promulgated, will not have a significant economic impact, positive or negative, on a substantial number of small entities under the criteria of the Regulatory Flexibility Act. A copy of the draft regulatory evaluation prepared for this action is contained in the Rules Docket. A copy of it may be obtained by contacting the Rules Docket at the location provided under the caption **ADDRESSES**.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Safety.

The Proposed Amendment

Accordingly, pursuant to the authority delegated to me by the Administrator, the Federal Aviation Administration proposes to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding the following new airworthiness directive:

Boeing: Docket 98–NM–298–AD.

Applicability: Model 737, 757, and 767 series airplanes, certificated in any category, as listed in the following Boeing Alert Service Bulletins:

—737–29A1073, Revision 2, dated July 1, 1999 (for Model 737 series airplanes);
—757–29A0048, Revision 2, dated July 1, 1999 (for Model 757 series airplanes);
—767–29A0083, Revision 2, dated July 15, 1999 (for Model 767 series airplanes).

Note 1: This AD applies to each airplane identified in the preceding applicability provision, regardless of whether it has been modified, altered, or repaired in the area subject to the requirements of this AD. For airplanes that have been modified, altered, or repaired so that the performance of the requirements of this AD is affected, the owner/operator must request approval for an alternative method of compliance in accordance with paragraph (d) of this AD. The request should include an assessment of the effect of the modification, alteration, or repair on the unsafe condition addressed by this AD; and, if the unsafe condition has not been eliminated, the request should include specific proposed actions to address it.

Compliance: Required as indicated, unless accomplished previously.

To prevent failure of the motor operated hydraulic shutoff valves, which could result in leakage of hydraulic fluid to the engine fire zone, reduced ability to retract the landing gear, loss of backup electrical power or other combinations of failures, and consequent reduced controllability of the airplane, accomplish the following:

Repetitive Operational Checks/Corrective Action

(a) Within 6 months after the effective date of this AD: Perform an operational check to detect malfunctioning of any Circle Seal motor operated hydraulic shutoff valve having a part number specified in the ''Existing Part Number'' column (including parts marked with the suffix ''R'' after the serial number), of Paragraph 2.E. of Boeing Alert Service Bulletin 737–29A1073, Revision 2 (for Model 737 series airplanes), or 757–29A0048, Revision 2 (for Model 757 series airplanes), both dated July 1, 1999; or 767–29A0083, Revision 2, dated July 15, 1999 (for Model 767 series airplanes); as applicable; in accordance with the applicable alert service bulletin.

(1) If any malfunction of any valve is detected, prior to further flight, replace the valve with a new Whittaker valve in accordance with the applicable service bulletin. Repeat the operational check thereafter at intervals not to exceed 6 months until accomplishment of the terminating action required by paragraph (b) of this AD on all subject valves.

(2) If no malfunction of any valve is detected, repeat the operational check thereafter at intervals not to exceed 6 months until accomplishment of the terminating action required by paragraph (b) of this AD on all subject valves.

Terminating Action

(b) Within 3 years after the effective date of this AD, accomplish the replacement of any Circle Seal valve having a P/N specified in the ''Existing Part Number'' column (including parts marked with the suffix ''R'' after the serial number), of Paragraph 2.E. of Boeing Alert Service Bulletin 737–29A1073, Revision 2 (for Model 737 series airplanes); 757–29A0048, Revision 2 (for Model 757 series airplanes), both dated July 1, 1999; or 767–29A0083, Revision 2, dated July 15, 1999 (for Model 767 series airplanes); with a new Whittaker valve in accordance with the applicable alert service bulletin. Accomplishment of this replacement constitutes terminating action for the repetitive operational checks required by this AD.

Spares

(c) As of the effective date of this AD, no person shall install on any airplane, any part identified in the ''Existing Part Number'' column (including parts marked with the suffix ''R'' after the serial number), of Paragraph 2.E. of Boeing Alert Service Bulletin 737–29A1073, Revision 2 (for Model 737 series airplanes); 757–29A0048, Revision 2 (for Model 757 series airplanes), both dated July 1, 1999; or 767–29A0083, Revision 2, dated July 15, 1999 (for Model 767 series airplanes); as applicable.

Alternative Methods of Compliance

(d) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Seattle Aircraft Certification Office (ACO), FAA, Transport Airplane Directorate. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Seattle ACO.

Note 2: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Seattle ACO.

Special Flight Permits

(e) Special flight permits may be issued in accordance with sections 21.197 and 21.199 of the Federal Aviation Regulations (14 CFR 21.197 and 21.199) to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Renton, Washington, on June 15, 2000.

Donald L. Riggin,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 00–15661 Filed 6–20–00; 8:45 am]

BILLING CODE 4910–13–U

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: Proposed rule.

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

DATES: MMS will consider all comments we receive by September 19, 2000. We will begin reviewing comments then and may not fully consider comments we receive after September 19, 2000.

ADDRESSES: Mail or hand-carry comments to the Department of the Interior; Minerals Management Service; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817;

Attention: Rules Processing Team (Comments).

Mail or hand-carry comments with respect to the information collection burden of the proposed rule to the Office of Information and Regulatory Affairs; Office of Management and Budget; Attention: Desk Officer for the Department of the Interior (OMB control number 1010–NEW); 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Bill Hauser, Engineering and Operations Division, at (703) 787–1600.

SUPPLEMENTARY INFORMATION: This proposed revision of Subpart D, Oil and Gas Drilling Operations, contains several changes from the current regulations. One major change is the organization of the subpart. We have moved the Application for Permit to Drill (APD) section into the front of the subpart, where it becomes the cornerstone of the drilling requirements. The other sections follow in a logical sequence. The last major revision to the drilling regulations occurred on April 1, 1988 (53 FR 10596), when MMS consolidated the OCS Orders and the regulations into a single package. We welcome comments on the order of the sections.

The proposed rule uses several methods to put MMS's drilling requirements in plain language. These methods include:

- Breaking down lengthy sections into multiple sections;
- Using lists in place of lengthy paragraphs;
- Moving and consolidating similar requirements into single sections;
- Using tables where possible (such as casing and cementing requirements);
- Removing overly prescriptive requirements;
- Using ''you'' to refer to the lessee, operator, or person acting on behalf of a lessee; and
- Using questions as section titles.

We encourage your comments on any of these innovations.

The rule also proposes some new requirements. MMS District Supervisors and Drilling Engineers recommended most of the new proposed requirements based on their experience of reviewing and approving Applications for Permit to Drill and other drilling operations. Some of the new requirements will improve the flow of information between the lessee and the Drilling Engineer reviewing a request (such as listing all departures in one place as required in § 250.418(g)) or will fill a gap in the current regulations (such as recordkeeping for casing tests in § 250.428). The following paragraphs identify and briefly discuss the most important proposed revisions. We welcome your comments on these proposed requirements.

Rig Move Notification (§ 250.404)

The proposed rule would require the lessee to notify the District Supervisor 24 hours before rig arrival on and departure from the well location. MMS needs to know the comings and goings of drilling rigs to effectively and efficiently schedule inspections of drilling operations. MMS has attached this requirement as a condition of approval to APDs for many years. This would now make this condition of approval part of the regulations.

New Form To Supplement the APD Information (§ 250.410)

The proposed rule requires a lessee to use the new form MMS–123–Supplemental APD Information Sheet. The new form provides MMS drilling engineers with a technical summary of the information required in the APD. This aids District offices in the efficient review and approval of APDs. We also believe the successful use of this form helps pave the way for future electronic submissions of APDs.

