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Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Oil and Gas Drilling Operations; Final Rule

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 250

RIN 1010–AC43

Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Oil and Gas Drilling Operations

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This final rule restructures the requirements for oil and gas drilling operations on the Outer Continental Shelf (OCS), adds some new requirements, and converts the regulations into plain language. The restructuring of the rule follows the logical sequence of obtaining approval to drill a well and conducting drilling operations. The final rule also removes overly prescriptive requirements and updates requirements to reflect changes in drilling technology. Restructuring the drilling requirements makes the regulations easier to read, understand, and follow. The technical changes will help ensure that lessees conduct operations in a safe manner.

EFFECTIVE DATE: The rule is effective March 24, 2003. The incorporation by reference of publications listed in the regulation is approved by the Director of the Federal Register as of March 24, 2003.

FOR FURTHER INFORMATION CONTACT: William Hauser, Engineering and Operations Division, at (703) 787–1613.

SUPPLEMENTARY INFORMATION: On June 21, 2000, we published a Notice of Proposed Rulemaking (65 FR 38453), titled ''Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Oil and Gas Drilling Operations'' to revise the subpart D regulations of part 250, with exception of the regulations on Hydrogen Sulfide under 30 CFR 250.417. The proposed rule had a 90-day comment period that we extended to 120 days on July 27, 2000 (65 FR 46126). The extended comment period closed on October 19, 2000.

Differences Between Proposed and Final Rules Not Directly Related to Comments

In addition to changes we made to the final rule in response to public comments, we reworded several sections to further clarify the requirements. We also changed several section titles to better reflect the intent of the sections. The following are the changes by section:

• Section 250.403—We divided the requirements contained in the table in this section into three new sections. We believe this change provides a better understanding of the requirements. The new sections are:

250.404 What are the requirements for the crown block?
250.405 What are the safety requirements for diesel engines on a drilling rig?
250.406 What additional safety measures must I take when I conduct drilling operations on a platform that has producing wells or has other hydrocarbon flow?

• New § 250.405—We added engines on escape capsules to the list of diesel engines that you do not have to equip with an air intake device. We believe that this device should not be required on an escape capsule. We also revised paragraph (b) by adding the term ''remote'' to manual air intake shutdown device so that the requirement means the same as the previous requirement. Paragraph (b) now reads as follows: ''For a diesel engine that is continuously manned, you may equip the engine with either an automatic or remote manual air intake shutdown device;''.

• New § 250.406(b)—This paragraph applies to shutting in producing wells during the movement of a drilling rig on and off a location. We clarified the requirements of this section in response to comments from the Offshore Operators Committee (OOC) (see discussion in OOC comments section). We want to further clarify in the preamble of this rule that the same requirements to shut in producing wells would apply when a lessee moves in a drilling rig or coiled tubing unit to complete or workover a well. We plan to clearly state these requirements for completion and workover activities in revisions of subparts E and F that we anticipate proposing.

• Sections 250.408 and 250.409—We added two new sections to address the use of alternative procedures or equipment during drilling operations and obtaining departures from the drilling regulations. We made this revision to clearly state the procedures for using alternative procedures or equipment and for obtaining departures from the drilling regulations. We also removed phrases similar to ''or as otherwise approved by the District Supervisor'' throughout the rule because you may request a departure or the use of alternative procedures or equipment with respect to any of the drilling requirements prescribed in the rule, provided the rationale is appropriate.

• Section 250.414—We added an introductory sentence to this section which states that the drilling prognosis must include a brief description of the procedures that you will follow in drilling the well. That description includes the nine items listed (a) through (i) in this section and any other events or procedures that are out of the ordinary for drilling activities. We also moved the paragraph on listing and describing departures or requests to use alternative procedures and equipment to this section.

• Section 250.421(d)—We revised this paragraph to read as follows: ''As a minimum, you must cement the annular space 500 feet above the casing shoe and 500 feet above each zone to be isolated.'' We inserted the phrase ''500 feet above'' before ''each zone'' to ensure that there was no confusion about cementing requirements for the intermediate casing. This clarification is consistent with the current regulations.

• Section 250.424—We converted the requirements for pressure testing casing into a table. This will make the requirements easier to understand.

• Section 250.427—We clarified the requirement for when you must conduct a pressure integrity test after drilling new hole below the casing shoe. The original requirement stated a maximum amount that you could drill before conducting the test (50 feet). The revised requirement has both a minimum (10 feet) and a maximum (50 feet) amount that you could drill before conducting the test. This will remove any confusion about how much new formation you must drill before conducting the test.

• Section 250.465(a)(3)—We revised this paragraph to require the submittal of a plat certified by a registered land surveyor when you determine the well's final surface location, water depth, and the rotary kelly bushing elevation. This requirement is consistent with the current regulations. The certified plat serves a useful purpose because it provides certainty to the well's location. In some instances, submittals of non-certified plats or reliance upon the planned location plat provide only a rough idea of where the well may be located.

Changes to Drilling and Well Forms Not Related to Comments

Through a separate process, MMS revised the associated 30 CFR 250, subpart D, drilling and well forms MMS–123, MMS–123S, MMS–124, MMS–125, and MMS–133. We are conducting the form revisions in compliance with the requirements of the Paperwork Reduction Act of 1995 (PRA), and as part of our efforts to implement the Government Paperwork

Elimination Act and streamline data collection. The revised forms were published for comment in the **Federal Register** on May 1, 2002 (67 FR 21718). In addition to revising some of the data elements on each form, we changed the titles of forms MMS–124 (Sundry Notices and Reports on Wells changed to Application for Permit to Modify), MMS–125 (Well Summary Report changed to End of Operations Report), and MMS–133 (Weekly Activity Report changed to Well Activity Report). In accordance with the PRA, we submitted the revised forms to the Office of Management and Budget (OMB) for approval. The OMB approved the use of the new forms in October 2002 and these final regulations incorporate the changes to the forms.

Comments on the Rule

We received 11 sets of comments on the proposed rule and other considerations for drilling regulations. The comments came from four oil and gas lessees/operators (Chevron USA Production Company, Shell Exploration & Production Company, Torch Operating Company, and Mariner Energy), two drilling contractors (Noble Drilling Services and Rowan Companies), three trade organizations (American Petroleum Institute (API), OOC, and International Association of Drilling Contractors (IADC), one consultant (West, Inc.), and one private citizen (James E. May). You may view these comments and the Notice of Proposed Rulemaking (NPR) on the MMS Web site at address: *http://www.mms.gov/federalregister/PublicComments/rulecomm.htm.* The OOC and IADC provided the most comprehensive sets of comments on the proposed rule. Three of the operators and both drilling contractors fully supported the comments of their respective trade organizations and provided additional comments. The API noted that it worked with OOC in preparing detailed comments on the rule and fully supports the comments submitted by OOC. The OOC presented its comments on specific sections of the rule in a table that identified the section, suggested changes, and provided rationale for those changes. We found this to be an informative format for reviewing comments and have used that format to respond to OOC's comments.

We organized our responses to comments on the NPR into three sections. These sections address the following topics:

I. General comments and comments on other considerations for drilling regulations (*i.e.*, need for regulations on the use of coiled tubing, mandatory use of automated pipe handling systems);

II. Comments on specific sections that OOC did not address in its comments; and

III. OOC's comments on specific sections (table format).

I. General Comments and Responses

• *Comment:* The use of Lessees/Operators/Contractors relates better to these regulations than the use of ''I'' and ''you.''

Response: We disagree. The use of ''I'' and'' ''you'' in the regulations essentially replaces the terms ''lessees, operators, and contractors.'' It is much easier to say ''you must'' versus the ''lessee/operator/contractor must.''

• *Comments on Incorporating API Recommended Practice (RP) 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells (API RP 53) into the regulations:* One commenter stated that the incorporation of specific sections of API RP 53 is appropriate because incorporation of the entire document would lack the specificity needed for the regulations. Another commenter recommended that the entire contents of API RP 53 should be incorporated by reference to provide overall guidelines for blowout preventer (BOP) systems.

Response: MMS has incorporated specific sections of API RP 53 into the regulations as proposed. The primary reason for selecting specific sections was to provide needed specificity to the existing requirements. However, API RP 53 provides excellent guidelines for operating and maintaining BOP systems, and MMS will consider incorporating the entire document in a future revision of the drilling regulations.

MMS will also consider the incorporation of other API drilling documents. MMS recently contracted with West, Inc. to review and compare three API Recommended Practices to MMS regulations and IADC's Deepwater Guidelines. The three Recommended Practices are:

1. 16E—Design of Control Systems for Drilling Well Control Equipment;

2. 64—Diverter System Equipment and Operations; and

3. 16Q—Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems.

West, Inc.'s complete report is available on the MMS Web site at *ftp://www.mms.gov/TARProjects/380/380AA.pdf.*

• *Comments on Automated Pipe Handling Systems:* This topic generated many comments, most of which disagreed with requiring automated pipe handling systems. Comments against requiring these systems included the following:

—Little data exist to support the theory that automated pipe handling systems measurably improve personnel safety;
—Automated pipe handling systems create new safety hazards (i.e., new pipe racking systems have introduced additional tripping hazards to rig floor personnel which have resulted in lost time incidents);
—Costs (including capital and out-of-service time) to retrofit the drilling units would not be justified considering the perceived safety benefits;
—Some drilling units could not be retrofitted due to space limitations and/or due to the added weight of the automated pipe handling equipment; and
—Reliability is an issue with some automated systems

Other comments questioned if automated systems meant totally automated pipe handling systems or just a subset of automated rig floor equipment such as iron roughnecks, spinners, and power slips. Commenters also asked if operations would have to be suspended if the automated systems were not available due to downtime. While the vast majority of the comments were against requiring automated systems, one comment said that MMS should require some automated rig floor equipment, but those requirements should be flexible and a practical application of existing technology.

Response: MMS appreciates the comments industry has provided on this topic, and we now have a better understanding of how a requirement for an automated pipe handling system could impact the drilling industry and drilling operations. One of the purposes for raising this issue in the preamble of the proposed rule was to elicit this information. This final rule does not include any requirements for automated pipe handling systems or automated rig floor equipment. Nor is MMS proceeding with any proposed regulations on these systems at this time.

• *Comments on Best Cementing Practices:* Most comments were along the lines that best cementing practices should be used where possible, but that specific practices should not be mandated by specific requirements. OOC stated that the complexity of cementing operations and a variety of cements are not good candidates for prescriptive requirements. One suggested approach was to supplement current cement compressive strength and height requirements with regulatory guidelines that would allow the needed flexibility to determine which practices are applicable to the particular down-hole environment. Several commenters noted that they are participating in an API/International Standards Organization (ISO) Cementing Committee to discuss best cementing practices with MMS and develop appropriate guidance for best cementing practices.

Response: MMS will continue with the cementing requirements as proposed in this rule. These requirements are similar to the requirements that were in the previous regulations. As noted in the above comment, MMS is participating in the API/ISO Cementing Committee and will work with the committee to develop appropriate guidelines for cementing practices. We may take further regulatory actions after the committee completes its work.

• *Comment:* One commenter said that the proposed regulations do not protect the environment enough, and that MMS is aware of a substantial number of OCS wells that are leaking oil to the surface and between formations. The commenter asserted that the proposed rule aggravates this problem by using the term ''cementing.'' The commenter asked why MMS allows oil companies to use cement and not other sealants.

Response: MMS believes that the proposed regulations for cementing wells provide adequate protection to the environment. MMS also believes that there are opportunities to improve cements and cementing practices so, over the years, MMS has participated in a number of research projects that examined ways to improve cementing in oil and gas wells. We continue to participate in cementing research efforts and other efforts, such as the API/ISO Cementing Committee, to ensure that cementing technology continues to advance. MMS requires industry to use cement to seal formations and plug wells because it works; however, we will allow industry to use other sealants if they provide equal or better performance than cement. In the past, these generic requests to expand the rules to allow the use of other ''sealants'' have sometimes actually been attempts to get approval to use clays, gels, and other low compressive strength, non-hardening compounds.

MMS knows of only a few abandoned wells that have leaked after permanent abandonment. When we become aware of an abandoned well that is leaking, we require the operator of record to take immediate action to remedy the situation. Also, to further our awareness of potential leaking abandoned wells, MMS has recently sponsored research to identify leaking abandoned wells by using remote sensing.

• *Comment on regulating coiled tubing drilling:* The OOC commented that MMS was taking the correct approach by not proposing specific regulations for coiled tubing drilling. OOC agreed that a better understanding of these operations and the amount of activity that is likely to take place on the OCS was necessary before drafting regulations. OOC stated that the existing/proposed provisions in subpart D, coupled with the District Supervisors' authority to approve alternative techniques and procedures, adequately addresses the regulatory mandates. OOC also supported the use of API RP 5C7 for Coiled Tubing Operations in Oil and Gas Well Services (API RP 5C7) as a guideline when preparing the appropriate regulations.

Response: MMS will continue to monitor the use of coil tubing on the OCS and will propose additional regulations as needed.

II. Comments on Specific Sections That the OOC Did Not Address in Its Comments

• *Comment on § 250.404 What mobile drilling unit movements must I report?* This requirement should be waived after commencement of the first well on a platform.

Response: We have revised this section to clearly state what rig movements the lessee must report to MMS. This includes the movement of both mobile offshore drilling units (MODU) and platform rigs. We need this information to ensure that our inspectors have the correct information in hand when they arrive at a platform rig to perform an inspection. MMS also needs to know the movement of drilling rigs, coiled tubing units, and snubbing units on and off locations for completion and workover activities, so we will clarify these requirements in revisions of 30 CFR 250, subparts E and F that we anticipate proposing.

• *Comment on § 250.404 What mobile drilling unit movements must I report?* The proposed rule duplicates U.S. Coast Guard (USCG) requirements to report MODU movements under 33 CFR parts 67 and 72. While the proposed rule affects the lessee, the MODU owner is reporting the required information to the USCG. MMS and USCG should share this information so that you can eliminate a reporting requirement.

Response: MMS needs MODU movement information 24 hours in advance of movement to plan our rig inspections. USCG's timing requirements for rig movement notice do not meet our rig inspection planning needs. Based on similar comments during the process to develop the new MMS form to report rig movements, we incorporated ''optional'' information needed by the USCG so that the form could be used for reporting to either agency.

• *Comment on § 250.412 What requirements must my plat meet?* The lessee or operator should be allowed to decide how to report well location.

Response: MMS must have the coordinates reported in a consistent manner to ensure that the exact well locations are known.

• *Comment on § 250.417 What information must I provide if I intend to use a mobile drilling unit to drill a proposed well?* Paragraph (c) may require a third-party review of a MODU's design by a Certified Verification Agent. This review may involve the MODU's structural components or integrity which would be in direct conflict with the December 1998 Memorandum of Understanding (MOU) between MMS and USCG. Under that MOU, the USCG has full responsibility for the structural integrity of MODUs.

Response: This is not a new requirement (see current regulation at § 250.401(a)(3)). The purpose of this requirement is to address the possible unique drilling unit that a lessee may propose to use in a frontier area. Our intent is to ensure that proper design reviews are conducted before the unit's use at a proposed frontier location. When this situation occurs, MMS will confer with the USCG concerning the drilling unit design and its use at the specified location. If the USCG design review meets our concerns, then MMS will not require additional design reviews. If additional reviews are needed, the District Supervisor will use this requirement to address necessary information. We have revised this paragraph to clarify that this requirement applies only to frontier areas where the drilling unit design is unique or the unit has not been proven for use in the proposed environment. MMS will follow the 1998 MMS/USCG MOU to the extent possible to minimize duplicating design requirements of both agencies.

• *Comments on § 250.417(h) and 250.418(a).* The IADC and two drilling contractors commented that these paragraphs indicate that MMS is maintaining files of rig-specific information. While such action by MMS is clearly in a drilling contractor's interest, they could not find the authority for MMS to maintain files on individual drilling rigs or to transfer this information between the files of lessees/ operators.

The commenters were frustrated that MMS interprets its legislative authority as precluding direct contact between the agency and rig owners. They are convinced that direct communication between MMS and MODU owners/ operators is permissible and advisable. They recommended that MMS should review and approve the use of MODUs and platform rigs on a regional basis. This would eliminate what appears to be a repetitive and non-productive review of identical drilling rig specifications by its District Offices.

Response: The lessee/operator must submit a detailed description of the drilling unit including specifications for all its components, regardless of whether it is a MODU, with the Application for Permit to Drill (APD) a new well. MMS may communicate with the contractor; however, it is the responsibility of the lessee/operator to submit the required information to MMS. Drilling unit documents are part of the APD and are maintained in well data files by MMS.

