to be consistent with the subsea BOP system and marine riser inspection requirements in subpart D, § 250.446(b). It requires the visual inspection of surface BOP systems on a daily basis. It requires the visual inspection of subsea BOP systems and marine risers at least once every three days, instead of every day as was provided in the IFR. This revision reduces the number of required inspections of subsea BOP systems and marine risers.

Approval and Reporting of Well-Workover Operations (§ 250.613)

This Final Rule adds a new § 250.613(b)(3) that requires an operator to submit, with its APM, the information required in the new § 250.615. This new paragraph was added to ensure that BOP descriptions for well-workover operations, required under the new § 250.615, will be submitted with the APM. To accommodate the new § 250.613(b)(3), this Final Rule redesignates §§ 250.613(b)(3) and (b)(4) as §§ 250.613(b)(4) and (b)(5).

Well-Control Fluids, Equipment, and Operations (§ 250.614)

In response to comments, this Final Rule adds a new § 250.614(d). This new paragraph makes the requirements for well-control fluids for well-workover operations consistent with the requirements in subpart D (§ 250.456(j)). As with the drilling requirements, before displacing kill-weight fluid from the wellbore to an underbalanced state, the operator must obtain approval from the appropriate BSEE District Manager. To obtain this approval, the operator must submit, with the APM, the reasons for displacing the kill-weight fluid, and provide detailed step-by-step written procedures describing how this will be accomplished. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers that are in place for each flow path,

(2) Tests the operator will conduct to ensure integrity of independent barriers,

(3) BOP procedures the operator will use while displacing kill-weight fluids, and

(4) Procedures the operator will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

What BOP information must I submit? (§ 250.615)

In response to comments, this Final Rule adds a new section, § 250.615. This new section makes the requirements for submission of BOP information for well-completions consistent with the requirements in subpart D (§§ 250.416(c) through (g)). This section requires operators to include BOP descriptions in the APM for well-completion operations. The operator must include a description of the BOP system and system components, and a schematic drawing of the BOP system. The operator must also include independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual test results and calculations of shearing capacity of all pipes to be used in the well, including correcting for MASP. Operators must also include, when using a subsea BOP stack, independent third-party verification that shows: 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 properly in the conditions in which it will be used.

The operators must include qualifications of the independent third-party. The independent third-party in this section must be a registered professional engineer, or a technical classification society, or a licensed professional engineering firm capable of providing the verifications required under this part. In the qualifications, the operator must include evidence that the registered professional engineer, or a technical classification society, or engineering firm the operator is using to perform the verification or its employees holds appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications. The operator must ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, the operator must notify the BSEE District Manager at least 72 hours in advance to facilitate having a BSEE representative present to witness at least one of these tests.

To accommodate the new section, this Final Rule redesignates previous §§ 250.615 through 250.619 as §§ 250.616 through 250.620.

Blowout Prevention Equipment (§ 250.615 in the Interim Final Rule, Redesignated as § 250.616 in Final Rule)

The IFR added new §§ 250.615(b)(5) and (e) that applied the requirements of § 250.442 in subpart D, Oil and Gas Drilling Operations, to well-workover operations using a subsea BOP stack. This Final Rule redesignates this section as § 250.616, but does not substantively change the IFR.

Blowout Preventer System Testing, Records, and Drills (§ 250.616 in the Interim Final Rule IFR, Redesignated as § 250.617 in This Final Rule)

The IFR added § 250.616(h) to require an operator to stump test a subsea BOP system before installation. It added § 250.616(h)(1) to require tests for ROV intervention functions during the stump test, § 250.616(h)(2) to require a function test of the autoshear and deadman system, and § 250.616(h)(3) to require the use of water to stump test a subsea BOP system. This Final Rule redesignates this section as § 250.617.

This Final Rule revises redesignated § 250.617(h) to be consistent with final §§ 250.449 and 250.517. It requires that the initial test on the seafloor must be conducted within 30 days of the stump test of the subsea BOP stack. This subsection does not add a new requirement; it just specifies the timing of the test. This Final Rule revises redesignated § 250.617(h)(1) to require the operator to test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab and that each ROV must be fully compatible with the BOP stack intervention panels. It also adds that when an operator submits the test procedures it must include how it will test each ROV function.

The Final Rule also adds § 250.617(h)(1)(ii) which includes a notification provision requiring operators to notify BSEE at least 72 hours prior to all BOP stump tests and initial BOP tests on the seafloor to facilitate having a BSEE representative present to witness at least one of these tests. This Final Rule revises redesignated § 250.617(h)(2) to require the operator to test the deadman system and verify closure of a set of blind-shear rams during the initial test on the seafloor. This Final Rule moves the contents of redesignated § 250.617(h)(2)(iii) into the general text of § 250.617(h).

What are my BOP inspection and maintenance requirements? (§ 250.617 in the Interim Final Rule, § 250.618 in the Final Rule)

The IFR added § 250.617 to apply the requirements of § 250.446 in subpart D, Oil and Gas Drilling Operations, to the inspections and maintenance requirements for well-workover operations using a subsea BOP stack. This Final Rule redesignates § 250.617 as § 250.618. This Final Rule revises redesignated § 250.618(a) to clarify that the documentation requirements include showing how an operator met or exceeded specific API RP 53 sections. It also clarifies the recordkeeping timeframe to require records to be maintained on the rig for 2 years from the date the records are created or for longer if directed by BSEE. The previous text was confusing.

This Final Rule also revises redesignated §§ 250.618(a)(2) be consistent with the subsea BOP system and marine riser inspection requirements in subpart D, § 250.446(b). It requires the visual inspection of surface BOP systems on a daily basis. It requires the visual inspection of subsea BOP systems and marine risers at least once every 3 days, instead of every day. This revision reduces the number of required inspections of the subsea BOP system and marine riser.

Definitions (§ 250.1500)

In the IFR, BOEMRE added separate definitions for the terms *deepwater well-control, well servicing and well-completion/well-workover.* This Final Rule makes no further changes to those definitions.

We have clarified the definition of *well-control* to be as consistent as possible with recommendations in the DWH JIT report. In the Final Rule we also clarify that *well-control* applies to abandonment operations. The Final Rule provides that *well-control* means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. *Well-control* applies to drilling, well-completion, well-workover, abandonment, and well-servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment.

Inclusion of this revised definition in subpart O will facilitate the establishment of minimum training standards for persons monitoring and maintaining well-control. This new definition encompasses anyone who has the responsibility for monitoring the well and/or maintaining the well-control equipment for well control purposes.

What are my general responsibilities for training? (§ 250.1503)

In the IFR, the operator is required to ensure that employees and contract personnel are trained in deepwater well-control when conducting operations with a subsea BOP stack. They must have a comprehensive knowledge of deepwater well-control equipment, practices, and theory. We did not make any changes to this section in the Final Rule.

When must I submit decommissioning applications and reports? (§ 250.1704)

This Final Rule revises § 250.1704(g) by adding § 250.1704(g)(1)(ii) to provide clarification that when an operator uses a BOP for abandonment operations, it must include the information required under § 250.1705, discussed below.

What BOP information must I submit? (§ 250.1705)

In response to comment, this Final Rule adds § 250.1705. BSEE received a comment stating that some BOP requirements were omitted in subparts E and F that should be included to ensure consistency of BOP requirements with subpart D. We agree with this comment and have made the appropriate changes in those subparts. This reasoning has also led us to conclude these requirements should also be extended to subpart Q. The same BOP equipment may be used in abandonment operations as is used in operations under the other subparts. Attendant safety risks are also similar and justify imposition of the same regulatory oversight in subpart Q as that contained in the other subparts.

Final Rule § 250.1705 requires operators to include BOP descriptions in the APM for well-completion operations. The operator must include a description of the BOP system and system components and a schematic drawing of the BOP system. The operator must also include independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include test results and calculations of shearing capacity of all pipe to be used in the well, including correction for MASP. The operator must also include, when using a subsea BOP stack, independent third-party verification that shows: 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.

The operators must include qualifications of the independent third-party. The independent third-party in this section must be a registered professional engineer, or technical classification society, or a licensed professional engineering firm capable of providing the verifications required under this part. In the qualifications, the operator must include evidence that the registered professional engineer, or a technical classification society, or engineering firm it is using to perform the verifications or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications. The operator must ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, the operator must notify the BSEE District Manager at least 72 hours in advance. This new section makes the requirements for submission of BOP information for well-completions consistent with the requirements in subpart D (§ 250.416(c) through (g)).

What are the requirements for blowout prevention equipment? (§ 250.1706)

BSEE received a comment stating that BOP requirements were omitted in subparts E and F. We agree with this comment; it is important for BOP requirements to be consistent, regardless of the application. We have made the appropriate changes in those subparts and also have included these requirements in subpart Q for abandonment operations that use a BOP system. In response to the comment, this Final Rule adds § 250.1706, which also adds consistency for BOP requirements between subparts. If the operator plans to use a BOP for any well abandonment operations, the BOP must meet the same requirements as those in subpart F, § 250.616.