The Office of Management and Budget has approved the new form, which does not require any new information. For further information about this form, you may contact Bill Hauser or Alexis London with the Rules Processing Team at 703–787–1600.

Well Location Description (§ 250.412)

The proposed rule requires the lessee to provide a more precise description of the surface and subsurface locations of the proposed well. The current regulations require lessees to provide the location in feet from the block line, but there has been a longstanding problem for computer routines that convert distances from block lines to x-y and longitude-latitude coordinates for well locations in irregular blocks. The x-y and longitude-latitude coordinates will be more accurate, allow easier data entry, and be more compatible for mapping.

Requests for Using Alternative Procedures or Departures from the Regulations (§ 250.418(g))

The proposed rule requires the lessee to list and discuss all requests for using alternative procedures or departures from the regulations in one place within the APD. This will aid District offices in the review and approval of these requests and the APD. The proposed rule requires you to explain how the alternative procedure affords an equal or greater degree of protection, safety, or performance or why you need the departure.

Waiting on Cement (§ 250.422(b))

The proposed rule requires that the lessee must determine when it is safe to nipple down (remove) the diverter or blowout preventer (BOP) stack after cementing a casing string. MMS proposes this new requirement because there have been some cases where a blowout occurred after a lessee nippled down the diverter or BOP stack while waiting on cement. We considered setting a specific waiting time or a compressive strength for the cement but decided that the complexity of cementing operations and variety of cements are not good candidates for a prescriptive requirement. The proposed rule makes the lessee responsible for evaluating the factors associated with each cement job to determine when it is safe to nipple down the diverter or BOP stack.

Currently, MMS requires the lessee to hold the cement in newly cemented casing strings under pressure for 8 hours for conductor casing or 12 hours for other casing strings before resuming drilling. It is during these waiting times that the lessees usually nipple down and nipple up (install) the diverter or BOP stack. The proposed rule does not revise or remove these waiting times. These required waiting times help ensure that the cement attains sufficient strength to safely resume drilling. Your comments on this approach to addressing this issue are welcomed.

Best Cementing Practices

The current drilling requirements do not address the methods you must use to cement casing strings. MMS has allowed lessees to use their judgment in selecting the proper method of cementing casing and liners. While this approach has worked for the successful drilling and completion of wells, we are less convinced that this approach has been successful for the long-term life of many wells. MMS believes that poor cementing practices are among the main primary causes of sustained casing pressures on producing wells. As a preventive measure to reduce the number of wells with sustained casing pressures, we recommend that lessees use better cementing practices for production wells. This is especially true with subsea wells where it is not possible to monitor most casing pressures. We welcome your comments on the use of improved cementing practices to address some of the problems associated with sustained casing pressures.

Minimum Cemented Casing Strings for Producing Wells (§ 250.423(f))

The proposed rule requires that you must have at least two cemented casing strings if you plan to produce the well. This has been an unwritten rule for OCS wells in the Gulf of Mexico Region (GOMR) for many years. MMS believes that two cemented casing strings (not including any cemented liners) are the minimum needed to ensure safe production for the life of the well. This proposed requirement makes this unwritten requirement available for comment.

Recordkeeping for Casing, Liner, and Diverter Pressure Tests (§§ 250.427 and 250.434)

The proposed rule clarifies what MMS has expected a lessee to record for casing, liner, and diverter pressure tests. The casing pressure test must be recorded on a pressure chart and certified by your onsite representative as being correct. The time, date, and results are then recorded in the driller's report. Recordkeeping requirements for a diverter test are similar to those required for a BOP test.

Blind-shear Ram for Surface BOP Systems (§§ 250.441, 250.515(b), and 250.615(b))

The proposed rule requires a lessee to install a blind-shear ram in the surface BOP stack instead of a blind ram. MMS believes that a blind-shear ram in the surface stack provides an additional safety measure in handling well control events. We recently reviewed the blowouts that have occurred since 1977 and found at least 12 incidents where a blind-shear ram had helped or could have helped control the situation. These blowouts usually occurred when drill pipe or tubing was hung in the BOP stack, and there were difficulties in installing or closing a drill string safety valve, inside the BOP, or tubing safety valve. Several of these blowout events had major casualties and/or damage to platforms and drilling rigs.

MMS believes that the use of blind-shears rams will prevent or minimize some blowouts on the OCS. This would reduce the risk of injury and loss of life to personnel and the risk of environmental damages from a blowout. We believe the benefits from reduced injuries, fatalities, environmental damages, and losses from property damages will easily out weigh the costs of installing the blind-shear rams. This measure is consistent with our Congressional mandate to prevent or minimize the likelihood of blowouts (OCS Lands Act at 43 U.S.C. 1332(6)).

MMS believes that the installation of a blind-shear ram in BOP stacks should also be applied to completion and workover operations because several of the above blowout events involved completions and workovers. The proposed rule does not apply to workovers with the tree in place. The proposed rule also revises § 250.515(b) and § 250.615(b).

The proposed rule provides for a 1-year grace period to comply with the requirement to install a blind-shear ram on surface stacks. Lessees will have 1 year from the effective date of the final rule to install blind-shear rams in all surface BOP stacks.

Reference Minimum Accumulator Requirements for Subsea BOP Systems (§ 250.442)

The proposed rule references section 12.3, Accumulator Volumetric Capacity, in the American Petroleum Institute's Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells (API RP 53). We included this reference so that both industry and MMS would have guidelines for determining the minimum requirements and performance for subsea accumulators and BOP systems. Included in this section are minimum accumulator response times for annular and ram preventers. The proposed rule also requires the lessee to record the closing times for subsea annular and ram preventers. These proposed revisions will help ensure that subsea BOP systems operate at proper levels of performance.

Reference Minimum BOP Maintenance Requirements (§ 250.446)

The current regulations in § 250.407 require the lessee to maintain BOP equipment to ensure that it operates properly. The proposed rule goes on to require that this 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), in API RP 53. MMS selected API RP 53 as the standard to use because it represents a composite of the practices used by various operators and drilling contractors.

The importance of a thorough maintenance program is even greater now that MMS has allowed lessees to test BOP equipment less frequently than before (see final rule for BOP testing published June 1, 1998, 63 FR 29604). MMS believes that maintenance is critical to the proper operation of BOP equipment. MMS considered including specific maintenance practices when we revised the BOP testing requirements but decided to limit that rulemaking to the BOP testing issue since the BOP performance study did not specifically address BOP maintenance. This rulemaking would set those minimum requirements.

The proposed rule references only specific sections of API RP 53. We have referenced specific sections because these were the most critical areas of concern. However, several industry commenters on the BOP testing requirements recommended incorporating the entire API RP 53 document. We would like your comments on whether MMS should reference specific sections or incorporate the entire document into the regulations.

Use of Maximum Anticipated Surface Pressure (MASP) for Determining BOP Test Pressures (§ 250.448)

As discussed in the preambles of the proposed (July 15, 1997, 62 FR 37819) and final rules for BOP testing requirements, MMS has considered using MASP in determining BOP test pressures. Industry comments on the proposed BOP testing rule showed interest in this approach for determining test pressures, but both industry and MMS expressed concerns about how to calculate MASP. After considerable thought, MMS has decided to propose using MASP calculations in determining BOP test pressures. Under the proposed rule, the high pressure test must either equal the rated working pressure of the equipment, or be 500 pounds per square inch (psi) greater than the calculated MASP for the applicable section of hole, whichever is smaller. This reflects how MMS currently reviews and approves test pressures. It is also consistent with current industry practice of testing BOPs at less than the rated working pressures. The proposed rule also clearly states that the District Supervisor must have approved the MASP plus 500 psi test pressures in the APD.