MMS does maintain limited files (work history, where and when built, depth capability and water depth, safe welding area approval, USCG certificate, etc.) on drilling rigs in the Gulf of Mexico (GOM). This information is useful as a cross reference of submitted information and when the lessee/ operator does not include rig-specific information with the APD or sundry notice. Such information is used only within MMS (although much is readily available on the company Web sites) and is not transferred between lessees/ operators. MMS only requires submission of this basic rig information and job-specific information such as BOP sketch, diverter sketch, and similar related information. This job-specific information can change due to rental BOPs and diverters or procedural changes.

MMS drilling and workover engineers, as well as inspectors, regularly talk with rig owners, superintendents, pushers, drillers, and operator personnel about rig conditions, pollution, new equipment, training, accidents, etc. Only those items specific to a location, items that must be renewed regularly (certificates), and training are reviewed for each APD or sundry notice, and even some of these are only checked by the inspector once work has started. It is up to the lessee/ operator via their contracts to require that rig owners conform to MMS regulations.

- *Comment on § 250.422(b) When may I resume drilling after cementing?* A commenter said that the waiting time before removing the diverter is not necessary.

Response: MMS disagrees. Determining the time when it is safe to remove the diverter is just as important as determining the time for the BOP because several incidents have involved early removal of the diverter.

- *Comment on § 250.423(f) How must I remedy cementing and casing problems and irregularities?* A commenter suggested that field-specific rules rather than general rules should apply to the requirement that you must have at least two cemented casing strings to produce a well.

Response: Field rules could apply if they are established in accordance with § 250.463.

- *Comment on § 250.424(b) What are the requirements for pressure testing casing?* The requirement should allow an exception for horizontal cementing applications.

Response: To obtain an exception for pressure testing casing, you may request approval from the District Supervisor to use alternative procedures (§ 250.408) or obtain a departure (§ 250.409). The District Supervisor will evaluate these requests on a case-by-case basis. Therefore, we did not include an exception for horizontal cementing applications in the requirements.

- *Comment on § 250.430 When must I install a diverter system?* MMS shouldn't require installation of a diverter when returns are taken at the ocean floor (*i.e.*, no casing/riser on which to install a diverter).

Response: The regulations require the installation of a diverter system before you drill a conductor or surface hole. If you want to drill a conductor or surface hole without a diverter, you must include this procedure in your APD and obtain approval from the District Supervisor.

- *Comment on § 250.431 What are the diverter design and installation requirements?* MMS should consider removing statements from the regulations that are not auditable, such as minimizing the number of turns or maximizing the radius of curvature of turns for diverter lines for bottom-founded drilling units. MMS could reference industry standards such as API RP 53 to better define what is required.

Response: MMS will continue with the current performance standards of minimizing the number of turns and maximizing the radius of curvature of turns for diverter lines. We used these standards in past regulations because it is difficult to prescribe measures that will work for each drilling unit. However, in future rulemakings, we will consider incorporating additional standards to address some of the requirements that are difficult to audit.

- *Comment on § 250.433 How must I test the diverter system after installation?* MMS should allow for testing diverters on a 14-day frequency.

Response: MMS conducted several studies on BOP performance before we revised the regulations to allow for testing BOPs on a 14-day frequency. We made sure that extended testing frequency would not compromise safety during drilling operations. MMS will not consider revising the testing frequency for diverters until research shows that an extended testing frequency will not compromise safety.

Comments on § 250.441 What are the requirements for a surface BOP stack?

This section proposed that each surface BOP stack must have at least one preventer equipped with blind-shear rams within 1 year after the effective date of this final rule. This proposed requirement prompted many comments. Four commenters opposed the proposed requirement and provided reasons for their opposition. IADC provided the most comprehensive comments against this proposed requirement. A fifth commenter stated that it also opposed the proposed requirement and said it supported IADC's comments. Three other commenters stated that they supported IADC's and OOC's comments but they did not specifically mention the proposed requirement for blind-shear rams. Two other commenters also provided comments on this proposed requirement and those comments are included below.

A summary of all the comments on the proposed requirements for blind-shear rams follows:

—IADC plotted the incidents over the 20-year period, and its graph showed that the incident rate where blind-shear rams might have prevented a serious blowout is approaching zero. IADC believes that this trend is sufficient to negate the need for MMS to mandate the installation of the blind-shear rams. Possible activities that lead to this declining trend include:

- Greater attention being paid to safety management as a result of Safety and Environmental Management Programs and other initiatives;
- Continuous improvement in well control methods and equipment; and
- Greater attention to the quality of well control training

—IADC also stated the following:

• Successful operation of blind-shear rams (intentional or not) permanently forecloses other well control options;

• MMS did not consider the consequences of inadvertent operation or malfunction of the rams;

• MMS underestimated the number of surface BOP stacks that would need blind-shear rams by 50 percent, thus underestimating the costs by 50 percent; and

• If the final rule requires the blind-shear rams, then industry will need an additional 2 years to comply with the requirement.

—Operating limits of blind-shear rams are frequently unclear for some drilling operations due to pipe grades, mud weights, and wellbore pressures, and that consideration should be given to ensure that these limits are clear

Response: MMS continues to believe that having blind-shear rams in a surface BOP stack is an important safety measure. Blind-shear rams offer an additional opportunity to control the well in a difficult situation. We believe that these rams provide the last line of defense against a blowout when drill pipe or tubing is hung in the BOP stack and there are difficulties in installing or closing the drill string safety valve, inside BOP, or tubing safety valve. Successful operation of the blind-shear rams may prevent damage to the drilling rig, platform, or other facilities, and prevent injuries or the loss of life.

The IADC and industry provided a number of comments on why MMS should not require blind-shear rams in surface BOP stacks. Their most compelling reason against requiring blind-shear rams is industry's recent performance concerning incidents where blind-shear rams might have prevented or minimized a blowout. Those comments are correct in that industry's recent performance is good, especially when compared to the relatively high number of incidents that occurred in the early 1980's. However, there have been three serious incidents where blind-shear rams may have prevented a blowout since 1996 (two incidents occurred in 2001). A brief description of each event follows:

Incident 1—occurred on Platform A, Eugene Island Block 380, on January 24, 1996. During completion operations, the well began to flow while the tubing was extended above the BOP stack. The crew tried to stab the top drive into the top of the tubing but the flow had increased and they were unable to make the connection. The driller closed the blind rams to reduce the flow but that did not help. Gas began to flow out of the top of the tubing, so the drilling crew closed the pipe rams and annular preventer and evacuated the rig floor. During the evacuation of the rig and platform, the well caught fire. The fire destroyed the rig substructure and derrick and severely damaged other parts of the rig. Fortunately there were no injuries or pollution. After investigating the accident, MMS' investigation team recommended that blind-shear rams should be required in surface BOP stacks. The investigation report can be found on our Web site at: *http://www.gomr.mms.gov/homepg/offshore/safety/acc_repo/98–0012.pdf*.

Incident 2—occurred on Platform A Eugene Island Block 277, on July 6, 2001. While killing a kick that occurred during workover operations, the pressure safety valve on the mud pump ruptured. The well then flowed uncontrolled through the drill pipe and the ruptured pressure safety valve. The area around the rig equipment and drill floor became inundated with a hazardous accumulation of gas and formation sand which forced all personnel to evacuate to a standby boat. Fortunately there were no injuries and only major damages to the rig. The investigation report can be found on our Web site at: *http://www.gomr.mms.gov/homepg/offshore/safety/acc_repo/2002-040.pdf*.

Incident 3—occurred on a jack-up drilling rig drilling in Brazos Block 417 on July 13, 2001. During drilling operations, the well began to flow while the crew was making up the next joint of drill pipe in the mouse hold. The rig floor safety valve was stabbed but would not close with two men applying torque to the handle. Both men were burned on their arms and back by the hot mud. Because of the high temperature of the mud, the men had to put on slicker suits and were sprayed with water to continue working on the rig floor. A third man assisted in the attempt to close the valve and sufficient torque was applied to the closing handle to shear it off at the key opening of the valve. Mud continued flowing out of the drill pipe until it was shooting over the the top of the derrick. Gas began to flow with the mud from the drill pipe and it became unsafe to work on the rig floor. The crew was ordered to abandon the rig. After the rig was abandoned, it was discovered that the night supervisor was missing. The Coast Guard searched for two days but the night supervisor was never found. The BOP stack, casing and drill pipe were damaged by high pressure gas and sand that flowed from the well. The rig was also damaged by the gas and sand flow. The investigation report can be found on our Web site at: *http://www.gomr.mms.gov/homepg/offshore/safety/acc_repo/2002-062.pdf*.

In these incidents, the drilling crews had run out of options to control the well and were forced to abandon the rig. We believe that the injuries, the fatality, and rig damages could have been avoided if blind-shear rams were in the BOP stack and were closed prior to evacuating the rig. Similar incidents have occurred during drilling, workover, and completion operations in the past, and blind-shear rams stopped the blowout. Similar incidents are very likely to occur in the future.

In the preamble of the proposed rule, MMS stated that it had reviewed the blowouts that have occurred since 1977 and found at least 12 incidents where blind-shear rams had helped or could have helped control the situation. Upon closer review of our records, we have identified 24 incidents where blind-shear rams either helped control a blowout or may have helped prevent a blowout (these records include MMS's database, memoranda, accident reports, investigations, operator letters, and operator investigations). The table below gives the date, location, and a brief description of each of those incidents. There were 10 fatalities, 23 injuries, 3 rigs destroyed, and 9 rigs damaged during those incidents. Furthermore, six of the investigation reports recommended that blind-shear rams be installed in surface BOP stacks. Considering that the installation of blind-shear rams provides an additional means of controlling a blowout and can help prevent future injuries, fatalities, and protect property and the environment, MMS will require the installation of blind-shear rams in surface BOP stacks.

Date	Block/lease #	Description of incident
6/23/77	Eugene Island 307, G 2110	Blowout while running dual completion string. Tubing was 84 feet above the drill floor when well began blowing through the tubing. The tubing safety valve could not be installed so blind rams were closed but only crimped the tubing. Crew evacuated the rig safely. The blowout was controlled later that day. The Investigation Report recommended that the U.S. Geological Survey require shear rams on all BOP stacks.

Date	Block/lease #	Description of incident
7/20/77	West Cameron 110, OCS 081	Blowout occurred during workover operations. Well began to flow while pulling out of the hole. Drill string safety valve was installed but could not be closed. Blind rams were closed to restrict the flow but had no effect. There were no injuries. Well Control Team secured well 4 days later.
11/26/77	Eugene Is. 307 G, 2110	Well blew out while running into the hole during completion operations. All of the BOP's were closed but the well continued to flow. The flow was too great to stab the drill string safety valve. After 6 hours of attempting to diminish the flow through the drill pipe, the crew was able to install and close the drill string safety valve.
8/4/78	Grand Isle 41, G 0129	Blowout occurred during completion operations. Drill string safety valve could not be closed after well began to flow. After 15 minutes, the driller regained control of the well by closing blind-shear rams. There were no injuries.
3/5/79	S. Marsh Island 281, G 2600	While attempting to correct lost returns and stuck pipe problems, the well began to flow. The crew could not close the drill string safety valve when the well kicked the final time. There were eight fatalities and considerable damage to rig. The USCG Investigation Report (Oil & Gas Journal, p. 148, Nov. 17, 1980) concluded that shear rams could prevent similar casualties in the future.
8/24/80	Vermilion 348, G 2271	The well kicked while making up gravel pack assembly. The blind and pipe rams were closed on 4½″ pipe portion of gravel pack assembly but did not seal the well. The drilling rig and portion of platform were destroyed. There were four minor injuries in the crew evacuation. The well bridged 37 days later.
1/12/81	High Island 38, G 0477	Blowout occurred while circulating out a kick. The well blew out through the neck on the swivel. The lower kelly cock was left 12 feet above the drill floor and was not closed. The blowout lasted approximately 12 hours, catching fire towards the end of the incident. Three people suffered overexposure after the evacuation and one later died.
7/26/81	South Pelto 18, G3589	Blowout during completion operations. While circulating mud, the well kicked. Crew closed upper kelly cock but it leaked. Operator closed blind-shear rams and evacuated platform. Gas leaked through the blind-shear rams but the rig never caught fire. Well was controlled 4 days later. One person suffered a broken leg and bruises during the evacuation.
10/5/81	Eugene Island 273, G 0987	Blowout occurred when the tubing parted during completion operations. The well was controlled after 38.5 hours by installing and closing blind-shear rams. The Investigation Report recommended that BOP stacks have blind-shear rams for completion operations. There were no injuries during the evacuation.
11/28/81	Viosca Knoll 900, G 2445	Blowout occurred during workover operations. The well kicked while pulling out of the hole. The BOPs were closed, but the flow through the drill string was too great to stab the drill string safety valve. The blowout lasted 24 hours. There was some pollution but no injuries and minimal damages.
4/19/82	Galveston 391, G 3740	Blowout occurred while completing the well. A drill string safety valve could not be installed because the drill pipe was above the monkey board. Well bridged over in 3 hours. There were no injuries and only minimal damage to the platform and rig.
5/15/82	S. Marsh Island 155, G 4110	While circulating a kick, an explosion and fire occurred under the rig floor and at the shale shaker. Blind-shear rams were activated and the well was shut in. Three people suffered minor injuries during the evacuation.
7/14/82	West Cameron 65, G 2825	Fishing operation when well began to kick. While attempting to control kick, the stand pipe blew out and the drilling crew could not close either of the kelly valves. Jackup rig was destroyed and the blowout continued for 57 days. There were no injuries.
12/17/82	West Delta 70, G 0182	Blowout occurred while working over well with a snubbing unit. Blowout pushed top of workstring to a point 30 feet above the highest object on the platform. Blowout was stopped after repeated attempts to function the shear rams.
10/20/83	Eugene Island 10, G 2892	While controlling a kick during a workover, gas began to leak from the threads in the crossover sub and the drill string safety valve. The leak increased as the valve was closed, forcing the abandonment of the rig. The well was killed 6 days later. There was major damage to the rig but no injuries.
12/3/85	West Cameron 648, G 4268	Blowout during workover. Crew unable to stab workstring safety valve into the workstring when fluid began flowing. Three people were injured trying to stab the safety valve. The rig was destroyed and the platform heavily damaged by fire. The blowout lasted 47 days. The Investigation Report recommended that Order 6 be revised to require blind-shear rams in BOP stack during workovers.
3/20/87	Vermilion 226, G 5195	Blowout during completion activities. Blowout through the drill pipe and drill string safety valve failed. The well control team killed the well by installing blind-shear rams and shutting in the well. There were no injuries and only minor damage during the 3-day blowout. The Accident Investigation Report recommended the installation of blind-shear rams in BOP stacks.
5/30/90	Brazos A–23, G 3938	Blowout occurred during testing operations. The blind-shear rams were closed but failed as the rig was being jacked up to clear tubing from the blind rams. Blind rams were closed but gas flowed until well control team killed the well. There were no injuries and only minor damages during the 2-day blowout.
9/9/90	Eugene Island 296, G 2105	During workover operations, well began to flow through tubing after running one stand of collars and one stand of tubing into the well. Crew made at least four unsuccessful attempts to install full opening safety valve. The BOPs were closed but did not stop the blowout. There were eight injuries and rig damage during the 4-day blowout.

Date	Block/lease #	Description of incident
1/24/96	Eugene Island 380, G 2327	During completion operations, the well began to flow while the tubing was extended above the BOP stack. Crew tried to stab the top drive into the top of the tubing but the flow prevented the connection. The driller closed the blind rams to reduce the flow but that did not help. When gas began to flow out of the top of the tubing, the drilling crew closed the pipe rams and annular preventer and evacuated the rig. During the evacuation of the rig and platform, the well caught fire. Fire destroyed the rig substructure and derrick and severely damaged other parts of the rig. MMS investigation report recommended that blind-shear rams be required in surface BOP stacks. (incident 1 in above discussion).
5/31/97	East Cameron 83, G 8641	Blowout during completion operations. Well control team replaced pipe rams with blind-shear rams but found that the tool joint was opposite the rams. There were no injuries, pollution, or fire. Well was out of control for 19 days.
12/2/99	SM58, G 01194	Blowout occurred while running a gravel pack assembly during completion activities. The gravel pack was across the BOP stack when the well began to flow. The BOP's were closed but did not stop the blowout. The well bridged over the next day.
7/6/01	Eugene Island 277, OCS–G 10744.	Blowout occurred during a workover operation. Well flowed uncontrolled through the drill pipe and ruptured pressure safety valve on the mud pump. The area around the rig equipment and drill floor became inundated with a hazardous accumulation of gas and formation sand thus forcing all personnel to evacuate to a standby boat. There were no injuries and only minor damages to the rig. (incident 2 in above discussion).
7/13/01	Brazos 417, OCS–G 22190	Blowout occurred during drilling operations. The well kicked and flowed up the drill pipe. The rig floor safety valve was stabbed but would not close with two men applying torque to the handle. Both men were burned on their arms and back by the hot mud. Because of the high temperature of the mud, the men had to put on slicker suits and were sprayed with water to continue working on the rig floor. The crew was ordered to abandon the rig. After the rig was abandoned, it was discovered that the night supervisor was missing. The Coast Guard searched for two days but the person was never found. The BOP stack, casing and drill pipe were damaged by high pressure gas and sand that flowed from the well. The rig was also damaged by the gas and sand flow. (incident 3 in above discussion).