What are the requirements for blowout preventer system testing, records, and drills? (§ 250.1707)

BSEE received a comment stating that BOP requirements were omitted in subparts E and F. We agree with this comment; it is important for BOP requirements to be consistent, regardless of the application. We have made the appropriate changes in those subparts and also have included these requirements in subpart Q for abandonment operations that use a BOP system. Since the new sections are added for BOP requirements in subpart Q, this Final Rule also adds § 250.1707 to ensure operators meet the same testing and recordkeeping requirements as those in subparts D, E, and F.

What are my BOP inspection and maintenance requirements? (§ 250.1708)

BSEE received a comment stating that BOP requirements were omitted in subparts E and F. We agree with this comment; it is important for BOP requirements to be consistent, regardless of the application. We have made the appropriate changes in those subparts and also have included these requirements in subpart Q for abandonment operations that use a BOP system. Since the new sections are added for BOP requirements in subpart Q, this new section is added to the Final Rule to ensure operators maintain and inspect the BOP equipment as required in subparts D, E, and F.

What are my well-control fluid requirements? (§ 250.1709)

In response to comments, we added a new section in the Final Rule. This new section makes the requirements for well-control fluids for well abandonment consistent with the requirements for drilling (§ 250.456(j)). As with the drilling requirements, before displacing kill-weight fluid from the wellbore to an underbalanced state, the operator must obtain approval from the appropriate BSEE District Manager. To obtain this approval, the operator must submit with the APM the reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how the displacement will be accomplished. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers that are in place for each flow path,

(2) Tests you will conduct to ensure integrity of independent barriers,

(3) BOP procedures you will use while displacing kill-weight fluids, and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

What information must I submit before I permanently plug a well or zone? (§ 250.1712)

In the IFR, a new paragraph (g) was added and paragraphs (e) and (f)(14) were revised to accommodate the new paragraph. New paragraph (g) requires operators to submit certification by a Registered Professional Engineer of the well abandonment design and procedures. The Registered Professional Engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification. The Registered Professional Engineer does not have to be licensed for a specific discipline, but must be capable of reviewing and certifying that the casing design is appropriate for the purpose for which it is intended under expected wellbore conditions. The IFR provided that the Registered Professional Engineer certifies that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during well abandonment activities. The IFR also provided that the Registered Professional Engineer certify that the plug meets the requirements in the table in § 250.1715.

In response to comments, the language in the Final Rule paragraph (g) was clarified that the Registered Professional Engineer must certify the well abandonment design and that all applicable plugs meet the requirements in the table in § 250.1715. In response to comments related to § 250.420(b)(3) discussed earlier, the Registered Professional Engineer must also certify that the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore, as described in § 250.420(b)(3).

How must I permanently plug a well? (§ 250.1715)

The Final Rule adopts a conforming change to § 250.1715 by adding paragraph (a)(11) which ensures that two independent barriers, as described in § 250.420(b)(3), will be put in place for abandonment if the barriers have been removed for production. Both the IFR and this Final Rule already require certification of the design of such barriers in § 250.1712(g), and the amendment to § 250.1715 is necessary to accompany the certification.

If I temporarily abandon a well that I plan to re-enter, what must I do? (§ 250.1721)

In the IFR, new paragraph (h) was added to require operators to submit certification by a Registered Professional Engineer of the well abandonment design and procedures.

In response to comments, language in paragraph (h) in the Final Rule was clarified that the Registered Professional Engineer must certify the well abandonment design and procedures. The Registered Professional Engineer must also certify that the design includes two independent barriers in the center wellbore and all annuli, one of which must be a mechanical barrier. The text has been modified from the IFR to be consistent with the requirements of § 250.420(b)(3).

VI. Compliance Costs

The IFR contained a table estimating compliance costs on a section-by-section basis. Since the IFR was published, we have reanalyzed compliance costs based on actual experience under the rule. In addition, this Final Rule modifies various provisions of the IFR. The following table provides a summary comparison between the compliance costs of the IFR and this Final Rule. The following table demonstrates that the estimated compliance costs have decreased by approximately 52 million dollars.

ESTIMATED COMPLIANCE COSTS COMPARISON BETWEEN THE INTERIM FINAL RULE AND THE FINAL RULE

Annual recurring costs	IFR ($ millions)	Final Rule ($ millions)	Compliance cost change between IFR and Final Rule
Subsea ROV function testing (drilling)	102.7	17.1	Estimated time was reduced. BSEE over estimated the time required for the subsea tests.
Subsea ROV function testing (completions/workover/abandonments).	15.5	5.5	Estimated time was reduced. BSEE over estimated the time required for the subsea tests. Count of abandonment operations added to revised count of workover/completions.
Test casing strings for proper installation (negative pressure test).	45.1	12.8	Regulation was changed and the count of actions is reduced. BSEE no longer requires a negative pressure test on all intermediate casing strings, only the final casing before the subsea BOP is removed.
Installation of two independent barriers, one of which must be a mechanical barrier.	10.3	83.0	Regulation was changed from dual mechanical barriers. A dual float valve no longer meets the definition of a mechanical barrier. The estimated time to install the mechanical barrier increased to 12 hours.
PE certification for well design	6.0	3.9	Cost estimate reduced because the large companies drilling in shallow water are now assumed to have Professional PE available for in-house certification.
Emergency cost of activated shear rams or LMRP disconnect.	2.6	2.6	No change.
Independent third-party shear certification	1.2	1.2	No change.
Paperwork Costs taken from PRA tables in IFR & Final Rule.	0.0	4.6	Paperwork costs were not included in the IFR benefit-cost analysis, but are added to the compliance cost for the final rule.
Total	183.4	130.7	

VII. Procedural Matters

Regulatory Planning and Review (Executive Orders 12866 and 13563)

This rulemaking constitutes a significant rule as determined by the Office of Management and Budget (OMB) and is subject to review under E.O. 12866. For purposes of this analysis, we deem the rulemaking to consist of the IFR as modified by this Final Rule.

(1) This rulemaking will have an annual effect of $100 million or more on the economy. The following discussion summarizes a Regulatory Impact Analysis (RIA) that is available on *www.Regulations.gov.* Use the keyword/ID ''BSEE–2012–0002'' to locate the docket for this rule.

BSEE estimates the annual cost of this rulemaking to be approximately $131 million per year. Because of regulatory changes in this Final Rule and revised cost assumptions, the annual compliance cost is reduced from $183 million estimated in the IFR to $131 million for the final regulatory impact analysis. The quantification of benefits is uncertain, but is estimated to be represented by the avoided costs of a catastrophic spill, which are estimated under the stipulated scenario as being $16.3 billion per spill avoided and annualized at $631 million per year.

Based on the occurrence of only a single catastrophic blowout, the number of GOM deepwater wells drilled historically (4,123), and the forecasted future drilling activity in the GOM (160 deepwater wells per year), we estimate the baseline risk of a catastrophic blowout to be about once every 26 years. Combining the baseline likelihood of occurrence with the cost of a representative spill implies that the expected annualized damage cost absent this regulation is $631 million ($16.3 billion once in 26 years, equally likely in any 1 year). To balance the $131 million annual cost imposed by this rulemaking with the expected benefits, the reliability of the well-control system needs to improve by 21 percent ($131 million/$631 million). We have found no studies that evaluate the degree of actual improvement that could be expected from dual barriers, negative pressure tests, and a seafloor ROV function test and no additional information was provided during the public comment period. However, based upon the plausible scenarios that have been developed, it is reasonable to conclude that this rulemaking will reduce the risk of a catastrophic blowout spill event such that benefits will justify the costs estimated to be imposed by the regulation.

The purpose of a benefit-cost analysis is to provide policy makers and others with detailed information on the economic consequences of the regulatory requirements. The benefit-cost analysis for this rulemaking was conducted using a scenario analysis. The benefit-cost analysis considers a regulation designed to reduce the likelihood of a catastrophic oil spill. The costs are the compliance costs of imposed regulation. If another catastrophic oil spill is prevented, the benefits are the avoided costs associated with a catastrophic oil spill (*e.g.,* reduction in expected natural resource damages owing to the reduction in likelihood of failure).

Avoided cost is an approximation of the ''true'' benefits of avoiding a catastrophic oil spill. A benefits transfer approach is used to estimate the avoided costs. The benefits transfer method estimates economic values by transferring existing benefit calculations from studies already completed for another location or issue to the case at hand. Accordingly, none of the avoided costs used for a hypothetical catastrophic spill rely upon, or should be taken to represent, our estimate for the DWH event.