Currently, District Supervisors base the approval of alternate test pressures on a comparison of the anticipated surface pressure calculations submitted with the APD to MASP calculations made by MMS drilling engineers. If the two calculations compare favorably, the District Supervisor approves the requested test pressures. If the calculations for anticipated surface pressure are less than those calculated by MMS, the District Supervisor advises the lessee of any necessary revisions to the APD.

Change in Terminology—Mud to Drilling Fluid

The proposed rule changes the term ''mud'' as in drilling mud to ''drilling fluid.'' We believe that this change more accurately reflects the current terminology. We have changed the term ''mud'' to ''drilling fluid'' throughout subpart D. We will make the same change in other subparts as we revise them.

Posting Maximum Safe Pressures Contained Under a Shut-In BOP (§ 250.456(f))

The proposed rule clarifies the current requirement of posting the maximum pressure that you may safely contain under a shut-in BOP for each casing string. The proposed rule requires the posting of two pressures: (1) the surface pressure at which the casing shoe would break down and, (2) the lesser of the BOP's rated working pressure or 70 percent of casing burst pressure (or casing test pressure otherwise approved by the District Supervisor). The current requirement has led to some confusion as to what safe pressure MMS wants posted, i.e., formation fracture pressure or equipment limitation pressure. By having both pressures posted, the driller will have additional information immediately available for decisionmaking.

Establish Well Testing Requirements (§ 250.460)

The proposed rule establishes minimum requirements for well-testing activities. Currently there are no regulations that specifically address well testing. MMS believes that minimum requirements are necessary to understand and evaluate the lessee's anticipated well-testing activities. The proposed rule would require a lessee to submit information about testing procedures and equipment to the District Supervisor for approval with the APD or a Sundry Notice. You would not be allowed to conduct the well test until the District Supervisor approves the submitted test information. The information that must be submitted includes estimated flowing and shut-in tubing pressures; estimated flow rates and cumulative volumes; time duration of flow, buildup, and drawdown periods; a description of surface and subsurface test equipment; proposed methods to handle or transport produced fluids; and a full description of the test procedures.

Simplify Survey Requirements for Directional Drilling (§ 250.461)

The proposed rule simplifies the language and the requirements to be consistent with current practices and technology. The proposed rule also makes these survey requirements a separate section.

Hydrogen Sulfide (§ 250.470)

The hydrogen sulfide section of subpart D was not revised. We are not revising this section now because it was revised in January 1997 (62 FR 3795). MMS will consider revising this section as we begin the rewriting of subpart E, Oil and Gas Well-Completion Operations; subpart F, Oil and Gas Well-Workover Operations; and subpart H, Oil and Gas Production Safety Systems. Your comments on the best method to rewrite or reorganize the hydrogen sulfide requirements are welcomed.

Requirements Removed From Subpart D

The proposed rule does not contain requirements for the welding and burning practices and procedures (former § 250.402) or electrical equipment (former § 250.403). These requirements were moved to subpart A of the regulations in the Notice of Final Rulemaking for subpart A, which was published in the **Federal Register** on December 28, 1999 (64 FR 72756).

The proposed rule also removes the detailed well-control drill requirements. These requirements (current § 250.408) prescribe how the lessee is to conduct the drill. MMS proposes to remove these requirements because they are too prescriptive. MMS still would require the lessee to outline the assignments for each member of the drilling crew.

Other Considerations for Drilling Regulations

MMS also considered including regulations for drilling with coiled tubing units in this revision of subpart D. However, we decided to postpone proposing requirements for coiled tubing drilling operations until MMS has a better understanding of these operations and the amount of activity that will likely take place on the OCS. MMS would most likely use API's Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services (API RP 5C7) as a guideline when we do propose appropriate regulations. We would like your comments on the need for regulations for coiled tubing drilling.

MMS is also looking at requiring drilling rigs to use automated pipe handling systems during drilling operations. MMS believes that the use of automated pipe handling systems clearly provides safety advantages over non-automated pipe handling systems. After further consultation with the U.S. Coast Guard, we may propose this new requirement under the provision in § 250.107, which mandates that the Director require the use of the best available and safest technology to protect health, safety, property, and environment. We welcome your comments on requiring automated pipe handling systems as well as your comments on the best approach to implementing this requirement.

Derivation Table

The derivation table below shows where the proposed requirements come from in relation to the current sections. The table also provides the section numbers that were used from 1988 up until mid-1998 when MMS assigned new numbers to the sections to aid in the updating and revision of the regulations (63 FR 29478, May 29, 1998).

DERIVATION TABLE

Proposed new section and title	Current section	Previous numbering system
250.400 Who is subject to the requirements of this subpart?	New section	New section.
250.401 What must I do to keep wells under control?	250.400	250.50.
250.402 When and how must I secure a well?	250.411	250.61.
250.403 What safety requirements must my drilling unit meet?	250.401	250.51.
250.404 What mobile drilling unit movements must I report?	New requirement	New requirement.
250.410 How can I apply for a permit to drill a well?	250.414(a)	250.64(a).
250.411 What material must I submit with my application?	?250.414(f)	250.64(f).
250.412 What requirements must my plat meet?	?250.414(f)(1)	250.64(f)(1).
250.413 What items must my description of well drilling design criteria address?	250.414(f)(2)	250.64(f)(2).