IADC commented that we underestimated the number of blind-shear rams by approximately 50 percent (80), thus underestimating the costs by 50 percent. We have reexamined the number of rams that industry would have to purchase and found that of the rigs currently active or ready to work, 100 surface BOP stacks did not have blind-shear rams. When rigs temporarily taken out of service are included, 170 sets of blind-shear rams would be needed. Part of our low estimate was due to the increased drilling activity since we prepared the proposed rule and part was due to a low estimate of the number of blind-shear rams already installed in surface BOP stacks. Our recent review found that at least 30 sets of blind-shear rams are currently installed in surface BOP stacks.

MMS made two assumptions when estimating the cost of upgrading existing surface BOP stacks to include blind-shear rams. First, it was projected that all rigs active or ready to work would remain in service for more than the next 3 years. Second, one-half of the rigs temporarily taken out of service would be placed back into long term service over the next 3 years. Increasing the number of blind-shear rams needed to comply with this requirement to 135 sets will raise costs estimated in the proposed rule from $14,000,000 to $14,175,000. The original cost per set of blind-shear rams was overstated ($175,000), and has been reduced ($105,000) according to information obtained recently from BOP manufacturers. Given the number of rams that industry will have to purchase, MMS has allowed a 3-year timeframe for installing the rams versus the 1-year timeframe identified in the proposed rule. This 3-year period will allow industry sufficient time to plan the acquisition and installation of this critical safety equipment. The following table summarizes the costs associated with this requirement.

Requirement	Total cost	Annual costs	Cost to small businesses
Proposed Rule—Install blind-shear rams within 1 year	$14,000,000	$14,000,000 over 1 year	$0
Final Rule—Install blind-shear rams within 3 years	14,175,000	4,725,000 over 3 years	0

Avoidance of future blowout related costs, through the installation of blind-shear rams on all existing drilling rigs with surface BOP stacks, would constitute the potential benefits to lessees and their drilling contractors. In the analysis conducted for this rule, gross benefits are partially offset by the costs to purchase and install blind-shear rams, in surface BOP stacks that don't already have them. Our analysis indicates that implementation of the regulation will most likely result in net present value benefits to lessees and drilling contractors of $22 million. These benefits can be achieved by investing in the acquisition and installation of blind-shear rams for a present value cost of $13 million. Accordingly, the present value of gross industry benefits from this regulation will most likely be $35 million.

As discussed in the proposed rule, we believe that the final rule will not have a significant impact on small drilling contractors. It won't impact small drilling contractors because there is only one that qualifies as a small business, and that contractor has already equipped its surface BOP stacks with blind-shear rams. The drilling contractor indicated that the blind-shear rams were installed as an additional safety precaution.

IADC also commented that MMS did not consider the consequences of the inadvertent operation or malfunction of the blind-shear rams in the proposed rule. We know industry has many years of experience with having blind-shear rams in subsea BOP stacks and that industry has developed safeguards and procedures to prevent the inadvertent operation of this equipment. Also, several operators have many years of experience of having blind-shear rams in surface BOP stacks in the GOM. MMS, therefore, is confident that industry can adequately safeguard the BOP control panels and adequately train its personnel to prevent the inadvertent operation of blind-shear rams.

MMS disagrees with IADC's comment that the successful operation of blind-shear rams permanently forecloses other well control options. Many wells have been controlled after blind-shear rams shut them in. At least four of the wells identified in the table above regained control of the well by lubricating heavyweight drilling fluids into the annulus to kill the well (8/4/78; 10/5/81; 5/15/82; 3/20/87). While lubricating or bullheading fluids into a live well may not be the preferred method for regaining control of a well, it is better than losing total control of the well.

Finally, one commenter indicated that the operating limits of blind-shear rams are frequently unclear for some drilling operations due to pipe grades, mud weights, and wellbore pressures, and that consideration should be given to ensure that these limits are clear. We agree that this is important, so we have added a paragraph to § 250.416(e) that requires the lessee to address these issues. The new paragraph requires the lessee to provide information that shows that the blind-shear or shear rams installed in the BOP stack (both surface and subsea stacks) are capable of shearing the drill pipe in the hole under maximum anticipated surface pressures.

• *Comment on § 250.441 What are the requirements for a surface BOP stack?* MMS should revise the rule to allow an exception for less than four remote-controlled BOPs.

Response: Because you may include this request in your APD submission to the District Supervisor, we did not revise the rule to allow the use of less than four remote-controlled BOPs in certain situations.

• *Comment on § 250.442 What are the requirements for a subsea BOP stack?* One commenter asked why didn't MMS identify the costs associated with the subsea accumulator requirements.

Response: MMS did not specify any costs for this requirement because lessees/operators were already required by the regulations to have an accumulator that provided for fast closure. API RP 53 now provides guidelines for determining the minimum requirements and performance for the subsea accumulator.

• *Comment on § 250.442 What are the requirements for a subsea BOP stack?* A commenter noted that section 13.3 of API RP 53 does not include subsea accumulator volume requirements that can be audited other than the specific response times.

Response: MMS will review BOP test records, including documentation of the closing times of ram and annular preventers, in evaluating BOP system performance.

• *Comment on § 250.443 What associated BOP systems and related equipment must my BOP system include?* MMS should clarify that this section applies to both surface and subsea BOP equipment. The commenter also recommended that MMS consider adopting more sections of API RP 53 and/or API RP 16E instead of having a number of the specific requirements stated in the BOP system sections (250.440 to 250.451). Adoption of these documents would provide a more rigorous standard than the current MMS requirements.

Response: We clarified the intent of this section by revising the title to read ''What associated BOP systems and related equipment must my surface and subsurface BOP systems include?'' MMS will consider incorporating additional sections of API RP 53 and API RP 16E or possibly the entire document in possible future revisions of the drilling regulations.

• *Comment on § 250.446 What must I do to maintain and inspect my BOP?* MMS should consider incorporating parts of other quality management standards into the regulations, such as API Q1's, ''The supplier shall establish and maintain documented procedures for implementing corrective and preventive action * * * and API Spec 16A's, Appendix G, ''The operator of drill through equipment manufactured to this specification shall provide a written report to the equipment manufacturer of any malfunction or failure which occurs * * *''

Response: The quality management program incorporated by sections 17.12 and 18.12 in API RP 53 pertains to a planned maintenance system for BOP equipment and to maintaining copies of equipment manufacturer's product alerts and bulletins. The purpose for incorporating these sections was to ensure that BOP equipment is maintained properly. It was not to require equipment specifications or certification requirements for BOP equipment. MMS believes that incorporation of the specific sections of API RP 53 will meet the objective of identifying appropriate maintenance requirements.

• *Comment on § 250.448 What are the BOP pressure tests requirements?* MMS requirements for a low-pressure test provide a lower acceptance standard when compared to sections 17.3.2 and 18.3.2. MMS should consider incorporating these sections into the regulations.

Response: These sections of API RP 53 state the following on low-pressure tests: ''When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may continue to seal after the pressure is lowered and, therefore, misrepresenting a low pressure condition.'' MMS recognizes that this situation could occur on a low-pressure test, but we also recognize that it may be difficult to precisely apply 200 to 300 pounds per square inch (psi) to the component to be tested. Based on our experience and judgment, we have allowed operators to conduct a low-pressure test (200 to 300 psi) if the initial pressurization did not exceed 500 psi. Any pressure higher than 500 psi must be bled to zero and the test reinitiated.

• *Comment on § 250.448 What are the BOP pressure tests requirements?* MMS should consider testing ram preventers at an intermediate pressure, which ranges between 2,000 and 4,500 psi depending on closing ratio, because it provides a better measure of fitness for purpose. This intermediate pressure is another possible mode of failure. These intermediate pressure tests would be conducted initially and on an annual basis.

Response: MMS is unlikely to require such a test until it becomes an accepted industry practice.

• *Comment on § 250.449 What additional BOP testing requirements must I comply with?* The requirement for variable bore rams (VBRs) to pressure test against all sizes of pipe may be more rigorous than the largest and smallest sizes as recommended by API RP 53 (sections 17.5.5 and 18.5.5).

Response: We have revised the requirement in § 250.449(f) to now require you to pressure test VBRs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools. This conforms to API RP 53 recommended practice. Also, one of the findings from a 1999 research project, ''Reliability of Subsea BOP Systems for Deepwater Application, Phase II DW, by Per Holand of SINTEF Industrial Management,'' recommended that we should not require testing VBRs on all sizes. The rationale was that the testing of VBRs on all sizes adds very little to increased safety availability in the BOP due to the redundancy in the stack, and that most failures will occur during the pressure test.

• *Comment on § 250.449 What additional BOP testing requirements must I comply with?* Mandatory pressure testing of the BOP system after landing is not justified considering the extremely low failure rate of BOP components and the fact that the physical act of running the stack imposes little to no stress on the functional components of the BOP system. After a successful stump test, MMS should require only a function test for the BOP stack once it is on bottom. Function testing after landing will ensure that all control circuits are operating properly. This minor revision has a potentially huge beneficial impact by saving lost rig time to the initial BOP pressure test.

Response: We did not revise this requirement as suggested. We believe that the initial pressure test of the BOP stack after landing on the well is critical to ensuring that it functions properly. The results from our 1999 research project on the reliability of deep water subsea BOP systems (Holand, 1999) support our belief. That research project examined data from 83 wells that were drilled using subsea BOP stacks in the deep water GOM. The majority of the wells were spudded during July 1, 1997, to May 1, 1998. The results showed that 15 components failed during the initial pressure tests after the BOP stack landed on the wellhead. Of those 15 failures, 10 were in the control systems and may have been discovered in a function test. However, five other failures occurred (two connectors, one annular preventer, one ram preventer, one choke and kill valve) that may not have been discovered without the initial pressure test. MMS will continue to require the initial pressure test after landing the subsea BOP stack.

• *Comment on § 250.456 What are the required safe drilling fluid program practices?* Paragraph (a) should not require circulating the well before starting out of the hole if you have lost circulation.

Response: MMS believes that pipe should not be pulled out of the hole until a loss circulation pill has been spotted and the well is under control. It is recommended that the top part of the hole be circulated to ensure that the wellbore is clear of gas. Some loss of returns is acceptable while pulling out of the hole; however, excessive loss circulation would require remaining on bottom until the loss was controlled either with a pill or cement.

• *Comment on § 250.456 What are the required safe drilling fluid program practices?* Recommend that MMS eliminate the second sentence in paragraph (e) which says ''You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom.'' The first sentence of this requirement which says you must take appropriate measures to control the well is sufficient to address this situation.

Response: We did not remove the second sentence of this paragraph because this is a safe drilling practice. However, the sentence in question does allow for not running drill pipe to bottom to circulate the well if conditions prevent it.

• *Comment on § 250.456 What are the required safe drilling fluid program practices?* Recommend that paragraph (f) allow the District Supervisor the discretion to not require the posting of the surface pressure at which the shoe would break down.

Response: We did not revise this paragraph. You may request a departure from this requirement in your APD submission to the District Supervisor.

• *Comment on § 250.456 What are the required safe drilling fluid program practices?* MMS should allow the District Supervisor the discretion to not require degassers in all situations (paragraph (g)).

Response: We did not revise this paragraph. You may request a departure from this requirement in your APD submission to the District Supervisor.

• *Comment on § 250.458 What quantities of drilling fluids are required?* The commenter prefers the current wording over the proposed wording.

Response: The new regulations use a more active style of writing versus the passive style used in the previous regulations. The requirements (and most of the words) are the same.

• *Comments on § 250.459 What are the safety requirements for drilling-fluid-handling areas?* The two drilling contractors and IADC commented that the requirement to classify drilling-fluid-handling areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, is in conflict with the 1998 MMS/USCG MOU as it relates to MODUs. The MOU assigns regulatory oversight of this subject matter to the USCG. USCG regulations at 46 CFR 108.170 and 108.187 clearly address these matters, as do the Classification Society requirements applicable to MODUs. Accordingly, the requirements in this section should not apply to MODUs.

Response: This is not a new requirement. The USCG is responsible for the inspection on this area for electrical requirements; it is classified due to a possible source for gas coming out of the cuttings. MMS inspects for gas detectors and tests them on a regular basis. If we see anything that does not meet the USCG's requirement, such as an exposed wire, then MMS would shut down operation and require that it be repaired. All drilling-fluid-handling areas are treated the same.

• *Comment on § 250.460 What are the requirements for well testing?* These requirements should not apply if a well test is conducted on a permanent production facility.

Response: Your projected plans for a well test on a permanent production facility must address all appropriate requirements. You may reference another document or plan if it addresses a specific requirement, such as the description of safety equipment.

• *Comment on § 250.465 When must I submit sundry notices to MMS?* An open hole sidetrack to go around junk in the hole and to continue drilling to the original approved APD should not require a sundry notice.

Response: All sidetracks require the submittal of a sundry notice, and the API number is incremented. This allows the logs to be tracked and handled correctly.

III. OOC Comments on Specific Sections

The following table contains the OOC's unedited comments on the proposed requirements for oil and gas drilling operations and our response to those comments. In this table, we have italicized words that OOC wanted added to the regulations and have bracketed words that the OOC wanted deleted from the regulations.

Proposed section	OOC comments	OOC rationale	MMS response
250.198	Incorporate correct editions of API RP 500 and API RP 505 into the regulations.	By FEDERAL REGISTER Notice dated January 4, 2000, MMS incorporated by reference API RP 500, Second Edition and API RP 505, First Edition. Proposed Rule should be modified to state such.	The final rule references the correct documents and editions.
250.401(b)	(b) Have a person onsite *24 hours per day during operations* that represents your interests and can fulfill your responsibilities.	Include 24 hours a day to provide clarity.	We did not add the 24 hours per day because it is unnecessary, but we did add during operations as suggested.
250.401(c)	(c) Ensure that the toolpusher or a member of the drilling crew maintains continuous surveillance of the rig floor from the beginning of drilling operations until the well is abandoned *or completed*, unless you have secured the well with blowout preventers (BOPs), *bridge plugs, cement plugs,* or packers.	Well may go from drilling to completion and not be abandoned. Additionally, bridge plugs and cement plugs are viable options for securing the well.	We made the suggested changes.
250.402	When and how must I secure a well? Whenever you interrupt *drilling* operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the the device [as deep as possible] *at an appropriate depth* within a properly cemented casing string *or liner*.	The use of the phrase "as deep as possible" infers that the device should be set at the bottom of the hole. By changing "as deep as possible" to "an appropriate depth" allows the operator flexibility to choose appropriate setting depths.	We made the suggested changes.
250.402(a)	(a) [Among] The events that may cause you to [interrupt] *temporarily suspend drilling operations or*.	The proposed text regarding what types of events require securing of well downhole is vague and open-ended. Therefore, we recommend the word "among" in paragraph (a) be deleted, and the remainder of the paragraph be amended as recommended to detail the specific type of events, which is consistent with existing requirements.	We did not make the suggested change because there may be other events that cause you to interrupt drilling operations. The wording as suggested would limit the events that would require the installation of a downhole safety device.
250.403(c)	Requested clarity for paragraph (c) When you move a drilling rig or related equipment on a platform. You must shut in each well below the surface and at the wellhead, unless otherwise approved by the District Supervisor.	The language proposed is very vague. It appears that a subsurface shut-in is only required to move a rig while located on a platform (*i.e.* from well to well) and does not address rigging-up and rigging-down. Also applicability to MODUs is unclear (movement of cantilever jack-ups and floaters).	We revised the wording to clearly state when you must shut in each well below the surface and at the wellhead. The final wording is contained in § 250.406.
250.410(b)(3)	Form MMS–123S may require modifications to include additional information requirements. OOC requests that it be allowed to review and provide comments to the MMS, if the form is modified.	We assume that Form MMS–123S will be modified to contain new information requirements. Therefore, we believe it would be beneficial to both industry and the MMS to allow OOC to review the new form.	As previously discussed, MMS revised this form and the other subpart D drilling and well forms through a separate process. We provided an opportunity to comment on the revised forms and note that OOC did comment.
250.413(h)	(h) delete	We recommend that Line (h) be deleted. It is not clear how is this additional summary is to be submitted. (*i.e.* Is it to be included in Form MMS 123S or is it a narrative summary to part of the ADP, or is it a separate submittal?) The language as proposed is unclear, and OOC is not sure of the intent, or the purpose of this additional reporting requirement. Additionally, the summary report of the shallow hazards site survey will have been previously submitted with the EP/DOCD under which the well will be drilled.	The revised paragraph (h) now says that your well drilling design criteria must include a summary report of the shallow hazards site survey if it was not previously submitted.