Three new requirements account for most of the compliance costs imposed by this rulemaking. These are: (1) Use of two independent barriers in each annular flow path; and in the final casing string or liner to prevent hydrocarbon flow in the event of cement failure; (2) Application of negative pressure tests to the production casing string for wells drilled with a subsea BOP; and (3) Testing time for the ROV to close BOP rams after the BOP has been installed on the sea floor. BSEE estimates that these three requirements will impose compliance costs of approximately $118 million per year, representing 91 percent of the total annual compliance costs of $131 million associated with this rulemaking. These cost estimates were developed based on public data sources, BSEE experience, and confidential information provided by several offshore operators and drilling companies. The $131 million estimated annual compliance costs are 29 percent less than the $183 million cost estimated previously for the IFR, largely reflecting a reduced estimate of the time it takes to conduct an ROV function test when the BOP is on the seafloor and lower negative pressure test costs resulting from relaxed testing requirements in the IFR. These reduced costs are partly offset by the requirement that a dual float valve no longer meets the criteria for a mechanical barrier and inclusion of paperwork costs omitted from the estimates in the IFR. See table 4 earlier in this preamble comparing the IFR estimated compliance costs with those estimated in this Final Rule.

On the benefit side, the avoided costs for a representative deepwater blowout resulting in a catastrophic oil spill are estimated to be about $16.3 billion (in 2010 dollars). Most of this amount derives from cleanup and restoration estimates developed by the Department of the Interior, Office of Policy Analysis, using damage costs per barrel measures found in historical spill data (from all sources including pipeline, tanker, and shallow water, as well as from deepwater wells) and from aggregate damage measures contained in the legal settlement documents for past spills applied to a catastrophic deepwater spill of hypothetical size. The rest of this avoided cost amount represents the private costs for blowout containment operations. In sum, three components account for nearly the entire avoided spill cost total: (1) Natural resource damage to habitat and creatures; (2) Infrastructure salvage and cleanup operations of areas soiled by oil; and (3) Containment and well-plugging actions, plus lost hydrocarbons.

We believe the compliance cost estimate of $131 million is closer to the actual cost than the figure used in the IFR because of improved information gathered since deepwater drilling resumed in the GOM in the spring of 2011. On the benefit side, the total avoided cost estimate of $16.3 billion (representing a measure of expected benefits for avoiding a future catastrophic oil spill) has not been revised. The true magnitude of an avoided spill is highly uncertain because of the limited historical data upon which to judge the cost of failure, the disparity between the damages associated with spills of different sizes, locations, and season of occurrence, and owing to the fact that the measure employed reflects only those outlays that we have been able to calculate based primarily upon factors derived from past oil spills. Possible losses from human health effects or reduced property values have not been quantified in this analysis. Moreover, the likelihood of a future blowout leading to a catastrophic oil spill is difficult to quantify because of limited historical data on catastrophic offshore blowouts.

(2) This final rule will not adversely affect competition or State, local, or tribal governments or communities.

(3) This final rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency.

(4) This final rule will not alter the budgetary effects of entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

(5) This final rule will not raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in E.O. 12866.

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. This final rule has been developed in a manner consistent with these requirements.

Regulatory Flexibility Act: Final Regulatory Flexibility Analysis

BSEE has prepared a Final Regulatory Flexibility Analysis (FRFA) in conjunction with this Final Rule. The FRFA is found in Appendix A of the Regulatory Impact Analysis (RIA). As with the analysis under E.O. 12866, the FRFA analyzes the rulemaking, consisting of the IFR as modified by this Final Rule. The Bureau's publication of the IFR did not include a full Initial Regulatory Flexibility Analysis (IRFA) pursuant to the Regulatory Flexibility Act (5 U.S.C. 603). A supplemental IRFA was published on December 23, 2010 (75 FR 80717) with a 30-day comment period which closed on January 24, 2011. The changes from the IRFA are minor and relate to lower total compliance cost estimates for the regulation. The revised cost estimates are the result of changes to the regulatory language from the IFR to this Final Rule and improved estimates of the costs and the operational timeframes required to comply with the regulatory provisions.

This final rule affects lessees, operators of leases, and drilling contractors on the OCS; thus this rule directly impacts small entities. This could include about 130 active Federal oil and gas lessees and more than a dozen drilling contractors and their suppliers. Small entities that operate under this rule are coded under the Small Business Administration's North American Industry Classification System (NAICS) codes 211111, Crude Petroleum and Natural Gas Extraction, and 213111, Drilling Oil and Gas Wells.

For these NAICS code classifications, a small company is one with fewer than 500 employees. Based on these criteria, approximately 65 percent of companies operating on the OCS are considered small companies. Therefore, BSEE has determined that this rulemaking will have an impact on a substantial number of small entities.

We estimate that the rulemaking will impose a recurring operational cost of $131 million each year on operators drilling OCS wells. The rulemaking affects every new well drilled after October 14, 2010; some requirements also apply to wells undergoing completion, workover, or abandonment operations on the OCS. Every operator, both large and small, must meet the same criteria for these operations regardless of company size. However, the overwhelming share of the cost imposed by the rulemaking will fall on the operating companies drilling deepwater wells, which are predominately the larger companies. We estimate that about 81 percent of the total costs will be imposed on deepwater lessees and operators where small businesses only hold 8 percent of the leases and drill 12 percent of the wells. About 19 percent of the total costs will apply to shallow water leases where small companies hold 45 percent of OCS leases and also drill 45 percent of the wells.

Nonetheless, small companies, as both operators and lease-holders, will bear meaningful costs under the rulemaking. Of the annual $131 million in annual cost imposed by the rulemaking, we estimate that $12.7 million will apply to small businesses operating in deepwater and $11.2 million to those operating in shallow water. In total, we estimate that $23.9 million or 18 percent of the rulemaking's cost will be borne by small businesses.

Alternatives to ease impacts on small business were considered and are discussed in the FRFA. The alternatives considered include: different compliance requirements for small entities, alternative BOP testing requirements and periods, performance rather than design standards, and exemption from regulatory requirements. These alternatives are being rejected by BSEE for this rulemaking because of the overriding need to reduce the chance of a catastrophic blowout event. It would not be responsible for a regulator to compromise the safety of offshore personnel and the environment for any entity, including small businesses. Offshore drilling is highly technical and can be hazardous; any delay may increase the interim risk of OCS drilling operations.

Small Business Regulatory Enforcement Fairness Act

This final rule is a major rule under the Small Business Regulatory Enforcement Fairness Act (5 U.S.C. 801 *et seq.*). As with the preceding analyses, this discussion deems the rulemaking to consist of the IFR as modified by this Final Rule. This rulemaking:

(a) Will have an annual effect on the economy of $100 million or more. This rulemaking will affect every new well on the OCS, and every operator, both large and small must meet the same criteria for well construction regardless of company size. This rulemaking may have a significant economic effect on a substantial number of small entities, as discussed in the FRFA. While large companies will bear the majority of these costs, small companies as both leaseholders and contractors supporting OCS drilling operations will be affected.

Considering the new requirements for redundant barriers and new tests, we estimate that this rulemaking will add an average of about $850 thousand to each new deepwater well drilled and completed with a MODU, $230 thousand for each new deepwater well drilled with a platform rig, and $130 thousand for each new shallow water well. While not an insignificant amount, we note this extra recurring cost is around 1 percent for most deep and shallow water wells.

(b) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. The impact on domestic deepwater hydrocarbon production as a result of these regulations is expected to be marginally negative, but the size of the impact is not expected to materially impact world oil markets. The deepwater GOM is an oil province and the domestic crude oil prices are set by the world oil markets. Currently, domestic onshore production is increasing and there is sufficient spare capacity in OPEC to offset any GOM deepwater production decline that could occur as a result of this rulemaking. Therefore, the increase in the price of hydrocarbon products to consumers from the increased cost to drill and operate on the OCS is expected to be minimal.

(c) Will not have significant adverse effects on competition, innovation, or the ability of U.S.-based enterprises to compete with foreign-based enterprises. The requirements will apply to all entities operating on the OCS.

(d) May have adverse effects on employment, investment, and productivity. A meaningful increase in costs as a result of more stringent regulations and increased drilling costs may result in a reduction in the pace of deepwater drilling activity on marginal offshore fields, and reduce investment in our offshore domestic energy resources from what it otherwise will be, thereby reducing employment in OCS and related support industries. The additional regulatory requirements in this rulemaking will increase drilling costs and add to the time it takes to drill deepwater wells. The resulting reduction in profitability of drilling operations may cause some declines in related investment and employment. A typical deepwater well drilled by a MODU may cost $90–$100 million. The added cost of this rulemaking for offshore wells is expected to yield about a 1 percent decrease in productivity.

(e) Does not make accommodations for small business. Not making such accommodations avoids the risk of compromising the safety and environmental protections addressed in this rulemaking. Small businesses actively invest in offshore operations, owning a 12 percent interest in deepwater leases, most often as a minority partner, and 45 percent of shallow water leases. This rulemaking will make it more expensive for all interest holders in OCS leases, and we do not expect a disproportionate impact on small businesses. However, the costs in this rulemaking may contribute to one or more of the following:

(1) Reduce the small business ownership share in individual deepwater leases.

(2) Cause small businesses to target their investments more in shallow water leases.

(3) Cause small businesses to target their investments more in onshore oil and gas operations or other natural resources.

(4) Small businesses may choose to invest or partner in overseas natural resource operations.