DERIVATION TABLE—Continued

Proposed new section and title	Current section	Previous numbering system
250.414 What items must my drilling prognosis include?	250.414(f)(5)	250.64(f)(5).
250.415 What items must my casing and cementing programs include?	250.414(f)(4 and 6)	250.64(f)(4 and 6).
250.416 What information must be included in the diverter and BOP descriptions?	250.414(f)(3)	250.64(f)(3).
250.417 What information must I provide if I intend to use a mobile drilling unit to drill a proposed well?	250.414(b)	250.64(b).
250.418 What additional requirements must I meet?	250.414(f)(11)	250.64(f)(11).
250.420 What well casing and cementing requirements must I meet?	250.404(a)(1) 250.404(a)(2)	250.54(a)(1) 250.54(a)(2).
250.421 What are the casing and cementing requirements by type of casing string?	250.404(b),(c),(d), and (e)	250.54(b),(c), (d), and (e).
250.422 When may I resume drilling after cementing?	250.405(d)	250.55(d).
250.423 How must I remedy cementing and casing problems and situations?	250.404 and .405	250.54 and .55.
250.424 What are the requirements for pressure testing casing?	250.405	250.55.
250.425 What special pressure tests must I perform on casings for prolonged drilling operations?	250.405	250.55.
250.426 What are the requirements for pressure testing liners?	250.405	250.55.
250.427 What are the recordkeeping requirements for casing and liner pressure tests?	250.405(a) and New requirement	250.55(a).
250.428 What are the requirements for pressure integrity tests?	250.404(a)(6)	250.54(a)(6).
250.430 When must I install a diverter system?	250.409(a)	250.59(a).
250.431 What are the diverter design and installation requirements?	250.409(c)	250.59(c).
250.432 What must I do to obtain a departure to diverter design and installation requirements?	250.409(d)	250.59(d).
250.433 How must I test the diverter system after installation?	250.409(f)	250.59(f).
250.434 What are the recordkeeping requirements for diverter tests?	250.409(f)	250.59(f).
250.440 What are the general requirements for BOP systems and system components?	250.406(a) and (b)	250.56(a) and (b).
250.441 What are the requirements for a surface BOP stack?	250.406(f)	250.56(f).
250.442 What are the requirements for a subsea BOP stack?	250.406(e)	250.56(e).
250.443 What associated BOP systems and related equipment must my BOP system include?	250.406(d)	250.56(d).
250.444 What are the choke manifold requirements?	250.406(d)(7)	250.56(d)(7).
250.445 What are the requirements for kelly cocks, inside BOPs, and drill-string safety valves?	250.406(d)(10)	250.56(d)(10).
250.446 What must I do to maintain and inspect my BOP?	250.407(f) and (g)	250.57(f) and (g).
250.447 When must I conduct BOP system pressure tests?	250.407(a)	250.57(a).
250.448 What are the BOP pressure tests requirements?	250.407(b) and (c)	250.57(b) and (c).
250.449 Are there additional BOP testing requirements with which I must comply?	250.407(d)	250.57(d).
250.450 What are the recordkeeping requirements for BOP tests?	250.407(h)	250.57(h).
250.451 How do I remedy BOP problems and situations?	250.407(c), (d) and (e)	250.57(c), (d) and (e).
250.455 What are the general requirements for a drilling fluid program?	250.410(a)	250.60(a).
250.456 What are the required safe drilling fluid program practices?	250.410(b)	250.60(b).
250.457 What equipment must I have to test and monitor drilling fluids?	250.410(c)	250.60(c).
250.458 What quantities of drilling fluids are required?	250.410(d)	250.60(d).
250.459 What are the safety requirements for drilling fluid-handling areas?	250.410(e)	250.60(e).
250.460 What are the requirements for well testing?	250.401(e)(1) and new requirement for well testing.	250.51(e)(1).
250.461 What are the requirements for directional and inclination surveys?	250.401(e)(2),(3), and (4)	250.51(e)(2),(3), and (4).
250.462 What are the requirements for well-control drills?	250.408	250.58.
250.463 Who establishes field drilling rules?	250.412	250.62.
250.465 When must I submit forms to MMS?	250.415	250.65.
250.466 What well records must I keep?	250.416(a)	250.66(a).
250.467 What well records may I be required to submit?	250.416(c)	250.66(c).
250.468 How long must I keep drilling-related records?	250.416(a) and (g)	250.66(a) and (g).
250.469 Must I submit copies of well logs?	250.416(d)	250.66(d).
250.470 Hydrogen sulfide	250.417	250.67.

Procedural Matters

Public Comments Procedures

Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their home address from the rulemaking record, which we will honor to the extent allowable by law. There may be circumstances in which we would withhold from the rulemaking record a respondent's identity, as allowable by the law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

Takings Implication Assessment (Executive Order (E.O.) 12630)

According to E.O. 12630, the proposed rule does not have significant Takings Implications. A Takings Implication Assessment is not required. The proposed 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 pursuant to E.O. 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

Regulatory Planning and Review (E.O. 12866)

This proposed rule is a significant rule under E.O. 12866; therefore, OMB will review the proposed rule.

(1) This proposed 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 for this proposed 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 proposed technical revisions will have a minor economic effect on lessees and drilling contractors. The cost of the rule is affected by the response of existing and future potential regulated entities to anticipated prices and returns in the energy markets. With increases in the prices of oil and natural gas, the amount of drilling activity and affected entities could increase as could the estimated cost of the proposed rule. However, even with such changes, MMS believes the rule will not have an annual effect on the economy of $100 million. Specifically, given the existing industry structure (i.e., the number and size of affected regulated entities remains constant), MMS estimates the first year cost to implement the rule at less than $15 million. Over 95 percent of the estimated cost of the proposed rule is due to the acquisition and installation of the blind-shear rams. The recurring costs in the ensuing years, given no change to the existing structure of the OCS lessees and drilling contractors, are estimated at $1 million annually.

The majority of the cost to implement the proposed rule is due to the required installation of blind-shear rams ($14 million) in a surface BOP stack. 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 proposed 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 estimates that installation of a blind-shear ram in the BOP stack could prevent or minimize one blowout every 2 years. This estimate comes from the 12 incidents that MMS identified where a blind-shear ram had helped or could have helped prevent or minimize a blowout over a 23+ year period (1977 to present). Considering that a single blowout could cause multiple injuries, fatalities, and tens of millions of dollars in property damage and financial losses, MMS believes that the benefits of this proposed requirement will more than offset the cost of this proposed requirement.

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

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

(4) This proposed rule does not raise novel legal or policy issues. The proposed rule involves some new policy issues, such as requiring minimum BOP maintenance requirements and blind-shear rams for surface BOP stacks, but these new policy decisions are not ''novel.'' They simply address recognized gaps in our safety regulations. These minimum requirements are generally accepted practices that are included in API documents.

Civil Justice Reform (E.O. 12988)

According to E.O. 12988, the Office of the Solicitor has determined that this proposed 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 proposed rule does not constitute a major Federal action significantly affecting the quality of the human environment. An environmental assessment is not required.

Paperwork Reduction Act (PRA) of 1995

The proposed rule contains a collection of information that has been submitted to OMB for review and approval under § 3507(d) of the PRA. As part of our continuing effort to reduce paperwork and respondent burdens, MMS invites the public and other Federal agencies to comment on any aspect of the reporting and recordkeeping burden. Submit your comments to the Office of Information and Regulatory Affairs; OMB; Attention: Desk Officer for the Department of the Interior (OMB control number 1010–NEW); 725 17th Street, NW, Washington, DC 20503. Send a copy of your comments to the Rules Processing Team, Attn: Comments; Mail Stop 4024; Minerals Management Service; 381 Elden Street; Herndon, Virginia 20170–4817. You may obtain a copy of the supporting statement for the new collection of information by contacting the Bureau's Information Collection Clearance Officer at (202) 208–7744.

The PRA provides that an agency may not conduct or sponsor and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. OMB is required to make a decision concerning the collection of information contained in these proposed regulations between 30 to 60 days after publication of this document in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by July 21, 2000. This does not affect the deadline for the public to comment to MMS on the proposed regulations.

The title of the collection of information for this proposed rule is ''Proposed Rulemaking—30 CFR 250, Subpart D—Oil and Gas Drilling Operations'' (OMB control number 1010–NEW). Respondents include approximately 130 Federal OCS oil and gas or sulphur lessees. The frequency of response is on occasion, daily, weekly, quarterly, or annually depending upon the requirement. Responses to this collection of information 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 collection of information required by the current subpart D regulations is approved by OMB under control number 1010–0053. The proposed rule imposes very few changes to the information collection burden. The major changes are:

• Notification of drilling rig movement on or off drilling location (+100 burden hours);

• Incorporation of two new forms (Supplemental APD Information Sheet and Weekly Activity Report) separately approved under 1010–0131 and 1010–0132; and

• Submission of well testing plans (+30 burden hours).