Proposed section	OOC comments	OOC rationale	MMS response
250.414 (a), (b), (d), (e), (f) and (g).	Clarity is requested for lines (a), (b), (d), (e), (f) and (g)—What items must my drilling prognosis include? (a) Projected plans for coring at specified depths; (b) Projected plans for logging; (d) Estimated depths to the top of significant marker formations; (e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids; (f) Estimated depths to *major* faults; and (g) Estimated depths of permafrost, if applicable.	Currently the majority this of data is captured in the APD Information Spreadsheet. However, will the proposed form MMS–123S include other required data, such as estimated depths to the top of significant marker formations, major faults, etc? OOC assumes that the intent of the requirement is to identify faults that can potentially lead to problems while drilling. Therefore, it is recommended that the language be modified to include major faults only.	With the exception of providing the estimated depths to faults, these requirements were contained in § 250.415(f)(5) of the current regulations. You may use form MMS–123S to provide as much of this information as appropriate. Information you do not include on that form must be included with the drilling prognosis. As for estimating the depths to faults, we made the suggested change to require only the estimated depths to major faults.
250.415(a)	Hole sizes and casing sizes, including: weights; grades; [tension] collapse, and burst values; types of connection; and setting depths (measured and TVD).	The requirement for including the tension value has been deleted from the proposed language. This information has not been required in the past. The need to now require this information is unclear. If this requirement remains, will the ADP Information Spreadsheet/form MMS–123S, be revised to capture these values?	We made this suggested change. We will continue to require the tension casing design safety factor which is covered in paragraph (b).
250.417(a)	(a) If sufficient environmental information and data are not available, the District Supervisor may require you to collect and report this information *during the period of operation. The information to be collected and reported will be related to the structural integrity of the drilling unit and the safe conduct of operations*.	Clarity. The proposed language is too broad and does not present under which conditions the additional data would be required.	We added the phrase ''during operations'' to the requirement as suggested. We did not add the second sentence because it is unnecessary. The context of the section sets the limits for the type of information to be collected.
250.417(b)	(b) The District Supervisor may require you to conduct additional surveys and soil borings before approving the APD, *if the District Supervisor cannot make a determination that the proposed drilling unit can be supported at the specific site*.	Clarity. The proposed language is too broad and does not present under which conditions the additional data would be required.	The sentence was revised as follows: The District Supervisor may require you to conduct additional surveys and soil borings before approving the APD if additional information is needed to make a determination that the conditions are capable of supporting the drilling unit.
250.420(b)(1)	(b) Casing Requirements. (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects[; and combinations thereof].	OOC recommends that the phrase ''and combinations thereof'' be deleted because this statement is vague as to what combinations must be considered.	We did not make the suggested change. This is not a new requirement (currently in § 250.404(a)(3)). You must design casing to withstand all combinations.
250.420(b)(2)	(2) The casing design must include safety measures that ensure well control during drilling [and safe operations during the life of the well].	OOC recommends that the phrase ''and safe operations during the life of the well'' be deleted because it is too broad.	We did not make the suggested change. You must design your casing for the life of the well.
250.421(b)	(b) Use enough cement to fill the annular space back to the mud line. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill back to the mud line. *Excess cement may be washed out from the annulus below the mud line to a sufficient depth as necessary to facilitate well abandonment operations.* For drilling * * *.	Cement in the annular area between the conductor and the drive/structural pipe can cause difficulty in cutting pipe and clearing the location below the mud line.	We did not make this suggested change. Washing out or displacing cement is covered by § 250.418(g). That paragraph now says that washing out cement must be addressed in the APD.

Proposed section	OOC comments	OOC rationale	MMS response
250.421(f)	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate or production casing, you must set the top of the liner at least 100 feet above the previous casing shoe, *unless otherwise approved by the District Supervisor*.	It is common practice to achieve the liner-lap lengths discussed herein. However, there are instances when this is undesirable and, in those cases, a liner top packer is typically installed to ensure a good seal. The recommended language change will provide the District Supervisor the flexibility to approve a shorter liner-lap.	We did not make the suggested change of adding ''unless otherwise approved by the District Supervisor.'' In fact, we have removed that phrase from many sections because it is unnecessary. The District Supervisor has the flexibility to approve many requests without that phrase in the regulations. To emphasize this flexibility, we have added to the drilling regulations two sections: § 250.408, ''May I use alternative procedures or equipment during drilling operations?'', and § 250.409, ''May I obtain departures from these drilling requirements?''
250.421(f)	* * * If you use a liner as an intermediate or production casing, you must set the top of the liner at least 100 feet above the previous casing shoe.	Existing regulations include language that prohibits the use of a production liner when landed in a surface casing. Is this no longer the case?.	We have revised this paragraph to read ''If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe.'' MMS does not allow production liner to be set inside the surface casing, thereby to be used for production except in very limited conditions. Each such liner set departure must be individually reviewed.
250.422(b)	When may I resume drilling after cementing? * * * (b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, [in advance] when it will be safe to conduct this activity. Your determination must be *based on a knowledge of formations conditions encountered, presence of potential drilling hazards, actual well conditions while drilling, cementing and post cementing as well as past experience*.	The term ''in advance'' in the proposed text is very vague. We recommend it be removed and the actual information necessary to make the determination be stated. However, we do agree that the performance-based language as written in § 250.422(b) is appropriate. That is, making the operator responsible for assessing when it is safe to nipple down well control equipment. As a prudent operator, this assessment is made based on a knowledge of formations conditions encountered, presence of potential drilling hazards, actual well conditions while drilling, cementing and post cementing as well as past experience.	We made the following changes to this requirement: We replaced the phrase ''in advance'' with ''before nippling down'' because we wanted to ensure that no one made the determination after nippling down. We revised the last sentence of the requirement to include most of the wording suggested.
250.423(b)	(b) Change casing setting depths more than 100 feet *TVD* from the approved APD.	It is recommended that approval be obtained if the casing depth change is more than 100 feet TVD, not measured depth. Additionally, if the casing becomes stuck while running or other hole conditions prevent the running of casing to the projected setting depth, the operator should be allowed to cement the casing without seeking approval, and notify the District Supervisor subsequently.	We changed this paragraph to allow an increase of casing setting depth of up to 100 feet total vertical depth before requiring a submittal to the District Supervisor. In the case where the casing setting depth fell short of the planned depth, you would have to contact the District Supervisor only if the well conditions warranted revising your casing design (see § 250.423(a)).
250.423(h)	Submit geologic data and information to the District Supervisor that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging, [and] drilling fluid-monitoring *and other available geologic data* from wells previously drilled [within 500 feet] *in the immediate vicinity* of the proposed well path down to the next casing point.	The 500-foot limit is too prescriptive. This waiver should be based on the geologic data from an applicable analogous well.	We did not make the suggested change. The 500-foot distance was selected by MMS geologists and drilling engineers as a reasonable distance. MMS can best serve the industry by keeping the 500-foot distance in the regulations (see § 250.428(g)).

Proposed section	OOC comments	OOC rationale	MMS response
250.424(a)	(a) You must pressure test each string of casing to 70 percent of its minimum internal yield *or as otherwise approved by the District Supervisor.* This testing requirement does not apply to drive or structural casing. When a diverter is installed on conductor casing, you must test the casing to a minimum of 200 psi. [The District Supervisor may approve or require other casing test pressures.]	There is more than one currently approved method for calculating casing test pressure. We recommend that the alternative test methods be included in the new requirements, or allow the District Supervisor the discretion to approve alternative methods.	We chose not to list the alternative methods for calculating casing test pressure. You should address alternative test pressures or methods in your APD (see § 250.423).
250.431(a)	(a) Use diverter spool outlets and diverter lines that have [an internal diameter] *a nominal diameter* of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations.	API line pipe is normally used for diverter lines. Line pipe is different than casing. The nominal size of line pipe normally refers to the OD (for larger sizes).	We made the suggested changes.
250.434	(f) After drilling is completed, [retain all the records listed in this section for 2 years at the facility, at the lessee's field office nearest to the facility, or at another location conveniently available to the District Supervisor.] *the lessee must retain all the records listed in this section for 2 years and make them available at the District Supervisor's request*.	To require the lessee to maintain detailed drilling records at the facility or at the nearest field location after drilling is completed is unreasonable, and places an unnecessary recordkeeping burden on the operator. We do maintain these records; however, they are typically maintained in a central record center. The need to maintain test results in the field after the drill operations are completed is unclear. Should the need to review these records arise, they can be supplied at that time.	We deleted paragraph (f) and moved the recordkeeping requirements to §§ 250.466 and 250.467. Section 250.466 requires you to keep drilling records onsite during drilling operations. After completion of drilling activities, you may keep all records at a location of your choice. A table in § 250.467 gives the time periods for keeping all records.
250.440	You must design, install, maintain, *test* and use the BOP system and system components to ensure well control * * *.	Include test in the proposed text to be complete and consistent with the existing requirements.	We made the suggested change.
250.441(b)	(b) Delete	We strongly recommend that this requirement be eliminated. We have reviewed the description of the incidents used by the MMS to justify the proposed requirement to install blind-shear rams in all BOP stacks and disagree with the conclusion that they support the need to require the installation of blind-shear rams. Furthermore, a 13⅝ inch blind-shear rams would cost the drilling contractor an estimated $82,000 plus transportation and installation costs. The total estimated cost imposed by this requirement would be $150,000 per stack.	MMS did not make the suggested change. See response to comments in the previous part of the preamble. As for the $150,000 cost per stack cited by OOC, we have used a cost of $175,000 in our evaluation of impacts.
250.442(b)	(b) You must install a subsea accumulator closing unit, *or equivalent systems* to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. The [subsea] accumulator must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells. The District Supervisor may approve a suitable alternative method.	Many BOP stacks on floating drilling rigs currently in operation do not meet the proposed requirement to install a subsea accumulator. In lieu of subsea accumulators, the inclusion of redundant power/control lines provides the equivalent protection necessary. Therefore, we recommend the inclusion of the statement ''or equivalent system'' to the proposed language.	Our changes to this paragraph follow the suggested changes (see § 250.442(c)).

Proposed section	OOC comments	OOC rationale	MMS response
250.442(d)	(d) Before removing the marine drilling riser, you must displace the riser with seawater, *except in the case of an emergency riser disconnect*, You must* * *.	Drillships and semi submersible drilling rigs with automatic station keeping (ASK) systems may experience ASK failures at which time the well must be isolated with the BOP and the marine riser disconnection immediately to prevent damage to well, equipment, and rig. It is therefore impractical to displace the marine riser with seawater prior to an emergency riser disconnect.	We did not make this suggested change. MMS realizes that during an emergency you will not be able to displace the riser with seawater, but this specific case does not need to be addressed in the regulations (see § 250.442(e)).
250.447(b)	(b) Before 14 days have elapsed since your last BOP pressure test, you must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Supervisor may [require more frequent testing] *require the test to be performed before midnight on the 7th day following the conclusion of the previous test,* if conditions or BOP performance warrant; and	More frequent testing without a specified interval is too broad.	We did not make the suggested change. MMS sees no reason to set a fixed BOP testing interval for when the District Supervisor may require more frequent testing. MMS may choose a test interval between 7 and 14 days depending on conditions or performance. BOP performance that warrants testing at less than 7-day intervals would likely lead to shutting in the drilling unit until you fix the problems.
250.448(b)	(b) High Pressure tests for ram type * * * Clarity requested.	OOC recognizes and appreciates MMS efforts to allow for BOP high-pressure tests requirements to include either testing to rated working pressure, or to 500 psi above the maximum allowable Surface Pressure (MASP) for the applicable section of the hole. However, we recommend that the proposed rule include acceptable methods for calculating MASP, to provide clarity.	MMS will not publish a list of acceptable methods to calculate MASP in the regulations. We don't believe that it is appropriate to limit the number of acceptable methods nor do we believe that such a list would provide clarity.
250.448(c)	(c) High pressure test for annular-type BOPs. The high pressure test must equal 70 percent of the rated 70 percent of the rated working pressure of the equipment, *or as otherwise approved by the District Supervisor*.	Currently approved procedures for testing annular preventers allow for testing to a pressure less than 70% of the working pressure, such as testing to the MASP.	We changed the paragraph to read ''The high pressure test must equal 70% of the rated working pressure of the equipment or to a pressure approved in your APD.''
250.450(c)	(c) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. [For subsea BOP systems, you must also record the closing times for annular and ram preventers.] You may reference a BOP test plan if it is available at the facility.	The requirement to record closing times should be removed. This requirement is not a common practice. Furthermore, there is no requirement for maximum closing time of a BOP, and it is unclear how the measurement of closing time would be determined (is it from the time the button is pushed until the fluid flow stop, or the time it takes the ram to fully stroke?). We do not see the value added by recording this time. Either, a BOP stack functions properly or not.	Section 250.442(c) requires that ''the accumulator system equipment must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53.'' Section 13.3.5 in API RP 53 says ''For subsea installations, the BOP control system should be capable of closing each ram BOP in 45 seconds or less. Closing should not exceed 60 seconds for annular BOPs.'' As discussed in the preamble of the proposed rule, we incorporated API RP 53 by reference so that both industry and MMS would have guidelines for determining the minimum requirements and performance standards for subsea accumulators and BOP systems. As for the measurement of closing times, the RP states that ''the measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed, effecting a seal. A BOP is considered closed when the regulated operating pressure has recovered to its nominal setting.''

Proposed section	OOC comments	OOC rationale	MMS response
250.450(g)	(g) After drilling is completed, [retain all the records listed in this section for 2 years at the facility, at the lessee's field office nearest to the facility, or at another location conveniently available to the District Supervisor.] *the lessee must retain all the records listed in this section for 2 years and make them available at the District Supervisor's request*.	To require the lessee to maintain detailed drilling records at the facility or at the nearest field office nearest field location after drilling operations are completed is unreasonable, and places an unnecessary recordkeeping burden on the operator. We do not maintain these records; however, they are typically maintained in a central record center. The need to maintain test results in the field after the drill operations are completed is unclear. Should the need to review these records arise, they can be supplied at that time.	We deleted paragraph (g) and moved the record-keeping requirements to §§ 250.466 and 250.467. See previous discussion on § 250.434.
250.457(a)	(a) You must have and maintain drilling fluid-testing equipment on the drilling rig at all times. You must test the drilling fluid, when circulating at least once each tour or more frequently if conditions warrant. You must perform the tests according to industry-accepted practices. Tests must include density, viscosity, and gel strength; hydrogenion concentration; filtration; and any other tests the District Supervisor requires *for monitoring and maintaining drilling fluid quality for safe operations, prevention of downhole equipment problems and for the detection of kicks.* You must record * * *.	There are many times on a rig when circulation does not occur during a tour, or longer, and testing twice per day (once each tour) has no added value. Therefore, we recommend that this be a requirement during circulation only. Furthermore, the proposed text is too broad in regards to what type and why might the District Supervisor require additional test. The recommended language is consistent with the existing requirements.	We agree with the comment and moved the paragraph to become § 250.456(i). The new paragraph says: "When circulating, you must test the drilling fluid at least once each tour or more frequently if conditions warrant. You tests must conform to industry-accepted practices and include density, viscosity, and gel and gel strength; hydrogenion concentration; filtration; and any other tests the District Supervisor requires for monitoring drilling fluid quality, prevention of downhole equipment problems and for kick detection. You must record . . . ."
250.460(a)	Clarity requested	The proposed language is confusing. The title of this section is "What are the requirements for well testing?" However, paragraph (a) discusses determining formation characteristics using formation fluid samples and logging. It seems appropriate to put this paragraph in a section titled "what type samples, survey and tests of the formation are required." Please refer to 30 CFR 250.401(e) in the existing regulations.	We agree with the comment that the two paragraphs don't fit under this title. We moved paragraph (a) to its own section (now § 250.407 "What tests must I conduct to determine reservoir characteristics?)" under general requirements. We then re-titled this section "What are the requirements for conducting a well test?"
250.461(a)	(a) Survey requirements for a vertical well: (1) You must conduct inclination surveys on each vertical well and [digitally] record the results. Survey intervals may not exceed 1,000 feet during the normal course of drilling. (2) You must also conduct a directional survey that provides both inclination and azimuth, *and digitally record the results in electronic format:*	Digitally recording inclination surveys while drilling a vertical well is not necessary or practical. Inclination surveys are used as a process control check to ensure that the well remains near vertical. The subsequent surveys, which include both inclination and azimuth, can be digitally recorded in electronic format. The phrase "electronic format" has been add to clarify that the record should be stored electronically for submittal to MMS, not record as "fingers" on a paper copy.	We made the suggested changes.
250.461(e)	(e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder, *if the leaseholder has requested the survey*.	The adjacent leaseholder should request the survey.	We revised the paragraph by adding the following sentence: "This could occur when the adjoining leaseholder requests a copy of the survey for the protection of correlative rights."
250.462(d)	(d) MMS ordered drill. An MMS authorized representative. The MMS representative will consult with *your onsite representative* before requiring the drill.	Clarifies who will be consulted prior to conducting the drill.	We made the suggested change.