(f) May affect small businesses that support offshore oil and gas drilling operations including service, supply, and consulting companies. Because there may be a marginal decrease in offshore drilling activity due to the increased cost and regulatory burden, some businesses that support drilling operations may experience reduced business activity. Some small business may therefore decide to focus more on shallow water or other oil and gas offshore provinces overseas.

(g) May benefit some small businesses. Companies that are involved with inspecting and certifying equipment covered by this rulemaking, as well as consulting companies specializing in safety and offshore drilling, could see long-term growth.

Unfunded Mandates Reform Act of 1995

This Final Rule will not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The Final Rule will not have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) is not required.

Takings Implication Assessment (E.O. 12630)

Under the criteria in E.O. 12630, this rulemaking does not have significant takings implications. The Final Rule is not a governmental action capable of interference with constitutionally protected property rights. A Takings Implication Assessment is not required.

Federalism (E.O. 13132)

Under the criteria in E.O. 13132, this final rule does not have federalism implications. This rulemaking will not substantially and directly affect the relationship between the Federal and State governments. To the extent that State and local governments have a role in OCS activities, this rulemaking will not affect that role. A Federalism Assessment is not required.

Civil Justice Reform (E.O. 12988)

This rulemaking complies with the requirements of E.O. 12988. Specifically, this rulemaking:

(a) Meets the criteria of section 3(a) requiring that all regulations be reviewed to eliminate errors and ambiguity and be written to minimize litigation; and

(b) Meets the criteria of section 3(b)(2) requiring that all regulations be written in clear language and contain clear legal standards.

Consultation With Indian Tribes (E.O. 13175)

Under the criteria in E.O. 13175, we have evaluated this rulemaking and determined that it has no substantial effects on Federally recognized Indian tribes.

Paperwork Reduction Act (PRA)

This Final Rule contains a collection of information that was submitted to and approved by OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). This rule expands existing and adds new regulatory requirements under in 30 CFR 250, subparts D, E, F, and Q based on comments received from the IFR (75 FR 63346). The OMB approved these requirements and assigned OMB Control Number 1014–0020, 5,347 hours (expiration August 31, 2015). The title of the collection of information for this Final Rule is 30 CFR 250, *Increased Safety Measures for Energy Development on the Outer Continental Shelf.*

Respondents primarily are the Federal OCS lessees and operators. The frequency of response varies depending upon the requirement. Responses to this collection of information are mandatory. BSEE will protect proprietary information according to the Freedom of Information Act (5 U.S.C. 552), its implementing regulations (43 CFR 2), 30 CFR 250.197, *Data and information to be made available to the public or for limited inspection,* and 30 CFR part 252, *OCS Oil and Gas Information Program.*

As discussed earlier in the preamble, this final rulemaking is a revision to various sections of the 30 CFR 250 regulations that will amend drilling regulations in subparts D, E, F, and Q. This includes requirements that will implement various safety measures that pertain to drilling, well-completion, well-workovers, and abandoning/decommissioning operations. The information collected will ensure sufficient redundancy in the BOPs; promote the integrity of the well and enhance well-control; and facilitate a culture of safety through operational and personnel management. This Final Rule will promote human safety and environmental protection.

Based on comments received from the IFR (1010–AD68), this rulemaking adds new regulatory requirements and/or expands requirements to those already approved under 30 CFR 250, subparts D, E, F, and Q, as explained in the following paragraphs.

A commenter stated that, where applicable, requirements for drilling, well work-overs, completions, abandonment and/or decommissioning should be consistent. We agreed with the comment, and to be consistent, added new requirements and expanded others in subparts D, E, F, and Q.

For example, in § 250.449(j), when operators submit their test procedures for approval, they must now include how they will test each ROV. We consider the currently approved burden for this requirement to be adequate to include this expanded new information collection (IC) because an operator doing due diligence will have already addressed this requirement in developing its test procedures; the burden will be to submit the procedures to BSEE.

Also, as a logical outgrowth of the IFR and to respond to the comment to make the BOP requirements consistent across various subparts of the BSEE regulations, we added the BOP requirements to subpart Q.

Please note that between the IFR and the Final Rule, as discussed previously, the BSEE was created. Upon creation of the new agency, the OMB-approved collections of information that related to BSEE were transferred from the 1010 to the 1014 numbering system. Also the collection of information pertaining to 30 CFR 250, subpart D, came up for OMB renewal. As per the PRA process, we revised the estimated burdens, per consultations with industry, which included the new requirements of the IFR. Therefore, the subpart D collection that was submitted to, and approved by, OMB included the hour burdens that pertained to the IFR. Accordingly, this analysis *only* addresses the IC burden of the new and/or expanded regulatory requirements imposed by this final rule.

The current regulations on Oil and Gas Drilling Operations and associated IC are located in 30 CFR 250, subpart D. The OMB approved the IC burden of the current subpart D regulations under control number 1014–0018 (expiration 10/31/2014). This Final Rule adds additional regulatory requirements that pertain to subsea and surface BOPs, well casing and cementing, secondary intervention, unplanned disconnects, recordkeeping, well-completion, and well plugging (+363 burden hours).

The current regulations on Oil and Gas Well-Completion Operations and associated IC are located in 30 CFR 250, subpart E. The OMB approved the IC burden of the current subpart E regulations under control number 1014–0004 (expiration 1/31/2014). This Final Rule adds new regulatory requirements to this subpart that pertain to subsea and surface BOPs, secondary intervention, and well-completions (+311 burden hours).

The current regulations on Oil and Gas Well-Workover Operations and associated IC are located in 30 CFR 250, subpart F. The OMB approved the IC burden of the current subpart F regulations under control number 1014–0001 (expiration 1/31/2014). This Final Rule adds new regulatory requirements to this subpart that pertain to subsea and surface BOPs, secondary intervention, unplanned disconnects, and well-workers (+776 burden hours).

The current regulations on Decommissioning Activities and associated IC are located in 30 CFR 250, subpart Q. The OMB approved the IC burden of the current subpart Q regulations under control number 1014–0010 (expiration 12/31/2013). This Final Rule adds new regulatory requirements that refer to information collection requirements that pertain to subsea and surface BOPs, secondary intervention, unplanned disconnects and well workers during the abandonment decommissioning process (+3,897 burden hours).

We note that while Form BSEE–0124, Application for Permit to Modify is housed in 30 CFR 250, subpart D (1014–0018), this form is used in multiple subparts for multiple purposes. The form is also used in 30 CFR 250, subparts E, F, P, and Q—Well-Completions, Well-Workovers, Sulphur Operations, and for Abandonment/Decommissioning functions. While the requirement may be stated as 'submit with your APM', the paperwork burden to fill out the form is in subpart D, while the actual APM submittal of supplementary and supporting documents and/or information that pertains to the job function is in the specific subpart.

When this rule becomes effective, BSEE will incorporate the 30 CFR 250, subparts D, E, F, and Q paperwork burdens into their respective primary collections: 1014–0018, 1014–0004, 1014–0001, and 1014–0010 respectively.

The following table provides a breakdown of the new burdens.

BURDEN TABLE

Citation 30 CFR 250	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours (rounded)
	Subpart D			
410–418; 420(a)(6); 423(b)(3), (c)(3); 449(j), (k)(1); 456(j) plus various references in subparts A, B, D, E, H, P, Q.	Apply for permit to drill APD (Form BSEE–0123) that includes any/all supporting documentation/evidence [including, but not limited to, test results, calculations, pressure integrity, verifications, procedures, criteria, qualifications, etc.] and requests for various approvals required in subpart D (including §§ 250.424, 425, 427, 428, 432, 442(c), 447, 448(c), 451(g), 456(a)(3), (f), 460, 490(c)) and submitted via the form; upon request, make available to BSEE.	Burden covered under 1014–0018		0
449(j); 460; 465; 514(d); 515; 517(d)(8–9); 614(d); 615; 617(h)(1–2); 1704(g); 1707(d), (h)(1–2); 1709; 1712; 1721(h).	Provide revised plans and the additional supporting information required by the cited regulations [test results, calculations, verifications, procedures, criteria, qualifications, etc.] when you submit an Application for Permit to Modify (APM) (Form BSEE–0124) to BSEE for approval.	Burden covered under 1014–0018		0
416(g)(2)	Provide 72 hour advance notice of location of shearing ram tests or inspections; allow BSEE access to witness testing, inspections and information verification.	Burden covered under 1014–0018		0
416(g)(2)	Submit evidence that demonstrates that the Registered Professional Engineer/firm has the expertise and experience necessary to perform the verification(s); allow BSEE access to witness testing; verify info submitted to BSEE.	0.25	700 submittals	175
420(b)(3)	Submit documentation of two independent barriers after installation with your EOR.	Burden covered under 1014–0018		0
420(b)(3)	Request approval for alternative options to installing barriers	0.25	25 requests	7
423(a)	Request alternative approval for other pressure casing test pressures	Burden covered under 1010–0114		0
423(a)	Request and receive approval from BSEE District Manager for repair	0.5	88 requests	44
423(b)(3), (c)(4)	Document pressure casing test results and make available to BSEE upon request.	Burden covered under 1014–0018		0
423(c)(5)	Immediately contact BSEE District Manager when problem corrected due to failed negative pressure test; submit a description of corrected action taken; and receive approval from BSEE District Manager to retest.	1	14 notifications	14
423(c)(8)	Submit documentation of successful negative pressure test in the EOR (Form BSEE–0125).	2	45 submittals	90
442(f)(3)	Demonstrate that your secondary control system will function properly	5	1 validation	5
446(a)	Document BOP maintenance and inspection procedures used; record results of BOP inspections and maintenance actions; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	Burden covered under 1014–0018		0
449(j)(2)	Notify BSEE District Manager at least 72 hours prior to stump/initial test on seafloor.	0.25	110 notifications	28
449(j)(3) *	Document all ROV intervention function test results including how you test each ROV functions; make available to BSEE upon request.	Burden covered under 1014–0018		0
456(j)	Request approval from the BSEE District Manager to displace kill-weight fluids to an underbalanced state; submit detailed written procedures with your APD/APM.	Burden covered under 1014–0018		0
Subtotal D			983 responses	363