We estimate the total annual reporting and recordkeeping ''hour'' burden for the proposed rule to be 107,866 hours representing an average burden of 830 hours per respondent. Except for the items identified as ''new'' in the following chart, the burden estimates shown are those that are estimated for the current subpart D regulations. The public has had numerous opportunities to comment on the estimates during the process to renew the OMB approval of the information collection requirements in current regulations. We have also consulted with a representative sampling of respondents to verify these estimates.

BURDEN BREAKDOWN

Citation 30 CFR 250 Subpart D	Reporting requirement	Frequency	Number	Burden	Annual burden
402 [Current 411]	Request approval to use blind or blind-shear ram or pipe rams and inside BOP.	On occasion	6 requests	10 minutes	1
403(c), 404 [New]	Notify MMS of drilling rig movement on or off drilling location.	On occasion	1,000 notifications	6 minutes	100
403(c) [Current 401]	Request approval not to shut-in well during equipment movement.	On occasion	10 requests	1 hour	10
410–418, plus various references throughout subpart D*.	APD to drill, including various approvals required in subpart D and obtained via forms MMS–123 and MMS–123S, and supporting information. [*All current requirements in various sections.].	Burden covered under 1010–0044 (form MMS–123, APD); 1010–0131 (new collection form MMS–123S, Supplemental APD Information Sheet).			0
410(c), 417(b) [Current 405].	Exploration Plan, Development and Production Plan, Development Operations Coordination Document.	Burden covered under 1010–0049 (30 CFR 250, Subpart B)			0
417(c) [Current 401]	Submit 3rd party review of drilling unit	Burden covered under 1010–0958 (30 CFR 250, Subpart I)			0
418(e) [Current 402]	Submit welding and burning plan	Burden covered under 1010–0114 (30 CFR 250, Subpart A)			0
423 [Current 404/405]	Submit revised casing and cementing program or changes.	On occasion	20% of 990 drilling ops. = 198.	2 hours	396
425 [Current 405]	Caliper, pressure test, or evaluate casing; submit evaluation results; request approval before resuming operations or beginning repairs.	Every 30 days during pro longed drilling;	20% of 990 wells = 198.	5 hours	990
456(c), (f) [Current 410].	Perform various calculations; post information.	On occasion, daily, weekly.	144 drilling rigs × 52 = 7,488.	.25 hour	1,872
459(a)(3) [Current 410].	Request exception to procedure for protecting negative pressure area.	On occasion	5 requests	2 hours	10
460(b), (c) [New; Current 401].	Submit plans for well testing and notify MMS before test.	On occasion	15 plans	2 hours	30
461(e) [Adjustment to current 401].	Provide copy of well directional survey to affected leaseholder.	On occasion	10 occasions	1 hour	10
462(a) [Current 408]	Prepare and post well control drill plan for crew members.	On occasion	26 plans	3 hours	78
463(b) [Current 412]	Request field drilling rules be established, amended, or canceled.	On occasion	6 requests	2.7 hours	[1] 16
465, 467 [Current 415/416].	Submit revised plans, changes, well/drilling records, etc., on forms MMS–124 or MMS–125.	Burden covered under 1010–0045 (form MMS–124, Sundry Notices and Reports); 1010–0046 (form MMS–125, Well Summary Report)			0
465(a), (b), (3); 467(c) [New].	In the GOMR, submit drilling activity on form MMS–133 on weekly basis.	Burden included under 1010–0132 (new form MMS–133) (Weekly Activity Report)			0
465(a); 467 [Current 416].	Submit well records, daily drilling report and other data as requested or specified by regional office.	On occasion, daily	20% of 990 wells = 198.	3 hours	594
469 [Current 416]	Submit well logs and survey results	On occasion	990 wells	1.5 hours	1,485
470(c)(4), (d) [Current 417].	Submit request for reclassification of H_2S zone; notify MMS if conditions change.	On occasion	27 responses	1.7 hours	[1] 46
470(f) [Current 417]	Submit contingency plans for operations in H_2S areas.	On occasion	27 plans (16 drill, 5 workover, 6 prod.).	10 hours	270
470(i) [Current 417]	Display warning signs	Not applicable: facilities would display warning signs and use other visual and audible systems			0
470(j)(12) [Current 417].	Propose alternatives to minimize or eliminate SO_2 hazards.	Proposals would be submitted with contingency plans; burden included in 250.470(f)			0
470(j)(13)(vi) [Current 417].	Label breathing air bottles	Not applicable: supplier normally labels bottles; facilities would routinely label if not			0
470(l) [Current 417]	Notify (phone) MMS of unplanned H_2S releases.	On occasion (apprx. 2/year).	49 facilities × 2 = 98	.2 hour	[1] 20

BURDEN BREAKDOWN—Continued

Citation 30 CFR 250 Subpart D	Reporting requirement	Frequency	Number	Burden	Annual burden
470(o)(5) [Current 417].	Request approval to use drill pipe for well testing.	On occasion	3 requests	2 hours	6
470(q)(1) [Current 417].	Seal and mark for the presence of H_2S cores to be transported.	Not applicable: facilities would mark transported cores			0
470(q)(9) [Current 417].	Request approval to use gas containing H_2S for instrument gas.	On occasion	3 requests	2 hours	6
470(q)(12) [Current 417].	Analyze produced water disposed of for H_2S content and submit results to MMS.	On occasion (apprx. weekly).	4 prod. platforms × 52 = 208.	2.8 hours	[1] 582
Total Reporting:			10,516		6,522

[1] Rounded.

Citation 30 CFR 250 Subpart D	Recordkeeping requirement	Frequency	Number	Burden	Annual burden
403 [Current 401]	Perform operational check of crown block safety device; record results.	Weekly (52)	144 drilling rigs × 52 = 7,488.	.1 hour	[1] 749
427 [Current 405]	Perform pressure test on all casing strings and drilling liner lap; record results.	On occasion	144 drilling rigs × apprx. 50 per rig = 7,200.	2 hours	14,400
428(a) [Current 404]	Perform pressure-integrity tests and related hole-behavior observations; record results.	On occasion	425 tests	4 hours	1,700
434 [Current 409]	Perform diverter tests when installed and once every 7 days; actuate system at least once every 24-hour period; record results; retain records 2 years after drilling completed.	On occasion (average 2 per drilling op).	990 drilling operations × 2 = 1,980.	2 hours	3,960
450 [Current 407]	Perform BOP pressure tests, actuations and inspections; record results; retain records 2 years following completion of drilling activity.	When installed; at a minimum every 14 days; as stated for components.	144 drilling rigs × apprx. 35 per rig = 5,040.	6 hours	30,240
450 [Current 407]	Function test annulars and rams; document results (Note: this test is part of BOP test when BOP test is conducted.).	Every 7 days between BOP tests (biweekly).	144 drilling rigs × appx. 20 per rig = 2,880.	.16 hour	461
451(c) [Current 407]	Record reason for postponing BOP test	On occasion (apprx. 2/year).	144 drilling rigs × 2 = 288.	.1 hour	[1] 29
456(b); 457(a), 458(b) [Current 410].	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.	144 drilling rigs × 52 = 7,488.	1.25 hours	9,360
462(c) [Current 408]	Perform well-control drills; record results	On occasion (2 crews × 52=102).	144 drilling rigs × 102 = 14,688.	1 hour	14,688
466, 468 [Current 416]	Retain drilling records for 90 days after drilling complete; retain casing/liner pressure, diverter, and BOP records for 2 years; retain well completion/well workover until well is permanently plugged/abandoned or lease assigned.	Annual records maintenance.	990 wells	1.5 hours	1,485
470(g)(2), (g)(5) [Current 417].	Conduct H_2S training; post safety instructions; document training.	On occasion; annual refresher (apprx. 2/year).	49 facilities × 2 = 98	2 hours	196
470(h)(2) [Current 417].	Conduct drills and safety meetings; document attendance.	Weekly (52)	49 facilities × 52 = 2,548.	1 hour	2,548
470(j)(8) [Current 417]	Test H_2S detection and monitoring sensors during drilling; record testing and calibrations (apprx. 12 sensors per rig).	On occasion (daily during drilling).	26 drilling rigs × 365 days = 9,490.	2 hours	18,980
470(j)(8) [Current 417]	Test H_2S detection and monitoring sensors during production; record testing and calibrations (apprx. 30 sensors on 5 platforms + apprx. 42 sensors on 23 platforms).	14 days	28 prod. platforms × 26 weeks = 728.	3.5 hours	2,548
Total Recordkeeping:					101,344

[1] Rounded.