Proposed section	OOC comments	OOC rationale	MMS response
250.465(a)(1)	Receive written or oral approval from the District Supervisor before you begin the intended operation. If you get an oral approval, you must submit form MMS–124 [within 72 hours] *no later than the end of the 3rd business day following the oral approval.* In all cases, you must meet the additional requirements in paragraph (b) of this section.	With weekends and holidays, it is often difficult to meet the 72-hour limitation.	We made the suggested change.
250.466(g)	(g) All other information required by the District Supervisor *in order to evaluate resource evaluation, waste prevention, conservation of natural resources, protection of correlative rights, safety or protection of the environment*.	Proposed language is very broad. The recommended language clarifies under what circumstances will additional information be requested.	We made the suggested changes.
250.467	Delete section	As written, this section appears to be for informational purposes, rather than a requirement. Furthermore, the proposed language is vague. Line (a) discusses an NTL; Line (b) Specifies requirements for GOMR, but is silent on requirements for other regions. Line (c) as written appears that this is not mandatory, but at the discretion of the District Supervisor, and Line (d) eliminates the prescriptive requirements for legible, exact copies of service company records.	We renumbered this section to 250.469. The purpose of this section is to inform you what records the District Supervisor may require you to submit. The paragraphs identify the following: (a) well records, (b) paleontological reports and states that the Regional Supervisor may issue a Notice to Lessees that prescribes the manner, timeframe, and format for submitting this information, and (c) service company reports. We moved the requirements to submit form MMS—133, Well Activity Report, and daily drilling reports to the mandatory §§ 250.468(b) and (c).
250.515 (b) and 250.615 (b).	Delete this requirement	Please refer to rationale previously discussed in Section 250.441 of this document.	MMS did not make the suggested change. See our response to comments for § 250.441.

Procedural Matters

Regulatory Planning and Review (Executive Order 12866)

The Office of Mangement and Budget (OMB) has designated this a significant rule for OMB review under Executive Order 12866.

(1) The rule will not have an effect of $100 million or more on the economy. It will not adversely affect in a material way the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. The major purpose of this rule is the restructuring of the rule and simplifying the regulatory language. The restructuring and plain language revisions will not result in any economic effects to small or large entities. Some of the technical revisions will have a minor economic effect on lessees and drilling contractors.

Specifically, given the existing industry structure (*i.e.*, the number and size of affected regulated entities remain constant), MMS estimates the cost to implement the rule at $1 million annually.

In addition to the annual costs, the rule requires the installation of blind-shear rams in surface BOP stacks that will result in a one-time cost of $14,175,000. This rule allows a 3-year period for the installation of the new rams. The most significant benefits of preventing or minimizing some blowouts will be the reduced risk of injury or fatality to personnel and of environmental damage. Property damages (including lost productivity) resulting from blowouts will also be reduced by this final rule. Property and financial damages from a blowout or near blowout can range from minimal damage to a facility and the loss of a day's activity to the total loss of the drilling rig and production facility.

MMS believes that the installation of blind-shear rams in surface BOP stacks could prevent or minimize approximately one blowout every 2 years. This estimate comes from the 5 incidents that MMS identified where a blind-shear ram had helped or could have helped prevent or minimize a blowout over the past 10-year period (1992 to present). Considering that a single blowout could cause multiple fatalities, injuries, and tens of millions of dollars in property damage and financial losses, MMS believes that the benefits of this requirement will more than offset the cost of this new requirement.

(2) This rule will not create a serious inconsistency or otherwise interfere with an action taken or planned by another agency. The rule does not affect how lessees or operators interact with other agencies. Nor does this rule affect how MMS will interact with other agencies.

(3) This rule does not alter the budgetary effects or entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients. The rule only addresses the regulatory requirements for obtaining permission to drill on the OCS and the safety of drilling operations.

(4) OMB has determined that this rule raises novel legal or policy issues. The rule has some new policy issues, such as requiring minimum BOP maintenance requirements. OMB has determined that these issues make this rule a significant rule as defined in Executive Order 12866.

Regulatory Flexibility (RF) Act

The Department of the Interior (DOI) certifies that this rule will not have a significant economic effect on a substantial number of small entities under the RF Act (5 U.S.C. 601 *et seq.*). This rule applies to all lessees and drilling contractors that operate on the OCS. Small lessees and drilling contractors that operate under this final rule would fall under the Small Business Administration's (SBA) North American Industry Classification System codes 211111, Crude Petroleum and Natural Gas Extraction, and 213111 Drilling Oil and Gas Wells. Under these codes, SBA considers all companies with fewer than 500 employees to be a small business. Given the variability in the industry due to changes in the relative prices of oil and natural gas, the numbers of small entities affected by the rule may change over time. Based on data from 1998, we estimate that of the 130 lessees that explore for and produce oil and gas on the OCS, approximately 90 are small businesses (70 percent). We also estimate that 10 drilling contractors operate on the OCS, and none of those drilling contractors are classified as a small business. The number of drilling contractors is based on current drilling activity on the OCS, and the size of each drilling contractor is based on research into company statistics.

Drilling requirement costs will be borne by the OCS lessees who explore for and produce oil and are dependent on the number of wells drilled. We estimate that the total annual cost of the new drilling requirements in this rule to be approximately $670,000, as shown in the following table. The table also shows the estimated cost per well for the approximately 700 wells drilled annually on the OCS using a surface BOP stack.

ESTIMATED COSTS OF ADDITIONAL DRILLING REQUIREMENTS

Cost	Cost per well	Total cost for 700 wells drilled annually
One hour per well additional evaluation time on cementing operations @ $100	$100	$70,000
One hour per well additional drilling rig rental @ $850	850	$595,000
Annual reporting and paperwork burden—140 hours @ $50	10	$7,000
Total	960	$672,000

*The annual reporting and paperwork burden for the entire subpart D, ''Oil and Gas Drilling Operations'' is 111,209 hours as indicated in the Paperwork Reduction Act of 1995 section of this preamble. However, the new burden added when the this rule was proposed is only 140 hours (§ 250.403–100 hours; § 250.460(b)–30 hours; and § 250.461(e)—10 hours).

As indicated in the table, the estimated cost per well is about $1,000. Based on drilling data from 1999, we estimate that the 90 small businesses that explore for and produce oil and gas on the OCS drill about 300 of the 700 wells drilled annually on the OCS using a surface BOP stack. Thus, with the small businesses drilling an average of 3⅓ wells per year, the annual economic effect for each small business is about $3,300, or about $300,000 in total. The estimated additional cost of $1,000 per well is quite small (about .02 percent) when compared to the $5 million average cost of drilling a well. Based on this very low percentage of well cost, we believe that these revisions to the regulations will not have a significant economic effect on any small lessee.

The estimated economic effect of the requirement to use blind-shear rams on surface BOP stacks is the cost to purchase the rams. This requirement imposes no reporting or recordkeeping burden. This requirement primarily will affect drilling contractors operating jackup and platform rigs on the OCS who will be required to purchase the rams. Using information from 2003, the cost for a set of 10,000 pounds per-square-inch rams and associated equipment is about $105,000. Some sets of rams for lower-rated BOP stacks will cost less, while a few sets of rams will cost more for higher-rated BOP stacks, but the average cost will remain at about $105,000.

In the proposed rule we estimated that drilling contractors would need to purchase a total of 80 blind-shear rams to meet the proposed requirements. We have revised that estimate to 135 sets of rams for reasons as discussed in our response to comments. At an average cost of about $105,000, the economic impact will be $14,175,000. The largest drilling contractor may need to purchase up to 40 sets of blind-shear rams, while one drilling contractor will not have to purchase any blind-shear rams because it has already installed blind-shear rams in all of its surface BOP stacks. When asked why, a company executive responded that it was a prudent safety measure. A large contractor may get a minor reduction in the cost with a bulk purchase, but this reduction should not significantly affect the competition between large and small contractors because the unit costs will not vary much. Purchase of the rams to meet the proposed requirements will be an initial one-time cost. A blind-shear ram should last for 20 years if properly maintained.

The blind-shear ram requirement should not hinder the ability of lessees or contractors, including small businesses, to conduct business on the OCS. The final rule provides for a 3-year period after the effective date for drilling contractors to plan and purchase the rams and associated equipment. This will allow contractors sufficient time to obtain the equipment.

The following table summarizes the estimated economic effects associated with this final rule.

Requirement	Frequency	Total cost	Cost to small businesses
New drilling rules	Annual	$672,000	$300,000
Use of blind-shear rams	One-time	14,175,000	0
Total		14,847,000	300,000

We do not believe that this rule will have a significant impact on the lessees and drilling contractors who explore for and produce oil and gas on the OCS, including those that are classified as small businesses.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small business about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the actions of MMS, call 1–888–REG–FAIR (1–888–734–3247). You may comment to the Small Business Administration without fear of retaliation. Disciplinary action for retaliation by an MMS employee may include suspension or termination from employment with the Department of the Interior.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is not a major rule under (5 U.S.C. 804(2)) the SBREFA. The rule:

(1) Does not have an annual effect on the economy of $100 million or more. As described above, we estimate that the annual cost of the rule to be approximately $672,000. The cost for the blind-shear rams will be $14,175,000, which will be spread over a 3-year period. This cost will not cause an annual effect on the economy of $100 million.

(2) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions. The minor increase in drilling costs will not change the way the oil and gas industry conducts business, nor will it affect regional oil and gas prices; therefore, it will not cause major cost increases for consumers, the oil and gas industry, or any Government agencies.

(3) Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or ability of United States-based enterprises to compete with foreign-based enterprises. All lessees and drilling contractors, regardless of nationality, will have to comply with the requirements of this rule. So the rule will not affect competition, employment, investment, productivity, innovation, or the ability of United States-based enterprises to compete with foreign-based enterprises.

Paperwork Reduction Act (PRA) of 1995

We examined the proposed rule and these final regulations under section 3507(d) of the PRA. The proposed rulemaking added only a few new information collection requirements, which we submitted to OMB for approval as part of the proposed rulemaking process. There have been some changes to the numbering of sections requiring the collection of information in the final regulations, as well as some clarifications. However, the final regulations do not impose any additional information collection paperwork burden.

MMS regulations in 30 CFR 250, subpart A, at §§ 250.140, 250.141, and 250.142 allow respondents to request the use of ''alternative procedures or equipment'' and ''departures'' to operating requirements. However, our information collection submission to OMB (1010–0114) indicated that the burden for these requests is covered under the applicable operating requirement. To account for these non-specific possibilities, as MMS renews the various collections covering subparts of the part 250 regulations and the other 30 CFR parts, as a standard procedure we are now including these requests as a ''line item'' in the regulation burden charts. Based on comments we received on the proposed subpart D rulemaking, §§ 250.408 and 250.409 of these final regulations specifically address these issues and a line item has been included in the burden chart for this collection. It should be reiterated that these requests are not new information collection requirements. However, this inclusion will ensure that the burden is not overlooked for some operating requirements and will provide for any oversight.

Because of the adjustments discussed in the preceding paragraphs and section numbering changes, before publication, we again submitted the final subpart D information collection to OMB and OMB approved them under OMB control number 1010—0141, with a current expiration date of January 28, 2003. 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 title of the collection of information for this final rule is ''30 CFR 250, Subpart D—Oil and Gas Drilling Operations.'' Respondents include approximately 130 Federal OCS oil and gas or sulphur lessees. The frequency of response varies, depending upon the requirement. Responses are mandatory. MMS will protect proprietary information according to the Freedom of Information Act and 30 CFR 250.196, ''Data and information to be made available to the public.''

The final regulations convert into plain language and restructure the requirements for oil and gas drilling operations. The approved information collection for this final rule will supersede the collection for current subpart D regulations (OMB control number 1010–0053), which we will cancel when the new subpart D regulations take effect.

We estimate the total annual paperwork ''hour'' burden for the final rule to be 111,209 hours. Following is a breakdown of the hour burden estimate.

Citation 30 CFR 250 Subpart D	Reporting and recordkeeping requirement	Hour burden	Average number per year	Annual burden hours
402(b)	Request approval to use blind or blind-shear ram or pipe rams and inside BOP.	.25	6 requests	2
403	Notify MMS of drilling rig movement on or off drilling location	.1	20 notices	2
	In Gulf of Mexico OCS Region, rig movements reported on form MMS–144—burden covered under 1010–0150.			
408, 409	Apply for use alternative procedures and/or departures not requested in MMS forms (including discussions with MMS and approvals.	1	20% of 1,200 drilling ops. = 240.	240
408, 409; 410–418, plus various other references in subpart D.	Apply for permit to drill and requests for various approvals required in subpart D (including §§ 250.423, 424, 442(c), 451(g), 456(f)) and obtained via forms MMS–123 (Application for Permit to Drill) and MMS–123S (Supplemental APD Information Sheet), and supporting information and notices to MMS—burden covered under 1010–0044 and 1010–0131.			0
410(a)(3), 417(b)	Reference to Exploration Plan, Development and Production Plan, Development Operations Coordination Document (30 CFR 250, subpart B)—burden covered under 1010–0049.			0
417(a), (b)	Collect and report additional information on case-by-case basis if sufficient information is not available.	4	1 report	4
417(c)	Submit 3rd party review of drilling unit according to 30 CFR 250, subpart I—burden covered under 1010–0058.			0
418(e)	Submit welding and burning plan according to 30 CFR 250, subpart A—burden covered under 1010–0114			0
421; 423; 428	Submit casing and cementing program and revisions or changes	2	20% of 1,200 drilling ops. = 240.	480
424	Caliper, pressure test, or evaluate casing; submit evaluation results; request approval before resuming operations or beginning repairs (every 30 days during prolonged drilling).	5	20% of 1,200 wells = 240.	1,200
456(c), (f)	Perform various calculations; post information (on occasion, daily, weekly).	.25	144 drilling rigs × 52 =7,488.	1,872
459(a)(3)	Request exception to procedure for protecting negative pressure area.	2	5 requests	10
460; 465	Submit revised plans, changes, well/drilling records, etc., on forms MMS–124 (Application for Permit to Modify) or MMS–125 (End of Operations Report)—burden covered under 1010–0045 and 1010–0046			0
460	Submit plans for well testing and notify MMS before test	2	15 plans	30
461(e)	Provide copy of well directional survey to affected leaseholder	1	10 occasions	10
462(a)	Prepare and post well control drill plan for crew members	3	26 plans	78
463(b)	Request field drilling rules be established, amended, or canceled	2.5	6 requests	15
468(a)	Submit well logs	1.5	1,200 logs/surveys	1,800
	Submit directional and vertical-well surveys	.5	1,200 reports	600
	Submit velocity profiles and surveys	.25	55 reports	14
	Submit core analyses	.25	150 analyses	38
468(b); 465(b)(3)	In the GOM OCS Region, submit drilling activity reports on form MMS–133 (Well Activity Report)—burden covered under 1010–0132			0
468(c)	In the Pacific and Alaska OCS Regions during drilling operations, submit daily drilling reports.	1	14 wells × 365 days × 20% = 1,022.	1,022
469	As specified by region, submit well records, paleontological interpretations or reports, service company reports, and other reports or records of operations.	.25	300 submissions	75
490(c)(4), (d)	Submit request for reclassification of H_2S zone; notify MMS if conditions change.	1.7	27 responses	46
490(f); also referred to in 418(d).	Submit contingency plans for operations in H_2S areas (16 drilling, 5 work-over, 6 production).	10	27 plans	270
490(i)	Display warning signs—no burden as facilities would display warning signs and use other visual and audible systems.			0
490(j)(12)	Propose alternatives to minimize or eliminate SO_2 hazards—submitted with contingency plans—burden covered under 250.490(f).			0
490(j)(13)(vi)	Label breathing air bottles—no burden as supplier normally labels bottles; facilities would routinely label if not.			0
490(l)	Notify (phone) MMS of unplanned H_2S releases (approx. 2/year)	.2	49 facilities × 2 = 98	20
490(o)(5)	Request approval to use drill pipe for well testing	2	3 requests	6