BURDEN TABLE—Continued

Citation 30 CFR 250	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours (rounded)
Subpart E				
514(d)	Request approval from the BSEE District Manager to displace kill-weight fluids to an underbalanced state; submit detailed written procedures with your APM.	2	60 requests	120
515	Submit a description of your BOP and its components; schematic drawings; independent third-party verification and all supporting information (evidence showing appropriate licenses, has expertise/experience necessary to perform required verifications, etc) with your APM.	15	12 submittals	180
515(e)(2)(ii)	Allow BSEE access to witness testing, inspections, and information verification. Notify BSEE District Manager at least 72 hours prior to shearing ram tests.	0.25	12 notifications	3
517(d)(8)*	Function test ROV interventions on your subsea BOP stack; document all test results, including how you test each ROV function; submit procedures with your APM for BSEE District Manager approval; make available to BSEE upon request.	Burden covered under 1014–0004		0
517(d)(8)(ii)	Notify BSEE District Manager at least 72 hours prior to stump/initial test on seafloor.	0.25	32 notifications	8
517(d)(9)	Document all autoshear and deadman test results and submit test procedures with your APM for BSEE Manager approval; make available to BSEE upon request.	Burden covered under 1014–0004		0
517(g)(l)	Document BOP inspection procedures used; record results of BOP inspection actions; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	Burden covered under 1014–0004		0
517(g)(2)	Request alternative method/frequency to inspect a marine riser	Burden covered under 1010–0114		0
517(h)	Document the procedures used for BOP maintenance/quality management; record results; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	Burden covered under 1014–0004		0
Subtotal E			116 responses	311
Subpart F				
614(d)	Request approval from the BSEE District Manager to displace kill-weight fluids to an underbalanced state; submit detailed written procedures with your APM.	2	80 requests	160
615	Submit a description of your BOP and its components; schematic drawings; independent third-party verification and all supporting information (evidence showing appropriate licenses, has expertise/experience necessary to perform required verifications, etc) with your APM.	15	40 submittals	600
615(e)(2)(ii)	Allow BSEE access to witness testing, inspections, and information verification. Notify BSEE District Manager at least 72 hours prior to shearing ram tests.	0.25	12 notifications	5
617(h)(l) *	Document all test results of your ROV intervention functions including how you test each ROV function; submit test procedures with your APM for BSEE District Manager approval; make available to BSEE upon request.	Burden covered under 1014–0001		0
617(h)(1)(ii)	Notify BSEE District Manager at least 72 hours prior to stump/initial test on seafloor.	0.25	44 notifications	11
617(h)(2) *	Document all autoshear and deadman test results; submit test procedures with your APM for BSEE District Manager approval; make available to BSEE upon request.	Burden covered under 1014–0001		0
618(a)(l)	Document the procedures used for BOP inspections; record results; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	Burden covered under 1014–0001		0
618(a)(2)	Request approval to use alternative method to inspect a marine riser	Burden covered under 1010–0114		0
618(b)	Document the procedures used for BOP maintenance; record results; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	Burden covered under 1014–0001		0
Subtotal F			176 responses	776
Subpart Q				
1705	Submit a description of your BOP and its components; schematic drawings; independent third-party verification and all supporting information (evidence showing appropriate licenses, has expertise/experience necessary to perform required verifications, etc) with your APM.	15	200 submittals	3,000
1705(e)(2)(ii)	Allow BSEE access to witness testing, inspections, and information verification. Notify BSEE District Manager at least 72 hours prior to shearing ram tests.	0.25	12 submittals	3

BURDEN TABLE—Continued

Citation 30 CFR 250	Reporting & recordkeeping requirement	Hour burden	Average number of annual responses	Annual burden hours (rounded)
1706(a)	Request approval of well abandonment operations; procedures indicating how the annular preventer will be utilized and how pressure limitations will be applied during each mode of pressure control, with your APM.	0.25	200 requests	50
1706(f)(4)	Request approval of the BSEE District Manager to conduct operations without downhole check values; describe procedures/equipment in APM.	1	50 requests	50
1707(a)(2)	Request approval from BSEE District Manager to test annular BOP less than 70 percent.	0.25	6 requests	2
1707(b)(2)	State reason for postponing test in operations logs	0.25	30 reasons	8
1707(b)(2)	Request approval from BSEE District Manager for alternate test frequencies if condition/BOP warrant.	0.25	5 requests	2
1707(f)	Request alternative method to record test pressures	0.25	25 requests	7
1707(f)	Record test pressures during BOP and coiled tubing on a pressure chart or w/digital recorder; certify charts are correct.	1	200 records/certifications	200
1707(g)	Record or reference in operations log all pertinent information listed in this requirement; make all documents pertaining to BOP tests, actuations and inspections available for BSEE review at facility for duration of well abandonment activity; retain all records for 2 years at a location conveniently available for the BSEE District Manager.	0.5	200 records	100
1707(h)(1)	Submit test procedures with your APM for BSEE District Manager approval.	1	50 submittals	50
1707(h)(1)(ii)	Document all ROV intervention test results; make available to BSEE upon request.	0.5	50 records	25
1707(h)(2)(ii)	Document all autoshear and deadman function test results; make available to BSEE upon request.	0.25	50 records	13
1708(a), (b)	Document BOP inspection and maintenance procedures used; record results of BOP inspections and maintenance actions; maintain records for 2 years or longer if directed by BSEE; make available to BSEE upon request.	1	25 records	25
1708(a)	Request alternative method to inspect marine risers	0.25	5 requests	2
1709	Request approval from the BSEE District Manager to displace kill-weight fluids in an unbalanced state; submit detailed written procedures with your APM.	2	80 requests	160
1712(g); 1721(h)	Submit with your APM, Registered Professional Engineer certification	Burden covered under 1014–0018		0
1712(g)*; 1721(h)*	Submit evidence from the Registered Professional Engineer/firm of the well abandonment design and procedures; plugs in the annuli meet requirements of § 250.1715; 2 independent barriers etc; has the expertise and experience necessary to perform the verification(s), submit with the APM.	1	200	200
Total Q			1,388 responses	3,897
Grand Total			2,663 Responses	5,347

An agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public may comment, at any time, on the accuracy of the IC burden in this rule and may submit any comments to the Department of the Interior; Bureau of Safety and Environmental Enforcement; Regulations Development Branch; Mail Stop HE–3314; 381 Elden Street; Herndon, Virginia 20170–4817.

National Environmental Policy Act of 1969

We have prepared a supplemental environmental assessment to determine whether this rule will have a significant impact on the quality of the human environment under the National Environmental Policy Act of 1969. This rule does not constitute a major Federal action significantly affecting the quality of the human environment. A detailed statement under the National Environmental Policy Act of 1969 is not required because we reached a Finding of No Significant Impact (FONSI). A copy of the FONSI and Supplemental Environmental Assessment can be viewed at *www.Regulations.gov* (use the keyword/ID ''BSEE–2012–0002'').

Data Quality Act

In developing this rulemaking, we did not conduct or use a study, experiment, or survey requiring peer review under the Data Quality Act (Pub. L. 106–554, app. C § 515, 114 Stat. 2763, 2763A–153–154).

Effects on the Energy Supply (E.O. 13211)

This rulemaking is a significant rule and is subject to review by the Office of Management and Budget under E.O. 12866. This rulemaking does have an effect on energy supply, distribution, or use because its provisions may delay development of some OCS oil and gas resources. The delay stems from the extra drill time and cost imposed on new wells which will marginally slow exploration and development operations. We estimate an average delay of 1 day and cost of $820 thousand for most deepwater wells in the GOM.