Total Reporting	=	6,522
Total Recordkeeping	=	101,344
Total Burden	=	107,866

1. MMS specifically solicits comments on the following questions:

(a) Is the proposed collection of information necessary for MMS to properly perform its functions, and will it be useful?

(b) Are the estimates of the burden hours of the proposed collection reasonable?

(c) Do you have any suggestions that would enhance the quality, clarity, or usefulness of the information to be collected?

(d) Is there a way to minimize the information collection burden on those who are to respond, including the use of appropriate automated electronic, mechanical, or other forms of information technology?

2. In addition, the PRA requires agencies to estimate the total annual reporting and recordkeeping ''non-hour cost'' burden resulting from the collection of information. We have not identified any, and we solicit your comments on this item. For reporting and recordkeeping only, your response should split the cost estimate into two components: (a) Total capital and start-up cost component and (b) annual operation, maintenance, and purchase of services component. Your estimates should consider the costs to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Capital and start-up costs include, among other items, computers and software you purchase to prepare for collecting information; monitoring, sampling, drilling, and testing equipment; and record storage facilities. Generally, your estimates should not include equipment or services purchased: (1) Before October 1, 1995; (2) to comply with requirements not associated with the information collection; (3) for reasons other than to provide information or keep records for the Government; or (4) as part of customary and usual business or private practices.

Regulatory Flexibility (RF) Act

The Department of the Interior (DOI) certifies that this proposed 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 proposed rule applies to all lessees and drilling contractors that operate on the OCS. Small lessees and drilling contractors that operate under this proposed rule would fall under the Small Business Administration's (SBA) Standard Industrial Classification (SIC) codes 1311 Crude Petroleum and Natural Gas and 1381 Drilling Oil and Gas Wells. Under these SIC codes, SBA considers all companies with fewer than 500 employees to be a small business. Given the variability in the industry to changes in the relative prices of oil and natural gas, the numbers of small entities affected by the proposed 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 20 drilling contractors operate on the OCS, and that only one of those drilling contractors is 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.

New compliance costs associated with this proposed rule fall within two categories—of meeting new drilling requirements and the cost of purchasing additional blind shear rams. 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. The cost of the blind shear rams will be borne by drilling contractors.

We estimate that the total annual cost of the new drilling requirements proposed 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 107,866 hours as indicated in the Paperwork Reduction Act of 1995 (PRA) section of this preamble. However, the new burden that would be added by this proposed rule is only 140 hours (§ 250.403(c)—100 hours; § 250.460(b), (c)—30 hours; and § 250.461(e)—10 hours) as shown in the reporting and recordkeeping burden tables in the PRA section.

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 proposed revisions to the regulations will not have a significant economic effect on any small lessee. However, we do invite comment on our analytical procedures, data inputs, and findings.

The estimated economic effects 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 1999, the cost for a set of 10,000 pounds per-square-inch rams and associated equipment is about $175,000. 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 $175,000.

We estimate that drilling contractors will need to purchase a total of 80 blind shear rams to meet the proposed requirements. At an average cost of about $175,000, the economic impact will be $14,000,000. The largest drilling contractor may need to purchase up to 20 sets of blind-shear rams, while the one small drilling contractor will not need to purchase any blind-shear rams because the contractor already has blind-shear rams for its rigs. 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 proposed rule provides for a 1-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. In addition, several drilling contractors likely have one or more sets of blind-shear rams, because some lessees currently require the installation of these rams for their wells. Also, some contractors may choose not to outfit all of their rigs with blind-shear rams immediately. Those contractors may continue to market those rigs in State or international waters where blind-shear rams are not required.

The cost of blind-shear rams probably will affect the rates that drilling contractors charge lessees and operators to drill wells. Contractors base these rates, called day rates, primarily on the supply and demand of drilling rigs. We estimate that a minor increase in day rates (estimated at between $250 and $750 depending on rig capability and ram size) would increase the costs of drilling a typical OCS well by less than 1 percent. The minor increase in day rates to pay for the blind-shear rams should not last more than 3 years (the estimated time to pay for the rams). Since drilling contractors will have 1 year from the date of the final rule to purchase this equipment, they should have sufficient time to plan their purchase and adjust their day rates to reflect this cost. MMS believes the purchase of this equipment or any adjustments in day rates are unlikely to affect the competition between large and small drilling contractors.

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

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

As discussed above, 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. MMS asks for comments on the expected duration of the anticipated costs and the finding that the impacts on small drilling contractors are not significant.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses 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 enforcement actions of MMS, call toll-free (888) 734–3247.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

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

(a) Does not have an annual effect on the economy of $100 million or more. As described above, we estimate that the initial one-time cost of the proposed rule to be $14 million and $672,000 in subsequent years. These costs will not cause an annual effect on the economy of $100 million.

(b) Will not cause a major increase in costs or prices or 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.

(c) Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or ability of U.S.-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 U.S.-based enterprises to compete with foreign-based enterprises.

Unfunded Mandates Reform Act (UMRA) of 1995 (E.O. 12866)

This proposed 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 proposed rule does not have any Federal mandates nor does the proposed 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.

Federalism (E.O. 13132)

According to E.O. 13132, this rule does not have Federalism implications. This proposed 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.

Clarity of This Regulation

E.O. 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this proposed rule easier to understand, including answers to questions such as the following:

(1) Are the requirements in the proposed rule clearly stated?

(2) Does the proposed rule contain technical language or jargon that interfere with its clarity?

(3) Does the format of the proposed rule (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity?

(4) Would the proposed rule be easier to understand if it were divided into more (but shorter) sections?

(5) Is the description of the proposed rule in the ''Supplementary Information'' section of this preamble helpful in understanding the proposed rule? What else can we do to make the proposed rule easier to understand?

Send a copy of any comments that concern how we could make this proposed rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street, NW, Washington, DC 20240. You may also e-mail the comments to this address: Exsec@ios.doi.gov

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: February 11, 2000.

Sylvia V. Baca,

Acting Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the MMS proposes to amend 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 § 250.198, 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 entry for API RP 500 as set forth below.

§ 250.198 Documents incorporated by reference.

* * * * *

(e) * * *

Title of documents	Incorporated by reference at
* * * * *	* *
API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997, API Stock No. G53003	§ 250.442(b); § 250.446(a).
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, First Edition, June 1, 1991, API Stock No. G06005	§ 250.459; § 250.802(e)(4)(I); § 250.803(b)(9)(I); § 250.1628(b)(3); (d)(4)(I); § 250.1629(b)(4)(I).
* * * * *	* *

3. In 30 CFR part 250, subpart D, § 250.417 is redesignated as § 250.470, §§ 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 §§ 250.470 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

Sec.