Citation 30 CFR 250 Subpart D	Reporting and recordkeeping requirement	Hour burden	Average number per year	Annual burden hours
490(q)(1)	Seal and mark for the presence of H_2S cores to be transported—no burden as facilities would routinely mark transported cores.			0
490(q)(9)	Request approval to use gas containing H_2S for instrument gas	2	3 requests	6
490(q)(12)	Analyze produced water disposed of for H_2S content and submit results to MMS on occasion (approx. weekly).	2.8	4 production platforms × 52 = 208.	582
Reporting Subtotal			12,590 Responses	8,422
404	Perform operational check of crown block safety device; record results (weekly).	.1	144 drilling rigs × 52 = 7,488.	749
426	Perform pressure test on all casing strings and drilling liner lap; record results.	2	144 drilling rigs × approx. 50 per rig = 7,200.	14,400
427(a)	Perform pressure-integrity tests and related hole-behavior observations; record results.	4	425 tests	1,700
434; 467	Perform diverter tests when installed and once every 7 days; actuate system at least once every 24-hour period; record results (average 2 per drilling operation).	2	1,200 drilling ops. × 2 = 2,400.	4,800
450; 467	Perform BOP pressure tests, actuations and inspections when installed; at a minimum every 14 days; as stated for components; record results.	6	144 drilling rigs × approx. 35 per rig = 5,040.	30,240
450, 467	Function test annulars and rams; document results every 7 days between BOP tests (biweekly). Note: this test is part of BOP test when BOP test is conducted.	.16	144 drilling rigs × approx. 20 per rig = 2,880.	461
451(c)	Record reason for postponing BOP test (on occasion—approx. 2/year).	.1	144 drilling rigs × 2 = 288.	29
456(b), (i); 458(b)	Record each drilling fluid circulation; test drilling fluid, record results; record daily inventory of drilling fluid/materials; test and recalibrate gas detectors; record results (on occasion, daily, weekly, quarterly).	1.25	144 drilling rigs × 52 = 7,488.	9,360
462(c)	Perform well-control drills; record results (2 crews weekly)	1	144 drilling rigs × 2 crews × 52 = 14,976.	14,976
466, 467	Retain drilling records for 90 days after drilling is complete; retain casing/liner pressure, diverter, and BOP for 2 years; retain well completion/well workover until well is permanently plugged/abandoned or lease assigned.	1.5	Annual records maintenance for 1,200 wells.	1,800
490(g)(2), (g)(5)	Conduct H_2S training; post safety instructions; document training on occasion and annual refresher (approx. 2/year).	2	49 facilities × 2 = 98	196
490(h)(2)	Conduct weekly drills and safety meetings; document attendance	1	49 facilities × 52 = 2,548	2,548
490(j)(8)	Test H_2S detection and monitoring sensors during drilling; record testing and calibrations on occasion, daily during drilling (approx. 12 sensors per rig).	2	26 drilling rigs × 365 days = 9,490.	18,980
490(j)(8)	Test H_2S detection and monitoring sensors every 14 days during production; record testing and calibrations (approx. 30 sensors/5 platforms + approx. 42 sensors/23 platforms).	3.5	28 production platforms × 26 = 728.	2,548
Recordkeeping Subtotal.			130 Record-keepers	102,787
Total Hour Burden.			12,720	111,209

Federalism (Executive Order 13132)

According to Executive Order 13132, this rule does not have Federalism implications. This rule does not substantially and directly affect the relationship between the Federal and State Governments. The rule applies to lessees and drilling contractors that operate on the OCS. This rule does not impose costs on States or localities. Any costs will be the responsibility of the lessees and drilling contractors.

Takings Implication Assessment (Executive Order 12630)

According to Executive Order 12630, the rule does not have significant Takings Implications. A Takings Implication Assessment is not required. The rule revises existing operation regulations. It does not prevent any lessee, operator, or drilling contractor from performing operations on the OCS, provided they follow the regulations. Thus, MMS did not need to prepare a Takings Implication Assessment under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Energy Supply, Distribution, or Use (Executive Order 13211)

Although OMB has designated this a significant rule under Executive Order 12866, it does not have a significant effect on energy supply, distribution, or use. The rule essentially clarifies the current regulatory requirements for oil and gas drilling on the OCS. The rule also adds a new requirement (blind-shear rams in surface BOP stacks) that will result in a one-time cost to the industry of $14,175,000. However, the increased safety aspects associated with the new requirement along with the potential for reduced property damages and financial losses will offset the $14,175,000 cost of the new rams. Accordingly the new requirement will not cause a reduction in crude oil supply or an increase in energy prices.

Civil Justice Reform (Executive Order 12988)

According to Executive Order 12988, the Office of the Solicitor has determined that this rule does not unduly burden the judicial system and does meet the requirements of sections 3(a) and 3(b)(2) of the Order.

National Environmental Policy Act (NEPA)

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. An environmental assessment is not required.

Unfunded Mandates Reform Act (UMRA) of 1995 (Executive Order 12866)

This rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have any Federal mandates, nor does the rule have a significant or unique effect on State, local, or tribal governments or the private sector. A statement containing the information required by the UMRA (2 U.S.C. 1531 *et seq.*) is not required.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Public lands-mineral resources, Public lands-rights-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Dated: October 24, 2002.

Rebecca W. Watson,

Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) amends 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: 43 U.S.C. 1331 *et seq.*

2. In § 250.102, in the table in paragraph (b), paragraph (1) is revised to read as follows:

For information about	Refer to
(1) Applications for permit to drill	§ 250.410
* * * * *	*

3. In § 250.105, in the definition for Facility (3), the citation ''§ 250.417(b)'' is revised to read ''§ 250.490(b)''.

4. In § 250.198, in the table in paragraph (e), the following changes are made in alphanumeric order:

A. Add an entry for API RP 53 as set forth below.

B. Revise the entries for ANSI Z88.2–1992, API RP 500, API RP 505, and NACE Standard MR0175–99 as set forth below.

250.198 Documents incorporated by reference.

* * * * *

(e) * * *

Title of documents	Incorporated by reference at
* * * * *	* *
ANSI Z88.2–1992, American National Standard for Respiratory Protection	§ 250.490(g)(4)(iv), (j)(13)(ii).
* * * * *	* *
API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997, API Stock No. G53003.	§ 250.442(c); § 250.446(a).
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class I, Division 1 and Division 2, Second Edition, November 1997, API Stock No. C50002.	§ 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3); (d)(4)(i); § 250.1629(b)(4)(i).
API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997, API Stock No. C50501.	§ 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3); (d)(4)(i); § 250.1629(b)(4)(i).
* * * * *	* *
NACE Standard MR0175–99, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, Revised January 1999, NACE Item No. 21302.	§ 250.490(p)(2).
* * * * *	* *

5. In § 250.199, in the table in paragraph (e), the OMB control number ''1010–0053'' cited in the entry for item (4) is revised to read ''1010–0141''.

6. In § 250.203, the following changes are made:

A. In paragraphs (b)(5)(i) and (b)(5)(ii), the citation ''250.417'' is revised to read ''250.490''.

B. In paragraph (p), the citation ''§ 250.414'' is revised to read ''§ 250.410 through§ 250.418''.

7. In § 250.204, the following changes are made:

A. In paragraphs (b)(2)(i) and (b)(2)(ii), the citation ''§ 250.417'' is revised to read § 250.490''.

B. In paragraph (t), the citation ''§ 250.414'' is revised to read ''§ 250.410 through § 250.418''.

8. In 30 CFR part 250, subpart D, § 250.417 is redesignated as § 250.490, §§ 250.400 through 250.416 are revised, and §§ 250.417 through 250.469 are added, and a new undesignated center heading is added preceding redesignated §§ 250.490 to read as set forth below. For the convenience of the reader, the table of contents for subpart D is also set forth below:

Subpart D—Oil and Gas Drilling Operations

Subpart D—Oil and Gas Drilling Operations

General Requirements

§ 250.400 Who is subject to the requirements of this subpart?

The requirements of this subpart apply to lessees, operating rights owners, operators, and their contractors and subcontractors.

§ 250.401 What must I do to keep wells under control?

You must take necessary precautions to keep wells under control at all times. You must:

(a) Use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick;

(b) Have a person onsite during drilling operations who represents your interests and can fulfill your responsibilities;

(c) Ensure that the toolpusher, operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subpart O; and

(e) Use and maintain equipment and materials necessary to ensure the safety and protection of personnel, equipment, natural resources, and the environment.

§ 250.402 When and how must I secure a well?

Whenever you interrupt drilling operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the device at an appropriate depth within a properly cemented casing string or liner.

(a) Among the events that may cause you to interrupt drilling operations are:

(1) Evacuation of the drilling crew;

(2) Inability to keep the drilling rig on location; or

(3) Repair to major drilling or well-control equipment.

(b) For floating drilling operations, the District Supervisor may approve the use of blind or blind-shear rams or pipe rams and an inside BOP if you don't have time to install a downhole safety device or if special circumstances occur.

§ 250.403 What drilling unit movements must I report?

(a) You must report the movement of all drilling units on and off drilling locations to the District Supervisor. This includes both MODU and platform rigs. You must inform the District Supervisor 24 hours before:

(1) The arrival of an MODU on location;

(2) The movement of a platform rig to a platform;

(3) The movement of a platform rig to another slot;

(4) The movement of an MODU to another slot; and

(5) The departure of an MODU from the location.

(b) You must provide the District Supervisor with the rig name, lease number, well number, and expected time of arrival or departure.

(c) In the Gulf of Mexico OCS Region, you must report drilling unit movements on form MMS–144, Rig Movement Notification Report.

§ 250.404 What are the requirements for the crown block?

You must have a crown block safety device that prevents the traveling block from striking the crown block. You must check the device for proper operation at least once per week and after each drill-line slipping operation and record the results of this operational check in the driller's report.

§ 250.405 What are the safety requirements for diesel engines used on a drilling rig?

You must equip each diesel engine with an air take device to shut down the diesel engine in the event of a runaway.

(a) For a diesel engine that is not continuously manned, you must equip the engine with an automatic shutdown device;

(b) For a diesel engine that is continuously manned, you may equip the engine with either an automatic or remote manual air intake shutdown device;

(c) You do not have to equip a diesel engine with an air intake device if it meets one of the following criteria:

(1) Starts a larger engine;

(2) Powers a firewater pump;

(3) Powers an emergency generator;

(4) Powers a BOP accumulator system;

(5) Provides air supply to divers or confined entry personnel;

(6) Powers temporary equipment on a nonproducing platform;

(7) Powers an escape capsule; or

(8) Powers a portable single-cylinder rig washer.

§ 250.406 What additional safety measures must I take when I conduct drilling operations on a platform that has producing wells or has other hydrocarbon flow?

You must take the following safety measures when you conduct drilling operations on a platform with producing wells or that has other hydrocarbon flow:

(a) You must install an emergency shutdown station near the driller's console;

(b) You must shut in all producible wells located in the affected wellbay below the surface and at the wellhead when:

(1) You move a drilling rig or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a drilling unit between wells on a platform;

(3) A mobile offshore drilling unit (MODU) moves within 500 feet of a platform. You may resume production once the MODU is in place, secured, and ready to begin drilling operations.

§ 250.407 What tests must I conduct to determine reservoir characteristics?

You must determine the presence, quantity, quality, and reservoir characteristics of oil, gas, sulphur, and water in the formations penetrated by logging, formation sampling, or well testing.

§ 250.408 May I use alternative procedures or equipment during drilling operations?

You may use alternative procedures or equipment during drilling operations after receiving approval from the District Supervisor. You must identify and discuss your proposed alternative procedures or equipment in your Application for Permit to Drill (APD) (see § 250.414(h)). Procedures for obtaining approval are described in section 250.141 of this part.

§ 250.409 May I obtain departures from these drilling requirements?

The District Supervisor may approve departures from the drilling requirements specified in this subpart. You may apply for a departure from drilling requirements by writing to the District Supervisor. You should identify and discuss the departure you are requesting in your APD (see § 250.414(h)).

Applying for a Permit To Drill

§ 250.410 How do I obtain approval to drill a well?

You must obtain written approval from the District Supervisor before you begin drilling any well or before you sidetrack, bypass, or deepen a well. To obtain approval, you must:

(a) Submit the information required by § 250.411 through 250.418;

(b) Include the well in your approved Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD);

(c) Meet the oil spill financial responsibility requirements for offshore facilities as required by 30 CFR part 253; and

(d) Submit the following forms to the District Supervisor:

(1) An original and two complete copies of form MMS–123, Application for a Permit to Drill (APD), and form MMS–123S, Supplemental APD Information Sheet; and

(2) A separate public information copy of forms MMS–123 and MMS–123S that meets the requirements of § 250.127.

§ 250.411 What information must I submit with my application?

In addition to forms MMS–123 and MMS–123S, you must include the information described in the following table.

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well	§ 250.412
(b) Design criteria used for the proposed well	§ 250.413
(c) Drilling prognosis	§ 250.414
(d) Casing and cementing programs	§ 250.415
(e) Diverter and BOP systems descriptions	§ 250.416
(f) Requirements for using an MODU	§ 250.417

Information that you must include with an APD	Where to find a description
(g) Additional information	§ 250.418

§ 250.412 What requirements must the location plat meet?

The location plat must:

(a) Have a scale of 1:24,000 (1 inch = 2,000 feet);

(b) Show the surface and subsurface locations of the proposed well and all the wells in the vicinity;

(c) Show the surface and subsurface locations of the proposed well in feet or meters from the block line;

(d) Contain the longitude and latitude coordinates, and either Universal Transverse Mercator grid-system coordinates or state plane coordinates in the Lambert or Transverse Mercator Projection system for the surface and subsurface locations of the proposed well; and

(e) State the units and geodetic datum (including whether the datum is North American Datum 27 or 83) for these coordinates. If the datum was converted, you must state the method used for this conversion, since the various methods may produce different values.

§ 250.413 What must my description of well drilling design criteria address?

Your description of well drilling design criteria must address:

(a) Pore pressures;

(b) Formation fracture gradients, adjusted for water depth;

(c) Potential lost circulation zones;

(d) Drilling fluid weights;

(e) Casing setting depths;

(f) Maximum anticipated surface pressures. For this section, maximum anticipated surface pressures are the pressures that you reasonably expect to be exerted upon a casing string and its related wellhead equipment. In calculating maximum anticipated surface pressures, you must consider: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions. You must include the calculations used to determine the pressures for the drilling and the completion phases, including the anticipated surface pressure used for designing the production string;

(g) A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, and casing setting depths in true vertical measurements;

(h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions if not previously submitted; and

(i) Permafrost zones, if applicable.

§ 250.414 What must my drilling prognosis include?

Your drilling prognosis must include a brief description of the procedures you will follow in drilling the well. This prognosis includes but is not limited to the following:

(a) Projected plans for coring at specified depths;

(b) Projected plans for logging;

(c) Planned safe drilling margin between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by § 250.413(g);

(d) Estimated depths to the top of significant marker formations;

(e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids;

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

(h) A list and description of all requests for using alternative procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternative procedures afford an equal or greater degree of protection, safety, or performance, or why you need the departures; and

(i) Projected plans for well testing (refer to § 250.460 for safety requirements).