Increased imports or inventory drawdowns should compensate for most of the delay or reduction in domestic production. The recurring costs imposed on new drilling by this rulemaking are very small (1 percent) relative to the cost of drilling an OCS well. In view of the high risk-reward associated with deepwater exploration in general, we do not expect this small regulatory surcharge from this rulemaking to result in meaningful reduction in discoveries. Thus, we expect the net change in supply associated with this rulemaking will cause only a very slight increase in oil and gas prices relative to what they otherwise would have been. Normal volatility in both oil and gas market prices overshadow these rule-related price effects, so we consider this an insignificant effect on energy supply and price.

List of Subjects in 30 CFR Part 250

Administrative practice and procedure, Continental shelf, Incorporation by reference, Oil and gas exploration, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements.

Dated: August 9, 2012.

Ned Farquhar,

Deputy Assistant Secretary—Land and Minerals Management.

For the reasons stated in the preamble, the Bureau of Safety and Environmental Enforcement (BSEE) is amending 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

■ 1. The authority citation for part 250 continues to read as follows:

Authority: 30 U.S.C. 1751, 31 U.S.C. 9701, 43 U.S.C. 1334.

■ 2. In part 250, revise all references to ''glory hole'' to read ''well cellar''.

■ 3. Amend § 250.125(a), by revising entries (8) and (9) in the table to read as follows:

§ 250.125 Service fees.

(a) * * *

Service—processing of the following	Fee amount	30 CFR citation
* *	* * *	* *
(8) Application for Permit to Drill (APD; Form BSEE–0123).	$1,959 for initial applications only; no fee for revisions.	§ 250.410(d); § 250.513(b); § 250.1617(a).
(9) Application for Permit to Modify (APM; Form BSEE–0124).	$116	§ 250.465(b); § 250.513(b); § 250.613(b); § 250.1618(a); § 250.1704(g).
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■ 4. Amend § 250.198 by revising paragraphs (a)(3), (h)(63), and (h)(78) to read as follows:

§ 250.198 Documents incorporated by reference.

(a) * * *

(3) The effect of incorporation by reference of a document into the regulations in this part is that the incorporated document is a requirement. When a section in this part incorporates all of a document, you are responsible for complying with the provisions of that entire document, except to the extent that the section which incorporates the document by reference provides otherwise. When a section in this part incorporates part of a document, you are responsible for complying with that part of the document as provided in that section.

* * * * *

(h) * * *

(63) API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004; incorporated by reference at §§ 250.442, 250.446, 250.517, 250.618, and 250.1708,

* * * * *

(78) API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010; incorporated by reference at § 250.415(f).

* * * * *

■ 5. Amend § 250.415 by revising paragraphs (f) to read as follows:

§ 250.415 What must my casing and cementing programs include?

* * * * *

(f) A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition (as incorporated by reference in § 250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5).

■ 6. Amend § 250.416 by revising paragraphs (e), (f), and (g) to read as follows:

§ 250.416 What must I include in the diverter and BOP descriptions?

* * * * *

(e) Independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for MASP;

(f) When you use a subsea BOP stack or surface BOP stack on a floating facility, independent third-party verification that shows:

(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;

(3) The BOP stack will operate in the conditions in which it will be used; and

(g) The qualifications of the independent third-party referenced in paragraphs (e) and (f) of this section:

(1) The independent third-party in this section must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

(2) You must:

(i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications.

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the BSEE District Manager at least 72 hours in advance.

■ 7. Amend § 250.418 by revising paragraphs (g) and (i) to read as follows:

§ 250.418 What additional information must I submit with my APD?

* * * * *

(g) A request for approval if you plan to wash out below the mudline or displace some cement to facilitate casing removal upon well abandonment;

* * * * *

(i) Descriptions of qualifications required by § 250.416(g) of the independent third-party; and

* * * * *

■ 8. Amend § 250.420 by revising paragraphs (a)(6) and (b)(3) to read as follows:

§ 250.420 What well casing and cementing requirements must I meet?

* * * * *

(a) * * *

(6)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and § 250.423. Submit this certification with your APD (Form BSEE–0123).

(ii) You must have the registered professional engineer involved in the casing and cementing design process.

(iii) The registered professional engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification.

(b) * * *

(3) On all wells that use subsea BOP stacks, you must include two independent barriers, including one mechanical barrier, in each annular flow path (examples of barriers include, but are not limited to, primary cement job and seal assembly). For the final casing string (or liner if it is your final string), you must install one mechanical barrier in addition to cement to prevent flow in the event of a failure in the cement. A dual float valve, by itself, is not considered a mechanical barrier. These barriers cannot be modified prior to or during completion or abandonment operations. The BSEE District Manager may approve alternative options under § 250.141. You must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE–0125).

* * * * *

■ 9. Revise § 250.423 to read as follows:

§ 250.423 What are the requirements for pressure testing casing?

(a) The table in this section describes the minimum test pressures for each string of casing. You may not resume drilling or other down-hole 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 investigate the cause and receive approval from the appropriate BSEE District Manager for the repair to resolve the problem ensuring that the casing will provide a proper seal. The BSEE District Manager may approve or require other casing test pressures.

Casing type	Minimum test pressure
(1) Drive or Structural	Not required.
(2) Conductor	200 psi.
(3) Surface, Intermediate, and Production.	70 percent of its minimum internal yield.

(b) You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(1) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string.

(2) 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.

(3) 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 liner.

(i) You must submit for approval with your APD, test procedures and criteria for a successful test.

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

(c) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems. The BSEE 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.

(1) You must perform a negative pressure test on your final casing string or liner.

(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.

(3) You must submit for approval with your APD, test procedures and criteria for a successful 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.

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

(5) 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 contact the appropriate BSEE District Manager.

(ii) Submit a description of the corrective action taken and you must receive approval from the appropriate BSEE District Manager for the retest.

(6) You must have two barriers in place, as required in § 250.420(b)(3), prior to performing the negative pressure test.

(7) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE–0125).

■ 10. Amend § 250.428 by revising paragraph (c) to read as follows:

§ 250.428 What must I do in certain cementing and casing situations?

* * * * *

If you encounter the following situation . . .	Then you must . . .
* * * *	* * *
(c) Have indication of inadequate cement job (such as, but not limited to, lost returns, cement channeling, gas cut mud, or failure of equipment).	(1) Run a temperature survey; (2) Run a cement evaluation log; or (3) Use a combination of these techniques.

If you encounter the following situation . . .	Then you must . . .
* * * * * * *	

■ 11. Amend § 250.442 by removing paragraph (l) and revising paragraphs (a), (e), and (f) to read as follows:

§ 250.442 What are the requirements for a subsea BOP system?

* * * * *

When drilling with a subsea BOP system, you must . . .	Additional requirements . . .
(a) Have at least four remote-controlled, hydraulically operated BOPs ..	You must have at least one annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressures.
* * * * * * *	
(e) Maintain an ROV and have a trained ROV crew on each drilling rig 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.	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.
(f) Provide autoshear and deadman systems for dynamically positioned rigs.	(1) *Autoshear system* means a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the LMRP. When the autoshear is armed, a disconnect of the LMRP closes, at a minimum, one set of blind-shear rams. This is considered a ''rapid discharge'' system. (2) *Deadman System* means a safety system that is designed to automatically close, at a minimum, one set of blind-shear rams 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. (3) You may also have an acoustic system as a secondary control system. If you intend to install an acoustic control system, you must demonstrate to BSEE as part of the information submitted under § 250.416 that the acoustic system will function in the proposed environment and conditions.
* * * * * * *	

■ 12. Amend § 250.443 by revising paragraph (g) to read as follows:

§ 250.443 What associated systems and related equipment must all BOP systems include?

* * * * *

(g) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated wellhead pressure.

■ 13. Amend § 250.446 by revising paragraph (a) to read as follows:

§ 250.446 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions properly. The BOP maintenance and inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, record the results of your BOP inspections and maintenance actions, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE;

* * * * *

■ 14. Amend § 250.449 by revising paragraphs (b), (j), and (k) to read as follows:

§ 250.449 What additional BOP testing requirements must I meet?

* * * * *

(b) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test.

* * * * *

(j) Test all ROV intervention functions on your subsea BOP stack during the stump test. Each ROV must be fully compatible with the BOP stack ROV intervention panels. You must also test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab. You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for BSEE District Manager approval. You must:

(1) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams, one set of blind-shear rams, and unlatching the Lower Marine Riser Package (LMRP);

(2) Notify the appropriate BSEE District Manager a minimum of 72 hours prior to the stump test and initial test on the seafloor; and

(3) Document all your test results and make them available to BSEE upon request;

(k) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system and verify closure of at least one set of blind-shear rams during the initial test on the seafloor. 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.

(1) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include documentation of the controls and circuitry of the system utilized during each test. The procedure must also describe how the ROV will be utilized during this operation.

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

■ 15. Amend § 250.451 by adding paragraph (j) to read as follows:

§ 250.451 What must I do in certain situations involving BOP equipment or systems?

* * * * *

If you encounter the following situation . . .	Then you must . . .
* * *	* * * *
(j) Need to remove the BOP stack	Have a minimum of two barriers in place prior to BOP removal. The BSEE District Manager may require additional barriers.