250.400 Who is subject to the requirements of this subpart?
250.401 What must I do to keep wells under control?
250.402 When and how must I secure a well?
250.403 What safety requirements must my drilling unit meet?
250.404 What mobile drilling unit movements must I report?

Application for Permit To Drill Requirements

250.410 How can I apply for a permit to drill a well?
250.411 What material must I submit with my application?
250.412 What requirements must my plat meet?
250.413 What items must my description of well drilling design criteria address?
250.414 What items must my drilling prognosis include?
250.415 What items must my casing and cementing programs include?
250.416 What information must be included in the diverter and BOP descriptions?
250.417 What information must I provide if I intend to use a mobile drilling unit to drill a proposed rule?
250.418 What additional requirements must I meet?

Casing and Cementing Requirements

250.420 What well casing and cementing requirements must I meet?
250.421 What are the casing and cementing requirements by type of casing string?
250.422 When may I resume drilling after cementing?
250.423 How must I remedy cementing and casing problems and situations?
250.424 What are the requirements for pressure testing casing?
250.425 What special pressure tests must I perform on casings for prolonged drilling operations?
250.426 What are the requirements for pressure testing liners?
250.427 What are the recordkeeping requirements for casing and liner pressure tests?
250.428 What are the requirements for pressure integrity tests?

Diverter System Requirements

250.430 When must I install a diverter system?
250.431 What are the diverter design and installation requirements?
250.432 What must I do to obtain a departure to diverter design and installation requirements?
250.433 How must I test the diverter system after installation?
250.434 What are the recordkeeping requirements for diverter tests?

Blowout Preventer (BOP) System Requirements

250.440 What are the general requirements for BOP systems and system components?
250.441 What are the requirements for a surface BOP stack?
250.442 What are the requirements for a subsea BOP stack?
250.443 What associated BOP systems and related equipment must my BOP system include?
250.444 What are the choke manifold requirements?
250.445 What are the requirements for kelly cocks, inside BOPs, and drill-string safety valves?
250.446 What must I do to maintain and inspect my BOP?
250.447 When must I conduct BOP system pressure tests?
250.448 What are the BOP pressure tests requirements?
250.449 What additional BOP testing requirements must I comply with?
250.450 What are the recordkeeping requirements for BOP tests?

250.451 How do I remedy BOP problems and situations?

Drilling Fluid Requirements

250.455 What are the general requirements for a drilling fluid program?
250.456 What are the required safe drilling fluid program practices?
250.457 What equipment must I have to test and monitor drilling fluids?
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Hydrogen Sulfide

250.470 Hydrogen sulfide.

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, 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 that represents your interests and can fulfill your responsibilities;

(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, unless you have secured the well with blowout preventers (BOPs) 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 as deep as possible within a properly cemented casing string.

(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 a blind or blind-shear ram 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 safety requirements must my drilling unit meet?

Your drilling unit must meet all of the safety requirements in this section.

Required safety measure	When required	Additional requirements
(a) Crown block safety device	For each drilling unit	(1) The device must prevent the traveling block from striking the crown block. (2) You must check the device for proper operation once a week and after each drill-line slipping operation. (3) You must record the results of this operational check in the driller's report.
(b) Diesel engine air intake shut-down device.	For each diesel engine[1].	(1) For a diesel engine that is not continuously manned, you must install an automatic shutdown device.[1] (2) For a diesel engine that is continuously manned, you may install either a manual or automatic air intake shutdown device.
(c) Shut in all producible wells located in the affected wellbay.	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.
(d) Emergency shutdown station installed near the driller's console.	When you conduct drilling operations on a platform that has producing wells or other hydrocarbon flow.	

[1] You do not need to install an air-intake shutdown device on a diesel engine that starts a larger engine or that powers any of the following: (1) Firewater pumps; (2) Emergency generators; (3) BOP accumulator systems; (4) Air supply to divers or confined entry personnel; (5) Temporary equipment on nonproducing platforms; or (6) Portable single cylinder rig washers.

§ 250.404 What mobile drilling unit movements must I report?

You must report the movement of a mobile drilling unit on and off a drilling location to the District Supervisor. You must inform the District Supervisor 24 hours before the arrival of the rig on location and 24 hours before the rig departs from the location.

Applying for a Permit to Drill

§ 250.410 How can I apply for a permit to drill a well?

(a) You must obtain written or oral approval from the District Supervisor before you begin drilling any well. To obtain approval, you must :

(1) Submit the forms required by paragraph (b) of this section;

(2) Submit the information required by § 250.411;

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

(4) Meet the oil spill financial responsibility requirements for offshore facilities as required by 30 CFR part 253.

(b) You must submit the following forms to the District Supervisor:

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

(2) A separate public information copy of form MMS–123 that meets the requirements of § 250.127; and

(3) Form MMS–123S, APD Information Sheet.

§ 250.411 What material 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 a mobile drilling unit	250.417
(g) Additional requirements	250.418

§ 250.412 What requirements must my plat meet?

(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 items must my description of well drilling design criteria 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; and

(i) Permafrost zones, if applicable.

§ 250.414 What items must my drilling prognosis include?

(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 faults; and

(g) Estimated depths of permafrost, if applicable.

§ 250.415 What items must my casing and cementing programs include?

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

(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 information must be included 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 preventer 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; and

(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.

§ 250.417 What information must I provide if I intend to use a mobile drilling unit to drill a proposed well?

(a) *Fitness requirements.* You must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling operation. 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, the District Supervisor may require you to collect and report this information.

(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.

(c) *Third-party review.* If the design of the drilling unit 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.

(d) *Frontier areas.* 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).

(e) *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.

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

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

(h) Once the District Supervisor has approved a mobile drilling unit for use, you do not need to re-submit the information required by this section unless changes in equipment affect its rated capacity to operate in the District.

§ 250.418 What additional requirements must I meet?

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) 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) Proposed directional plot if the well is to be directionally drilled;

(d) Hydrogen Sulfide Contingency Plan (refer to § 250.470) if applicable and not previously submitted;

(e) Welding and Burning Plan (refer to § 250.106) if applicable and not submitted previously;

(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 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 departure; 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) *What casing and cementing programs must do.* 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.

§ 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.
(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.

Casing type	Casing requirements	Cementing requirements
(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 in the well. As a minimum, you must cement the annular space 500 feet above the casing shoe and 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 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 or production casing, 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 not resume drilling until the cement has been held under pressure for 12 hours. For conductor casing, you may not resume drilling until the cement has been held under pressure for 8 hours. Methods of holding cement under pressure include using 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, in advance, when it will be safe to conduct this activity. Your determination must consider cement composition, well conditions, and the effects of nippling down the equipment.

§ 250.423 How must I remedy cementing and casing problems and situations?

The table in this section describes remedies to problems and situations that lessees encounter on a regular basis during casing and cementing activities.