§ 250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

(a) Hole sizes and casing sizes, including: weights; grades; collapse, and burst values; types of connection; and setting depths (measured and true vertical depth (TVD));

(b) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values;

(c) Type and amount of cement (in cubic feet) planned for each casing string; and

(d) In areas containing permafrost, setting depths for conductor and surface casing based on the anticipated depth of the permafrost. Your program must provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control.

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

You must include in the diverter and BOP descriptions:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows: (1) the size of the annular BOP installed in the diverter housing;

(2) spool outlet internal diameter(s);

(3) diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) valve type, size, working pressure rating, and location;

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

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

(e) Information that shows the blind-shear rams installed in the BOP stack (both surface and subsea stacks) are capable of shearing the drill pipe in the hole under maximum anticipated surface pressures.

§ 250.417 What must I provide if I plan to use a mobile offshore drilling unit (MODU)?

If you plan to use a MODU, you must provide:

(a) *Fitness requirements.* You must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD, the District Supervisor may approve your APD but require you to collect and report this information during operations. Under this circumstance, the District Supervisor has the right to revoke the approval of the APD if information collected during operations show that the drilling unit is not capable of performing at the proposed location.

(b) *Foundation requirements.* You must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed drilling unit. If you provided sufficient site-specific information in your EP, DPP, or DOCD, you may reference that information. The District Supervisor may require you to conduct additional surveys and soil borings before approving the APD if additional information is needed to make a determination that the conditions are capable of supporting the drilling unit.

(c) *Frontier areas.* (1) If the design of the drilling unit you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Supervisor may require you to submit a third-party review of the unit's design. If required, you must obtain the third-party review according to § 250.903. You may submit this information before submitting an APD.

(2) If you plan to drill in a frontier area, you must have a contingency plan that addresses design and operating limitations of the drilling unit. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of drilling or rig operations to remedy various operational or environmental situations (*e.g.* vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) *U.S. Coast Guard (USCG) Documentation.* You must provide the current Certificate of Inspection or Letter of Compliance from the USCG. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Floating drilling unit.* If you use a floating drilling unit, you must indicate that you have a contingency plan for moving off location in an emergency situation.

(f) *Inspection of unit.* The drilling unit must be available for inspection by the District Supervisor before commencing operations.

(g) Once the District Supervisor has approved a MODU for use, you do not need to re-submit the information required by this section for another APD to use the same MODU unless changes in equipment affect its rated capacity to operate in the District.

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

You must include the following with the APD:

(a) Rated capacities of the drilling rig and major drilling equipment, if not already on file with the appropriate District office;

(b) A drilling fluids program that includes the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site;

(c) A proposed directional plot if the well is to be directionally drilled;

(d) A Hydrogen Sulfide Contingency Plan (see § 250.490), if applicable, and not previously submitted;

(e) A welding plan (see §§ 250.109 to 250.113) if not previously submitted;

(f) In areas subject to subfreezing conditions, evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions;

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

(h) Such other information as the District Supervisor may require.

Casing and Cementing Requirements

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

You must case and cement all wells. Your casing and cementing programs must meet the requirements of this section and of §§ 250.421 through 250.428.

(a) *Casing and cementing program requirements.* Your casing and cementing programs must:

(1) Properly control formation pressures and fluids;

(2) Prevent the direct or indirect release of fluids from any stratum through the wellbore into offshore waters;

(3) Prevent communication between separate hydrocarbon-bearing strata;

(4) Protect freshwater aquifers from contamination; and

(5) Support unconsolidated sediments.

(b) *Casing requirements.* (1) You must design casing (including liners) to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof.

(2) The casing design must include safety measures that ensure well control during drilling and safe operations during the life of the well.

(c) *Cementing requirements.* You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out of the casing or before commencing completion operations.

§ 250.421 What are the casing and cementing requirements by type of casing string?

The table in this section identifies specific design, setting, and cementing requirements for casing strings and liners. For the purposes of subpart D, the casing strings in order of normal installation are as follows: drive or structural, conductor, surface, intermediate, and production casings (including liners). The District Supervisor may approve or prescribe other casing and cementing requirements where appropriate.

Casing type	Casing requirements	Cementing requirements
(a) Drive or Structural	Set by driving, jetting, or drilling to the minimum depth as approved or prescribed by the District Supervisor.	If you drilled a portion of this hole, you must use enough cement to fill the annular space back to the mudline.
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a glory hole, you must discuss the cement fill level with the District Supervisor.

Casing type	Casing requirements	Cementing requirements
(c) Surface	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths.	Use enough cement to fill the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.
(d) Intermediate	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well. As a minimum, you must cement the annular space 500 feet above the casing shoe and 500 feet above each zone to be isolated.
(e) Production	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe..	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.

§ 250.422 When may I resume drilling after cementing?

(a) After cementing surface, intermediate, or production casing (or liners), you may resume drilling after the cement has been held under pressure for 12 hours. For conductor casing, you may resume drilling after the cement has been held under pressure for 8 hours. One acceptable method of holding cement under pressure is to use float valves to hold the cement in place.

(b) If you plan to nipple down your diverter or BOP stack during the 8- or 12-hour waiting time, you must determine, before nippling down, when it will be safe to do so. You must base your determination on a knowledge of formation conditions, cement composition, effects of nippling down, presence of potential drilling hazards, well conditions during drilling, cementing, and post cementing, as well as past experience.

§ 250.423 What are the requirements for pressure testing casing?

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 re-cement, repair the casing, or run additional casing to provide a proper seal. The District Supervisor may approve or require other casing test pressures.

Casing type	Minimum test pressure
(a) Drive or Structural	Not required
(b) Conductor	200 psi
(c) Surface, Intermediate, and Production	70 percent of its minimum internal yield

§ 250.424 What are the requirements for prolonged drilling operations?

If wellbore operations continue for more than 30 days within a casing string run to the surface:

(a) You must stop drilling operations as soon as practicable, and evaluate the effects of the prolonged operations on continued drilling operations and the life of the well. At a minimum, you must:

(1) Caliper or pressure test the casing; and

(2) Report the results of your evaluation to the District Supervisor and obtain approval of those results before resuming operations.

(b) If casing integrity has deteriorated to a level below minimum safety factors, you must:

(1) Repair the casing or run another casing string; and

(2) Obtain approval from the District Supervisor before you begin repairs.

§ 250.425 What are the requirements for pressure testing liners?

(a) You must test each drilling liner (and liner-lap) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Supervisor may approve or require other liner test pressures.

(b) You must test each production liner (and liner-lap) to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.

(c) 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 re-cement, repair the liner, or run additional casing/liner to provide a proper seal.

§ 250.426 What are the recordkeeping requirements for casing and liner pressure tests?

You must record the time, date, and results of each pressure test in the driller's report maintained under standard industry practice. In addition, you must record each test on a pressure chart and have your onsite representative sign and date the test as being correct.

§ 250.427 What are the requirements for pressure integrity tests?

You must conduct a pressure integrity test below the surface casing or liner and all intermediate casings or liners. The District Supervisor may require you to run a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. You must conduct each pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD.

(a) You must use the pressure integrity test and related hole-behavior observations, such as pore-pressure test results, gas-cut drilling fluid, and well kicks to adjust the drilling fluid program and the setting depth of the next casing string. You must record all test results and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure in the driller's report.

(b) While drilling, you must maintain the safe drilling margin identified in the approved APD. When you cannot maintain this safe margin, you must suspend drilling operations and remedy the situation.

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

The table in this section describes actions that lessees must take when certain situations occur during casing and cementing activities.

If you encounter the following situation:	Then you must . . .
(a) Have unexpected formation pressures or conditions that warrant revising your casing design.	Submit a revised casing program to the District Supervisor for approval.
(b) Need to increase casing setting depths more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations.	Submit those changes to the District Supervisor for approval.
(c) Have indication of inadequate cement job (such as lost returns, cement channeling, or failure of equipment).	(1) Pressure test the casing shoe; (2) Run a temperature survey; (3) Run a cement bond log; or (4) Use a combination of these techniques.
(d) Inadequate cement job	Re-cement or take other remedial actions as approved by the District Supervisor.
(e) Primary cement job that did not isolate abnormal pressure intervals.	Isolate those intervals from normal pressures by squeeze cementing before you complete; suspend operations; or abandon the well, whichever occurs first.
(f) Decide to produce a well that was not originally contemplated for production.	Have at least two cemented casing strings (does not include liners) in the well. Note: All producing wells must have at least two cemented casing strings.
(g) Want to drill a well without setting conductor casing.	Submit geologic data and information to the District Supervisor that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging and drilling fluid-monitoring from wells previously drilled within 500 feet of the proposed well path down to the next casing point.
(h) Need to use less than required cement for the surface casing during floating drilling operations to provide protection from burst and collapse pressures.	Submit information to the District Supervisor that demonstrates the use of less cement is necessary.
(i) Cement across a permafrost zone	Use cement that sets before it freezes and has a low heat of hydration.
(j) Leave the annulus opposite a permafrost zone uncemented.	Fill the annulus with a liquid that has a freezing point below the minimum permafrost temperature and minimizes opposite a corrosion.

Diverter System Requirements

§ 250.430 When must I install a diverter system?

You must install a diverter system before you drill a conductor or surface hole. The diverter system consists of a diverter sealing element, diverter lines, and control systems. You must design, install, use, maintain, and test the diverter system to ensure proper diversion of gases, water, drilling fluid, and other materials away from facilities and personnel.

§ 250.431 What are the diverter design and installation requirements?

You must design and install your diverter system to:

(a) Use diverter spool outlets and diverter lines that have a nominal diameter of at least 10 inches for surface wellhead configurations and at least 12 inches for floating drilling operations;

(b) Use dual diverter lines arranged to provide for downwind diversion capability;

(c) Use at least two diverter control stations. One station must be on the drilling floor. The other station must be in a readily accessible location away from the drilling floor;

(d) Use only remote-controlled valves in the diverter lines. All valves in the diverter system must be full-opening. You may not install manual or butterfly valves in any part of the diverter system;

(e) Minimize the number of turns (only one 90-degree turn allowed for each line for bottom-founded drilling units) in the diverter lines, maximize the radius of curvature of turns, and target all right angles and sharp turns;

(f) Anchor and support the entire diverter system to prevent whipping and vibration; and

(g) Protect all diverter-control instruments and lines from possible damage by thrown or falling objects.

§ 250.432 How do I obtain a departure to diverter design and installation requirements?

The table below describes possible departures from the diverter requirements and the conditions required for each departure. To obtain one of these departures, you must have discussed the departure in your APD and received approval from the District Supervisor.

If you want a departure to:	Then you must...
(a) Use flexible hose for diverter lines instead of rigid pipe.	Use flexible hose that has integral end couplings.
(b) Use only one spool outlet for your diverter system.	(1) Have branch lines that meet the minimum internal diameter requirements; and (2) Provide downwind diversion capability.
(c) Use a spool with an outlet with an internal diameter of less than 10 inches on a surface wellhead.	Use a spool that has dual outlets with an internal diameter of at least 8 inches.
(d) Use a single diverter line for floating drilling operations on a dynamically positioned drillship.	Maintain an appropriate vessel heading to provide for downwind diversion.

§ 250.433 What are the diverter actuation and testing requirements?

When you install the diverter system, you must actuate the diverter sealing element, diverter valves, and diverter-control systems and control stations. You must also flow-test the vent lines.

(a) For drilling operations with a surface wellhead configuration, you must actuate the diverter system at least once every 24-hour period after the initial test. After you have nippled up on conductor casing, you must pressure-test the diverter-sealing element and diverter valves to a minimum of 200 psi. While the diverter is installed, you must conduct subsequent pressure tests within 7 days after the previous test.

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation.

(c) You must alternate actuations and tests between control stations.

§ 250.434 What are the recordkeeping requirements for diverter actuations and tests?

You must record the time, date, and results of all diverter actuations and tests in the driller's report. In addition, you must:

(a) Record the diverter pressure test on a pressure chart;

(b) Require your onsite representative to sign and date the pressure test chart;

(c) Identify the control station used during the test or actuation;

(d) Identify problems or irregularities observed during the testing or actuations and record actions taken to remedy the problems or irregularities; and

(e) Retain all pressure charts and reports pertaining to the diverter tests and actuations at the facility for the duration of drilling the well.

Blowout Preventer (BOP) System Requirements

§ 250.440 What are the general requirements for BOP systems and system components?

You must design, install, maintain, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. The BOP system includes the BOP stack and associated BOP systems and equipment.

§ 250.441 What are the requirements for a surface BOP stack?

(a) When you drill with a surface BOP stack, you must install the BOP system before drilling below surface casing. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind or blind-shear rams.

(b) No later than February 21, 2006, your surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an 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 the drill pipe that is in the hole.

(c) You must install an accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components. The system must perform with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost.

(d) In addition to the stack and accumulator system, you must install the associated BOP systems and equipment required by the regulations in this subpart.

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

(a) When you drill with a subsea BOP stack, you must install the BOP system before drilling below surface casing. The District Supervisor may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need.

(b) Your subsea BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams.

(c) You must install an accumulator closing system to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). The District Supervisor may approve a suitable alternative method.

(d) The BOP system must include an operable dual-pod control system to ensure proper and independent operation of the BOP system.

(e) Before removing the marine riser, you must displace the riser with seawater. You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition.

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

All BOP systems must include the following associated systems and related equipment:

(a) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components.

(b) At least two BOP control stations. One station must be on the drilling floor. You must locate the other station in a readily accessible location away from the drilling floor.

(c) Side outlets on the BOP stack for separate kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets.

(d) A choke and a kill line on the BOP stack. You must equip each line with two full-opening valves, one of which must be remote-controlled. For a subsea BOP system, both valves in each line must be remote-controlled. In addition:

(1) You must install the choke line above the bottom ram;

(2) You may install the kill line below the bottom ram; and

(3) For a surface BOP system, on the kill line you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

(e) A fill-up line above the uppermost BOP.

(f) Locking devices installed on the ram-type BOPs.

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

§ 250.444 What are the choke manifold requirements?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a rated working pressure at least as great as the rated working pressure of the ram BOPs.

§ 250.445 What are the requirements for kelly valves, inside BOPs, and drill-string safety valves?

You must use or provide the following BOP equipment during drilling operations:

(a) A kelly valve installed below the swivel (upper kelly valve);

(b) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack;

(c) If you drill with a mud motor and use drill pipe instead of a kelly, you must install one kelly valve above, and one strippable kelly valve below, the joint of drill pipe used in place of a kelly;

(d) On a top-drive system equipped with a remote-controlled valve, you must install a strippable kelly-type valve below the remote-controlled valve;

(e) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the drill string;

(f) A drill-string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the drill string;

(g) When running casing, you must have a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

(h) All required manual and remote-controlled kelly valves, drill-string safety valves, and comparable-type valves (*i.e.* kelly-type valve in a top-drive system) must be essentially full-opening; and

(i) The drilling crew must have ready access to a wrench to fit each manual valve.

§ 250.446 What are the BOP maintenance and inspection requirements?

(a) You must maintain your BOP system to ensure that the equipment functions properly. BOP maintenance 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).

(b) 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.

§ 250.447 When must I pressure test the BOP system?

You must pressure test your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill-string safety valve):

(a) When installed;

(b) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Supervisor may require more frequent testing if conditions or BOP performance warrant; and

(c) Before drilling out each string of casing or a liner. The District Supervisor may allow you to omit this test if you didn't remove the BOP stack to run the casing string or liner and the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your APD which casing strings and liners meet these criteria.

§ 250.448 What are the BOP pressure tests requirements?

When you pressure test the BOP system, you must conduct a low-pressure and a high-pressure test for each BOP component. You must conduct the low-pressure test before the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. Required test pressures are as follows:

(a) *Low-pressure test.* All low-pressure tests must be between 200 and 300 psi. Any initial pressure above 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 and reinitiate the test.

(b) *High-pressure test for ram-type BOPs, the choke manifold, and other BOP components.* The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated maximum anticipated surface pressure (MASP) for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Supervisor must have approved those test pressures in your APD.

(c) *High pressure test for annular-type BOPs.* The high pressure test must equal 70 percent of the rated working pressure of the equipment or to a pressure approved in your APD.

(d) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

§ 250.449 What additional BOP testing requirements must I meet?

You must meet the following additional BOP testing requirements:

(a) Use water to test a surface BOP system;

(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;

(c) Alternate tests between control stations and pods;

(d) Pressure test the blind or blind-shear ram BOP during stump tests and at all casing points;

(e) The interval between any blind or blind-shear ram BOP pressure tests may not exceed 30 days;

(f) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools;

(g) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly;

(h) Function test annular and ram BOPs every 7 days between pressure tests; and

(i) Actuate safety valves assembled with proper casing connections before running casing.