■ 16. Amend § 250.456 by revising paragraph (j) to read as follows:

§ 250.456 What safe practices must the drilling fluid program follow?

* * * * *

(j) Before you displace kill-weight fluid from the wellbore and/or riser to an underbalanced state, you must obtain approval from the BSEE District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers,

(2) Tests you will conduct to ensure integrity of independent barriers,

(3) BOP procedures you will use while displacing kill-weight fluids, and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore; and

* * * * *

■ 17. Amend § 250.513 by:

■ a. Redesignating paragraphs (b)(4) through (b)(5) as (b)(5) through (b)(6), and

■ b. Adding a new paragraph (b)(4) to read as follows:

§ 250.513 Approval and reporting of well-completion operations.

* * * * *

(b) * * *

(4) All applicable information required in § 250.515.

* * * * *

■ 18. Amend § 250.514 by adding paragraph (d) to read as follows:

§ 250.514 Well-control fluids, equipment, and operations.

* * * * *

(d) Before you displace kill-weight fluid from the wellbore and/or riser to an underbalanced state, you must obtain approval from the BSEE District Manager. To obtain approval, you must submit with your APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers,

(2) Tests you will conduct to ensure integrity of independent barriers,

(3) BOP procedures you will use while displacing kill-weight fluids, and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

■ 19. Redesignate §§ 250.515 through 250.530 as §§ 250.516 through 250.531.

■ 20. Add new § 250.515 to read as follows:

§ 250.515 What BOP information must I submit?

For completion operations, your APM must include the following BOP descriptions:

(a) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(b) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

(c) Independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used, and calculations of shearing capacity of all pipe to be used in the well including correction for maximum anticipated surface pressure;

(d) When you use a subsea BOP stack, independent third-party verification that shows:

(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;

(3) The BOP stack will operate in the conditions in which it will be used; and

(e) The qualifications of the independent third-party referenced in paragraphs (c) and (d) of this section:

(1) The independent third-party in this section must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

(2) You must:

(i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications; and

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the BSEE District Manager at least 72 hours in advance.

■ 21. Amend newly redesignated § 250.517 by revising paragraphs (d)(2), (d)(8), (d)(9), (g), and (h) to read as follows:

§ 250.517 Blowout preventer system tests, inspections, and maintenance.

* * * * *

(d) * * *

(2) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system. You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test.

* * * * *

(8) Test all ROV intervention functions on your subsea BOP stack during the stump test. Each ROV must be fully compatible with the BOP stack ROV intervention panels. You must also test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab. You must submit test procedures, including how you will test each ROV function, with your APM for BSEE District Manager approval. You must:

(i) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams, one set of blind-shear rams, and unlatching the LMRP;

(ii) Notify the appropriate BSEE District Manager a minimum of 72 hours prior to the stump test and initial test on the seafloor;

(iii) Document all your test results and make them available to BSEE upon request; and

(9) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system and verify closure of at least one set of blind-shear rams during the initial test on the seafloor. 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. You must:

(i) Submit test procedures with your APM for BSEE District Manager approval. The procedures for these function tests must include documentation of the controls and circuitry of the system utilized during each test. The procedure must also describe how the ROV will be utilized during this operation.

(ii) Document all your test results and make them available to BSEE upon request.

* * * * *

(g) *BOP inspections.* (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.10 and 18.10 described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

(2) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system and marine riser at least once every 3 days if weather and sea conditions permit. You may use television cameras to inspect subsea equipment. The BSEE District Manager may approve alternate methods and frequencies to inspect a marine riser.

* * * * *

(h) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

* * * * *

■ 22. Amend § 250.613 by:

a. Redesignating paragraphs (b)(3) through (b)(4) as (b)(4) through (b)(5), and

b. Adding a new paragraph (b)(3) to read as follows:

§ 250.613 Approval and reporting of well-workover operations.

* * * * *

(b) * * *

(3) All information required in § 250.615.

* * * * *

■ 23. Amend § 250.614 by adding new paragraph (d) to read as follows:

§ 250.614 Well-control fluids, equipment, and operations.

* * * * *

(d) Before you displace kill-weight fluid from the wellbore and/or riser to an underbalanced state, you must obtain approval from the BSEE District Manager. To obtain approval, you must submit with your APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers,

(2) Tests you will conduct to ensure integrity of independent barriers,

(3) BOP procedures you will use while displacing kill weight fluids, and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

■ 24. Redesignate §§ 250.615 through 250.619 as §§ 250.616 through 250.620.

■ 25. Add new § 250.615 to read as follows:

§ 250.615 What BOP information must I submit?

For well-workover operations, your APM must include the following BOP descriptions:

(a) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(b) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

(c) Independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for under maximum anticipated surface pressure;

(d) When you use a subsea BOP stack, independent third-party verification that shows:

(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;

(3) The BOP stack will operate in the conditions in which it will be used; and

(e) The qualifications of the independent third-party referenced in paragraphs (c) and (d) of this section:

(1) The independent third-party in this section must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

(2) You must:

(i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications.

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the BSEE District Manager at least 72 hours in advance.

* * * * *

■ 26. Amend newly redesignated § 250.617 by revising paragraph (h) to read as follows:

§ 250.617 Blowout preventer system testing, records, and drills.

* * * * *

(h) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system. You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. You must:

(1) Test all ROV intervention functions on your subsea BOP stack during the stump test. Each ROV must be fully compatible with the BOP stack ROV intervention panels. You must also test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab. You must submit test procedures, including how you will test each ROV function, with your APM for BSEE District Manager approval. You must:

(i) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams, one set of blind-shear rams, and unlatching the LMRP;

(ii) Notify the appropriate BSEE District Manager a minimum of 72 hours prior to the stump test and initial test on the seafloor;

(iii) Document all your test results and make them available to BSEE upon request; and

(2) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system and verify closure of at least one set of blind-shear rams during the initial test on the seafloor. 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. You must:

(i) Submit test procedures with your APM for BSEE District Manager approval. The procedures for these function tests must include documentation of the controls and circuitry of the system utilized during each test. The procedure must also describe how the ROV will be utilized during this operation.

(ii) Document the results of each test and make them available to BSEE upon request.

■ 27. Revise § 250.618 to read as follows:

§ 250.618 What are my BOP inspection and maintenance requirements?

(a) *BOP inspections.* (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.10 and 18.10 described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

(2) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system and marine riser at least once every 3 days if weather and sea conditions permit. You may use television cameras to inspect subsea equipment. The BSEE District Manager may approve alternate methods and frequencies to inspect a marine riser.

(b) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

■ 28. Amend § 250.1500 by revising the definition for ''Well-control'' to read as follows:

§ 250.1500 Definitions

* * * * *

Well-control means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. Well-control applies to drilling, well-completion, well-workover, abandonment, and well-servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment.

* * * * *

■ 29. Amend § 250.1704 by revising paragraph (g) to read as follows:

§ 250.1704 When must I submit decommissioning applications and reports?

* * * * *

Decommissioning applications and reports	When to submit	Instructions
* *	* * *	* *
(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.	(1) Before you temporarily abandon or permanently plug a well or zone	(i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations include information required under § 250.1705.
	(2) Within 30 days after you plug a well	Include information required under § 250.1717.
	(3) Before you install a subsea protective device.	Refer to § 250.1722(a).
	(4) Within 30 days after you complete a protective device trawl test	Include information required under § 250.1722(d).
	(5) Before you remove any casing stub or mud line suspension equipment and any subsea protective device.	Refer to § 250.1723.
	(6) Within 30 days after you complete site clearance verification activities	Include information required under § 250.1743(a).

■ 30. Add § 250.1705 to read as follows:

§ 250.1705 What BOP information must I submit?

If you plan to use a BOP for abandonment operations, your decommissioning application must include the following BOP descriptions:

(a) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(b) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

(c) Independent third-party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for Maximum Anticipated Surface Pressure (MASP);

(d) When you use a subsea BOP stack, independent third-party verification that shows:

(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;

(3) The BOP stack will operate in the conditions in which it will be used; and

(e) The qualifications of the independent third-party referenced in paragraphs (c) and (d) of this section including evidence that:

(1) The independent third-party in this section is a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

(2) You must:

(i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications.

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the BSEE District Manager at least 72 hours in advance.

■ 31. Add § 250.1706 to read as follows:

§ 250.1706 What are the requirements for blowout prevention equipment?

If you use a BOP for any well abandonment operations, your BOP must meet the following requirements:

(a) The BOP system, system components, and related well-control equipment must be designed, used, maintained, and tested in a manner necessary to assure well-control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components must exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, you must submit with Form BSEE–0124, requesting approval of the well abandonment operations, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well abandonment operations with the tree removed must meet the appropriate standards from the following table:

When . . .	The minimum BOP stack must include . . .
(1) The expected pressure is less than 5,000 psi,	Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.
(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings,	Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.
(3) You handle multiple tubing strings simultaneously,	Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.
(4) You use a tapered drill string,	(i) At least one set of pipe rams that are capable of sealing around each size of drill string.