§ 250.450 What are the recordkeeping requirements for BOP tests?

You must record the time, date, and results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(a) Record BOP test pressures on pressure charts;

(b) Require your onsite representative to sign and date BOP test charts and reports as correct;

(c) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify the control station and pod used during the test;

(e) Identify any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities; and

(f) Retain all records, including pressure charts, driller's report, and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of drilling.

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

The table in this section describes actions that lessees must take when certain situations occur with BOP systems during drilling activities.

If you encounter the following situation:	Then you must . . .
(a) BOP equipment does not hold the required pressure during a test ...	Correct the problem and retest the affected equipment.
(b) Need to repair or replace a surface or subsea BOP system	First place the well in a safe, controlled condition (*e.g.*, before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck drill pipe.	Record the reason for postponing the test in the driller's report and conduct the required BOP test on the first trip out of the hole.
(d) BOP control station or pod that does not function properly	Suspend further drilling operations until that station or pod is operable.
(e) Want to drill with a tapered drill-string	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller-size drill string.
(f) Install casing rams in a BOP stack	Test the ram bonnets before running casing.
(g) Want to use an annular BOP with a rated working pressure less than the anticipated surface pressure.	Demonstrate that your well control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Supervisor.
(h) Use a subsea BOP system in an ice-scour area	Install the BOP stack in a glory hole. The glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

Drilling Fluid Requirements

§ 250.455 What are the general requirements for a drilling fluid program?

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

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

Your drilling fluid program must include the following safe practices:

(a) Before starting out of the hole with drill pipe, you must properly condition the drilling fluid. You must circulate a volume of drilling fluid equal to the annular volume with the drill pipe just off-bottom. You may omit this practice if documentation in the driller's report shows:

(1) No indication of formation fluid influx before starting to pull the drill pipe from the hole;

(2) The weight of returning drilling fluid is within 0.2 pounds per gallon (1.5 pounds per cubic foot) of the drilling fluid entering the hole; and

(3) Other drilling fluid properties are within the limits established by the program approved in the APD.

(b) Record each time you circulate drilling fluid in the hole in the driller's report;

(c) When coming out of the hole with drill pipe, you must fill the annulus with drilling fluid before the hydrostatic pressure decreases by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. You must calculate the number of stands of drill pipe and drill collars that you may pull before you must fill the hole. You must also calculate the equivalent drilling fluid volume needed to fill the hole. Both sets of numbers must be posted near the driller's station. You must use a mechanical, volumetric, or electronic device to measure the drilling fluid required to fill the hole;

(d) You must run and pull drill pipe and downhole tools at controlled rates so you do not swab or surge the well;

(e) When there is an indication of swabbing or influx of formation fluids, you must take appropriate measures to control the well. You must circulate and condition the well, on or near-bottom, unless well or drilling-fluid conditions prevent running the drill pipe back to the bottom;

(f) You must calculate and post near the driller's console the maximum pressures that you may safely contain under a shut-in BOP for each casing string. The pressures posted must consider the surface pressure at which the formation at the shoe would break down, the rated working pressure of the BOP stack, and 70 percent of casing burst (or casing test as approved by the District Supervisor). As a minimum, you must post the following two pressures:

(1) The surface pressure at which the shoe would break down. This calculation must consider the current drilling fluid weight in the hole; and

(2) The lesser of the BOP's rated working pressure or 70 percent of casing-burst pressure (or casing test otherwise approved by the District Supervisor);

(g) You must install an operable drilling fluid-gas separator and degasser before you begin drilling operations. You must maintain this equipment throughout the drilling of the well;

(h) Before pulling drill-stem test tools from the hole, you must circulate or reverse-circulate the test fluids in the hole. If circulating out test fluids is not feasible, you may bullhead test fluids out of the drill-stem test string and tools with an appropriate kill weight fluid;

(i) When circulating, you must test the drilling fluid at least once each hour, or more frequently if conditions warrant. Your tests must conform to industry-accepted practices and include density, viscosity, and gel strength; hydrogenion concentration; filtration; and any other tests the District Supervisor requires for monitoring and maintaining drilling fluid quality, prevention of downhole equipment problems and for kick detection. You must record the results of these tests in the drilling fluid report; and

(j) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

§ 250.457 What equipment is required to monitor drilling fluids?

Once you establish drilling fluid returns, you must install and maintain the following drilling fluid-system monitoring equipment throughout subsequent drilling operations. This equipment must have the following indicators on the rig floor:

(a) Pit level indicator to determine drilling fluid-pit volume gains and losses. This indicator must include both a visual and an audible warning device;

(b) Volume measuring device to accurately determine drilling fluid volumes required to fill the hole on trips;

(c) Return indicator devices that indicate the relationship between drilling fluid-return flow rate and pump discharge rate. This indicator must include both a visual and an audible warning device; and

(d) Gas-detecting equipment to monitor the drilling fluid returns. The indicator may be located in the drilling fluid-logging compartment or on the rig floor. If the indicators are only in the logging compartment, you must continually man the equipment and have a means of immediate communication with the rig floor. If the indicators are on the rig floor only, you must install an audible alarm.

§ 250.458 What quantities of drilling fluids are required?

(a) You must use, maintain, and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must determine those quantities based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

(b) You must record the daily inventories of drilling fluid and drilling fluid materials, including weight materials and additives in the drilling fluid report.

(c) If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

§ 250.459 What are the safety requirements for drilling fluid-handling areas?

You must classify drilling fluid-handling areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class I, Division 1 and Division 2 (incorporated by reference as specified in § 250.198); or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, Classified as Class 1, Zone 0, Zone 1, and Zone 2 (incorporated by reference as specified in § 250.198). In areas where dangerous concentrations of combustible gas may accumulate, you must install and maintain a ventilation system and gas monitors. Drilling fluid-handling areas must have the following safety equipment:

(a) A ventilation system capable of replacing the air once every 5 minutes or 1.0 cubic feet of air-volume flow per minute, per square foot of area, whichever is greater. In addition:

(1) If natural means provide adequate ventilation, then a mechanical ventilation system is not necessary;

(2) If a mechanical system does not run continuously, then it must activate when gas detectors indicate the presence of 1 percent or more of combustible gas by volume; and

(3) If discharges from a mechanical ventilation system may be hazardous, then you must maintain the drilling fluid-handling area at a negative pressure. You must protect the negative pressure area by using at least one of the following: a pressure-sensitive alarm, open-door alarms on each access to the area, automatic door-closing devices, air locks, or other devices approved by the District Supervisor;

(b) Gas detectors and alarms except in open areas where adequate ventilation is provided by natural means. You must test and recalibrate gas detectors quarterly. No more than 90 days may elapse between tests;

(c) Explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where you use air for pressuring equipment, you must locate the air intake outside of and as far as practicable from hazardous areas; and

(d) Alarms that activate when the mechanical ventilation system fails.

Other Drilling Requirements

§ 250.460 What are the requirements for conducting a well test?

(a) If you intend to conduct a well test, you must include your projected plans for the test with your APD (form MMS–123) or in an Application for Permit to Modify (APM) (form MMS–124). Your plans must include at least the following information:

(1) Estimated flowing and shut-in tubing pressures;

(2) Estimated flow rates and cumulative volumes;

(3) Time duration of flow, buildup, and drawdown periods;

(4) Description and rating of surface and subsurface test equipment;

(5) Schematic drawing, showing the layout of test equipment;

(6) Description of safety equipment, including gas detectors and fire-fighting equipment;

(7) Proposed methods to handle or transport produced fluids; and

(8) Description of the test procedures.

(b) You must give the District Supervisor at least 24-hours notice before starting a well test.

§ 250.461 What are the requirements for directional and inclination surveys?

For this subpart, MMS classifies a well as vertical if the calculated average of inclination readings does not exceed 3 degrees from the vertical.

(a) *Survey requirements for a vertical well.* (1) You must conduct inclination surveys on each vertical well and record the results. Survey intervals may not exceed 1,000 feet during the normal course of drilling;

(2) You must also conduct a directional survey that provides both inclination and azimuth, and digitally record the results in electronic format:

(i) Within 500 feet of setting surface or intermediate casing;

(ii) Within 500 feet of setting any liner; and

(iii) When you reach total depth.

(b) *Survey requirements for directional well.* You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle-changing portions of the hole may not exceed 100 feet.

(c) *Measurement while drilling.* You may use measurement-while-drilling technology if it meets the requirements of this section.

(d) *Composite survey requirements.*

(1) Your composite directional survey must show the interval from the bottom of the conductor casing to total depth. In the absence of conductor casing, the survey must show the interval from the bottom of the drive or structural casing to total depth; and

(2) You must correct all surveys to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction. Surveys must show the magnetic and grid corrections used and include a listing of the directionally computed inclinations and azimuths.

(e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder. This could occur when the adjoining leaseholder requests a copy of the survey for the protection of correlative rights.

§ 250.462 What are the requirements for well-control drills?

You must conduct a weekly well-control drill with each drilling crew. Your drill must familiarize the crew with its roles and functions so that all crew members can perform their duties promptly and efficiently.

(a) *Well-control drill plan.* You must prepare a well control drill plan for each well. Your plan must outline the assignments for each crew member and establish times to complete each portion of the drill. You must post a copy of the well control drill plan on the rig floor or bulletin board.

(b) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to drilling operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping.

(c) *Recordkeeping requirements.* For each drill, you must record the following in the driller's report:

(1) The time to be ready to close the diverter or BOP system; and

(2) The total time to complete the entire drill.

(d) *MMS ordered drill.* An MMS authorized representative may require you to conduct a well control drill during an MMS inspection. The MMS representative will consult with your onsite representative before requiring the drill.

§ 250.463 Who establishes field drilling rules?

(a) The District Supervisor may establish field drilling rules different from the requirements of this subpart when geological and engineering information shows that specific operating requirements are appropriate. You must comply with field drilling rules and nonconflicting requirements of this subpart. The District Supervisor may amend or cancel field drilling rules at any time.

(b) You may request the District Supervisor to establish, amend, or cancel field drilling rules.

Applying for a Permit to Modify and Well Records

§ 250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to MMS?

(a) You must submit an APM (form MMS–124) or an End of Operations Report (form MMS–125) and other materials to the Regional Supervisor as shown in the following table. You must also submit a public information copy of each form.

When you	Then you must	And
(1)Intend to revise your drilling plan, change major drilling equipment, or plugback.	Submit form MMS–124 or request oral approval.	Receive written or oral approval from the District Supervisor before you begin the intended operation. If you get an approval, you must submit form MMS–124 no later than the end of the 3rd business day following the oral approval. In all cases, or you must meet the additional requirements in paragraph (b) of this section.
(2) Determine a well's final surface location, water depth, and the rotary kelly bushing elevation.	Immediately Submit a form MMS–124.	Submit a plat certified by a registered land surveyor that meets the requirements of § 250.412.
(3) Move a drilling unit from a wellbore before completing a well.	Submit forms Submit MMS–124 and MMS–125 within 30 days after the susepsion of wellbore operations.	Submit appropriate copies of the well recods.

(b) If you intend to perform any of the actions specified in paragraph (a)(1) of this section, you must meet the following additional requirements:

(1) Your form MMS–124 must contain a detailed statement of the proposed work that will materially change from the approved APD;

(2) Your form MMS–124 must include the present status of the well, depth of all casing strings set to date, well depth, present production zones and productive capability, and all other information specified; and

(3) Within 30 days after completing this work, you must submit form MMS–124 with detailed information about the work to the District Supervisor, unless you have already provided sufficient information in a Well Activity Report, form MMS–133 (§ 250.468(b)).

§ 250.466 What records must I keep?

You must keep complete, legible, and accurate records for each well. You must keep drilling records onsite while drilling activities continue. After completion of drilling activities, you must keep all drilling and other well records for the time periods shown in § 250.469. You may keep these records at a location of your choice. The records must contain complete information on all of the following:

(a) Well operations;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Supervisor in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.

§ 250.467 How long must I keep records?

You must keep records for the time periods shown in the following table.

You must keep records relating to	Until
(a) Drilling	Ninety days after you complete drilling operations.
(b) Casing and liner pressure tests, diverter tests, and BOP tests	Two years after the completion of drilling operations.
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you forward the records with a lease assignment.

§ 250.468 What well records am I required to submit?

(a) You must submit copies of logs or charts of electrical, radioactive, sonic, and other well-logging operations; directional and vertical-well surveys; velocity profiles and surveys; and analysis of cores to MMS. Each Region will provide specific instructions for submitting well logs and surveys.

(b) For drilling operations in the GOM OCS Region, you must submit form MMS–133, Well Activity Report, to the District Supervisor on a weekly basis.

(c) For drilling operations in the Pacific or Alaska OCS Regions, you must submit form MMS–133, Well Activity Report, to the District Supervisor on a daily basis.

§ 250.469 What other well records could I be required to submit?

The Regional or District Supervisor may require you to submit copies of any or all of the following well records.

(a) Well records as specified in § 250.466;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that prescribes the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

Hydrogren Sulfide

* * * * *

9. In the newly redesignated § 250.490, paragraphs (g)(4)(iv), (j)(13)(ii), and (p)(2) are revised to read as follows:

§ 250.490 Hydrogen sulfide.

* * * * *

(g) * * *

(4) * * *

(iv) Restrictions and corrective measures concerning beards, spectacles, and contact lenses in conformance with ANSI Z88.2, American National Standard for Respiratory Protection (incorporated by reference as specified in § 250.198);

* * * * *

(j) * * *

(13) * * *

(ii) Design, select, use, and maintain respirators in conformance with ANSI Z88.2 (incorporated by reference as specified in § 250.198).

* * * * *

(p) * * *

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H_2S-bearing fluids in conformance with NACE Standard MR0175–99 (incorporated by reference as specified in § 250.198).

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§ 250.504 [Amended]

10. In § 250.504, in the first and last sentences, the citation ''§ 250.417'' is revised to read ''§ 250.490''.

§ 250.513 [Amended]

11. In § 250.513, the following changes are made:

A. In paragraph (a), the citation ''§ 250.414'' is revised to read ''§ 250.410 through § 250.418''.

B. In paragraph (b)(4), the citation ''§ 250.417'' is revised to read ''§ 250.490''.

12. In § 250.515, paragraph (b) is revised to read as follows:

§ 250.515 Blowout prevention equipment.

* * * * *

(b) The minimum BOP system for well-completion operations 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 or 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 or 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 or blind-shear rams.
(4) You use a tapered drill string	At least one set of pipe rams that are capable of sealing around each size of drill string. 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. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) It is after February 21, 2006	At least one set of blind-shear rams. The blind-shear rams must be capable of shearing the drill pipe or tubing in the hole.

* * * * *

§ 250.604 [Amended]

13. In § 250.604, in the first and last sentences, the citation ''§ 250.417'' is revised to read ''§ 250.490''.

§ 250.613 [Amended]

14. In § 250.613(b)(3), the citation ''§ 250.417'' is revised to read ''§ 250.490''.

15. In § 250.615, paragraph (b) is revised to read as follows:

§ 250.615 Blowout prevention equipment.

* * * * *

(b) The minimum BOP system for well-workover 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 or 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 or 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 or blind-shear rams.
(4) You use a tapered drill string	At least one set of pipe rams that are capable of sealing around each size of drill string. 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. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) It is after February 21, 2006	At least one set of blind-shear rams. The blind-shear rams must be capable of shearing the drill pipe or tubing in the hole.

§ 250.807 [Amended]

16. In § 250.807, the citation ''§ 250.417'' is revised to read ''§ 250.490''.

§ 250.1105 [Amended]

17a. In § 250.1105(f)(1)(i), the citation ''§ 250.417(f)'' is revised to read ''§ 250.490(f)''.

§ 250.1604 [Amended]

17b. In § 250.1604 in paragraph (b), in the first and third sentences, the citation ''§ 250.417'' is revised to read ''§ 250.490''.

§ 250.1612 [Amended]

18. In § 250.1612, the citation ''§ 250.408'' is revised to read ''§ 250.462''.

§ 250.1614 [Amended]

19. In § 250.1614, in paragraph (b), the citation ''§ 250.410(b), (c), (d), and (e)'' is revised to read ''§ 250.455 through § 250.459''; and the citation ''§ 250.410(b)(8)'' is revised to read ''§ 250.456(g)''.

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