When . . .	The minimum BOP stack must include . . .
	(ii) If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. (iii) You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a subsea BOP stack,	The requirements in § 250.442(a) of this part.

(c) The BOP systems for well abandonment operations with the tree removed must be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed;

(3) Locking devices for the pipe-ram preventers;

(4) At least one remote BOP-control station and one BOP-control station on the rig floor; and

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line must be remotely controlled. At least one of the valves on the kill line must be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed, provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment must have a pressure rating at least equivalent to the ram preventers. You must install the choke line above the bottom ram and may install the kill line below the bottom ram.

(d) The minimum BOP system components for well abandonment operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string, i.e., small-tubing operations, must include the following:

(1) Two sets of pipe rams, and

(2) One set of blind rams.

(e) The subsea BOP system for well abandonment operations must meet the requirements in § 250.442 of this part.

(f) For coiled tubing operations with the production tree in place, you must meet the following minimum requirements for the BOP system:

(1) BOP system components must be in the following order from the top down:

BOP system when expected surface pressures are less than or equal to 3,500 psi	BOP system when expected surface pressures are greater than 3,500 psi	BOP system for wells with returns taken through an outlet on the BOP stack
(i) Stripper or annular-type well-control component,	Stripper or annular-type well-control component,	Stripper or annular-type well-control component.
(ii) Hydraulically-operated blind rams,	Hydraulically-operated blind rams,	Hydraulically-operated blind rams.
(iii) Hydraulically-operated shear rams,	Hydraulically-operated shear rams,	Hydraulically-operated shear rams.
(iv) Kill line inlet,	Kill line inlet,	Kill line inlet.
(v) Hydraulically-operated two-way slip rams,	Hydraulically-operated two-way slip rams,	Hydraulically-operated two-way slip rams.
(vi) Hydraulically-operated pipe rams,	Hydraulically-operated pipe rams.	Hydraulically-operated pipe rams.
	Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical,	A flow tee or cross.
		Hydraulically-operated pipe rams.
		Hydraulically-operated blind-shear rams on wells with surface pressures >3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical.

(2) You may use a set of hydraulically-operated combination rams for the blind rams and shear rams.

(3) You may use a set of hydraulically-operated combination rams for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing well abandonment operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE–0124, Application for Permit to Modify, and have it approved by the BSEE District Manager.

(5) You must have a kill line and a separate choke line. You must equip each line with two full-opening valves and at least one of the valves must be remotely controlled. You may use a manual valve instead of the remotely controlled valve on the kill line if you install a check valve between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and you must install them between the well-control stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. You must not use the kill line inlet on the BOP stack for taking fluid returns from the wellbore.

(6) You must have a hydraulic-actuating system that provides sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure, without assistance from a charging system.

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well-control stack and the first full-opening valve on the choke line and the kill line.

(g) The minimum BOP system components for well abandonment operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, i.e., snubbing operations, must include the following:

(1) One set of pipe rams hydraulically operated, and

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool.

(h) An inside BOP or a spring-loaded, back-pressure safety valve, and an essentially full-opening, work-string safety valve in the open position must be maintained on the rig floor at all times during well abandonment operations when the tree is removed or during well abandonment operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve must be readily available. Proper connections must be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

■ 32. Add § 250.1707 to read as follows:

§ 250.1707 What are the requirements for blowout preventer system testing, records, and drills?

(a) *BOP pressure tests.* When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each component. You must conduct the low-pressure test before the high-pressure test. For purposes of this section, BOP system components include ram-type BOP's, related control equipment, choke and kill lines, and valves, manifolds, strippers, and safety valves. Surface BOP systems must be pressure tested with water.

(1) *Low pressure tests.* You must successfully test all BOP system components to a low pressure between 200 and 300 psi. Any initial pressure equal to or greater than 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero before starting the test.

(2) *High pressure tests.* You must successfully test all BOP system components to the rated working pressure of the BOP equipment, or as otherwise approved by the BSEE District Manager. You must successfully test the annular-type BOP at 70 percent of its rated working pressure or as otherwise approved by the BSEE District Manager.

(3) *Other testing requirements.* You must test variable bore pipe rams against the largest and smallest sizes of tubulars in use (jointed pipe, seamless pipe) in the well.

(b) You must test the BOP systems at the following times:

(1) When installed;

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations must be suspended until the nonfunctional system is operable. The test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams must be tested at least once every 30 days during operation. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests must be conducted as soon as possible and before normal operations resume. The reason for postponing testing must be entered into the operations log. The BSEE District Manager may require alternate test frequencies if conditions or BOP performance warrant.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) All personnel engaged in well abandonment operations must participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) You may conduct a stump test for the BOP system on location. A plan describing the stump test procedures must be included in your Application for Permit to Modify, Form BSEE–0124, and must be approved by the BSEE District Manager.

(e) You must test the coiled tubing connector to a low pressure of 200 to 300 psi, followed by a high pressure test to the rated working pressure of the connector or the expected surface pressure, whichever is less. You must successfully pressure test the dual check valves to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less.

(f) You must record test pressures during BOP and coiled tubing tests on a pressure chart, or with a digital recorder, unless otherwise approved by the BSEE District Manager. The test interval for each BOP system component must be 5 minutes, except for coiled tubing operations, which must include a 10 minute high-pressure test for the coiled tubing string. Your representative at the facility must certify that the charts are correct.

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers must be recorded in the operations log. The BOP tests must be documented in accordance with the following:

(1) The documentation must indicate the sequential order of BOP and auxiliary equipment testing, the pressure, and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test must be identified in the operations log. For a subsea system, the pod used during the test must be identified in the operations log.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities, must be noted in the operations log.

(4) Documentation required to be entered in the operations log may instead be referenced in the operations log. You must make all records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections, available for BSEE review at the facility for the duration of well abandonment activity. Following completion of the well abandonment activity, you must retain all such records for a period of two years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the BSEE District Manager.

(h) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling fluids to conduct subsequent tests of a subsea BOP system. You must stump test the subsea BOP within 30 days of the initial test on the seafloor. You must:

(1) Test all ROV intervention functions on your subsea BOP stack during the stump test. Each ROV must be fully compatible with the BOP stack ROV intervention panels. You must also test and verify closure of at least one set of rams during the initial test on the seafloor. You must submit test procedures, including how you will test each ROV function, with your APM for

BSEE District Manager approval. You must:

(i) Ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams and one set of blind-shear rams and unlatching the LMRP;

(ii) Document all your test results and make them available to BSEE upon request; and

(2) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system and verify closure of at least one set of blind-shear rams during the initial test on the seafloor. 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. You must:

(i) Submit test procedures with your APM for BSEE District Manager approval. The procedures for these function tests must include documentation of the controls and circuitry of the system utilized during each test. The procedure must also describe how the ROV will be utilized during this operation.

(ii) Document the results of each test and make them available to BSEE upon request.

■ 33. Add § 250.1708 to read as follows:

§ 250.1708 What are my BOP inspection and maintenance requirements?

(a) *BOP inspections.* (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.10 and 18.10 described in API RP 53, document the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

(2) You must visually inspect your BOP system and marine riser at least once every 3 days if weather and sea conditions permit. You may use television cameras to inspect this equipment. The BSEE District Manager may approve alternate methods and frequencies to inspect a marine riser.

(b) *BOP maintenance.* You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, document the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

■ 34. Add § 250.1709 to read as follows:

§ 250.1709 What are my well-control fluid requirements?

Before you displace kill-weight fluid from the wellbore and/or riser to an underbalanced state, you must obtain approval from the BSEE District Manager. To obtain approval, you must submit with your APM, your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(a) Number and type of independent barriers, as described in § 250.420(b)(3), that are in place for each flow path that requires such barriers,

(b) Tests you will conduct to ensure integrity of independent barriers,

(c) BOP procedures you will use while displacing kill weight fluids, and

(d) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

■ 35. Amend § 250.1712 by revising paragraph (g) to read as follows:

§ 250.1712 What information must I submit before I permanently plug a well or zone?

* * * * *

(g) Certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements in the table in § 250.1715. In addition to the requirements of § 250.1715, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM (Form BSEE–0124).

■ 36. Amend § 250.1715 by adding paragraph (a)(11) to read as follows:

§ 250.1715 How must I permanently plug a well?

(a) * * *

If you have . . .	Then you must use . . .
* * * *	* * *
(11) Removed the barriers required in § 250.420(b)(3) for the well to be completed.	Two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3) once the well is to be placed in a permanent or temporary abandonment.

* * * * *

■ 37. Amend § 250.1721 by revising paragraph (h) to read as follows:

§ 250.1721 If I temporarily abandon a well that I plan to re-enter, what must I do?

* * * * *

(h) Submit certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements of paragraph (b) of this section. In addition to the requirements of paragraph (b) of this section, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in § 250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM

(Form BSEE–0124) required by § 250.1712 of this part.

[FR Doc. 2012–20090 Filed 8–16–12; 4:15 pm]

BILLING CODE 4310–VH–P