If you have the following problem or situation:	Then you must . . .
(a) Encounter unexpected formation pressures or conditions that warrant revising your casing design.	Submit a revised casing program to the District Supervisor for approval.
(b) Change casing setting depths more than 100 feet from the approved APD.	Submit those changes to the District Supervisor for approval.
(c) 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 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) Plan to produce a well	Have at least two cemented casing strings (does not include liners) in the well.
(g) Plan to wash out or displace some cement to facilitate casing removal upon well abandonment.	Obtain approval from the District Supervisor.
(h) Plan 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.
(i) Plan to use less than required cement for the surface casing during floating drilling operations.	Submit information to the District Supervisor that demonstrates the use of less cement is necessary to provide protection from burst and collapse pressures.
(j) Plan to cement across a permafrost zone	Use cement that sets before it freezes and has a low heat of hydration.
(k) Plan to 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 corrosion.
(l) If your problem or situation is not described in this table.	Contact the District Supervisor.

§ 250.424 What are the requirements for pressure testing casing?

(a) You must pressure test each string of casing to 70 percent of its minimum internal yield. 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.

(b) 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.

§ 250.425 What special pressure tests must I perform on casings for prolonged drilling operations?

(a) If wellbore operations continue for more than 30 days within a casing string run to the surface, you must stop drilling operations as soon as practicable thereafter 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.

§ 250.426 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.

§ 250.427 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. In addition, you must record each test on a pressure chart and have your onsite representative certify (sign and date) the test as correct.

§ 250.428 What are the requirements for pressure integrity tests?

You must conduct a pressure integrity test below the surface casing/liner and intermediate casing(s)/liner(s). 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 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.

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. 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. The diverter system consists of a diverter sealing element, diverter lines, and control systems.

§ 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 an internal 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 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 damage by thrown or falling objects.

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

The table below describes possible departures to the diverter requirements and the conditions required for each departure. To obtain one of these departures, you must have discussed or noted the departure in your APD.

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.
(e) If the departure you need is not described in this table	Contact the District Supervisor.

§ 250.433 How must I test the diverter system after installation?

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 of the previous test.

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system at least once every 7 days after the previous test.

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

§ 250.434 What are the recordkeeping requirements for diverter 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 certify (sign and date) the pressure test chart as correct;

(c) Identify the control station or pod 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;

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

(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.

Blowout Preventer (BOP) System Requirements

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

You must design, install, maintain, 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 have at least four remote-controlled, hydraulically operated BOPs, consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(b) One year after the effective date of this final rule, the surface BOP stack must have at least four remote-controlled, hydraulically operated BOPs consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind-shear rams.

(c) In addition to the stack, 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)(1) 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.

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

(3) In addition to the subsea stack, you must install the associated BOP systems and equipment required by the paragraphs below and the regulations in this subpart.

(b) You must install a subsea accumulator closing unit 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 alternate method.

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

(d) 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 BOP systems and related equipment must my BOP system include?

(a) 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.

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

(c) 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.

(d) 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.

(e) A choke and a kill line on the BOP stack. You must equip each line with two full-opening valves with at least one remote-controlled valve on each line. 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, you may install a check valve on the kill line instead of the remote-controlled valve. To use this check valve, both manual valves must be readily accessible, and you must install the check valve between the manual valves and the pump.

(f) A fill-up line above the uppermost preventer.

(g) Locking devices installed on the ram-type preventers.

(h) A wellhead assembly with a rated working pressure that exceeds the 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) Manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your 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 cocks, inside BOPs, and drill-string safety valves?

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

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

(b) A kelly cock installed at the bottom of the kelly (lower kelly cock). You must be able to strip the lower kelly cock 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 cock above, and one strippable kelly cock 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-cock-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-cock valves, drill-string safety valves, and comparable-type valves 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 must I do to maintain and inspect my BOP?

(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 Practice for Blowout Prevention Equipment Systems for Drilling Wells.

(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 conduct BOP system pressure tests?

You must pressure test your BOP system (this includes the choke manifold, kelly cocks, 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.

(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 comply with?

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

(b) Stump test a subsurface 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 during stump tests and at all casing points;

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

(f) Pressure test variable bore-pipe rams against all 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 annulars and rams 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 certify (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 preventers. You may reference a BOP test plan if it is available at the facility;

(d) Identify the control station or 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;

(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; and

(g) After drilling is completed, you must retain all the records listed in this section for a period of 2 years at the facility, at the lessee's field office nearest the facility, or at another location conveniently available to the District Supervisor.

§ 250.451 How do I remedy BOP problems and situations?

The table in this section describes remedies to problems and situations that lessees encounter with BOP systems on a regular basis during drilling activities.

If you have the following situation or problem:	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 preventer 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.
(i) If your problem or situation is not described in this table	Contact the District Supervisor.

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 are the required safe drilling fluid program practices?

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 fluids 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; and

(i) 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 must I have to test and monitor drilling fluids?

(a) You must have and maintain drilling fluid-testing equipment on the drilling rig at all times. You must test the drilling fluid 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. You must record the results of these tests in the drilling fluid report.

(b) 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:

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

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

(3) 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

(4) 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. 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 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 well testing?

(a) 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.

(b) If you intend to conduct a well test, you must include your projected plans for well testing with your APD (form MMS–123) or as a Sundry Notice and Reports on Wells (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.

(c) 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 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:

(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.

§ 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 that is applicable for the 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 you 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.

Sundry Notices and Well Records

§ 250.465 When must I submit sundry notices to MMS?

(a) You must submit sundry notices (form MMS–124) and other materials to the Regional Supervisor as shown in the following table. You must also submit a public information copy of each form.

If you . . .	then you must . . .	and . . .
(1) Intend to revise plans, change major drilling equipment, deepen, plug-back, or sidetrack a well.	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 oral approval, you must submit form MMS–124 within 72 hours. In all cases, you must meet the additional requirements in paragraph (b) of this section.
(2) Sidetrack	submit a form MMS–124	include the reason for the sidetrack, kickoff point, and applicable information as required for an APD (§§ 250.411 through 250.418)
(3) Determine that a well's final surface location, water depth, or the rotary kelly bushing elevation is different than permitted.	immediately submit a form MMS–124.	submit a plat that meets the requirements of § 250.412
(4) Move a drilling unit from a wellbore before completing a well.	submit forms MMS–124 and MMS–125 (Well Summary Report) within 30 days after the suspension of wellbore operations.	submit appropriate copies of the well records.

(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 weekly Activity Report, form MMS–133 (§ 250.467(c)).

§ 250.466 What well records must I keep?

You must keep complete, legible, and accurate records for each well. You must keep these records at your field office nearest the OCS facility or at another location conveniently available to the District Supervisor. 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.

§ 250.467 What well records may I be required to submit?

The Regional or District Supervisor may require you to submit copies of all the well records listed in this section.

(a) Well operations 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 and format for this information.

(c) Daily drilling reports. For drilling operations in the GOMR, you must provide this information on a weekly basis using form MMS–133, weekly Activity Report.

(d) Service company reports on cementing, perforating, acidizing, testing, or other similar services.

(e) Other reports and records of operations.

§ 250.468 How long must I keep drilling-related records?

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

You must keep records relating to . . .	until . . .
(a) Drilling	90 days after you complete drilling operations
(b) Casing and liner pressure tests, diverter tests, and BOP tests	2 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.

§ 250.469 Must I submit copies of well logs?

You must submit copies (field or final prints of individual runs) 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.

* * * * *

4. 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 preventers 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 preventers 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 preventers 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 one year from the final rule effective date	at least one set of blind-shear rams.

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5. 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 preventers 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 preventers 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 preventers 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 one year from the final rule effective date	at least one set of blind-shear rams.

Hydrogen Sulfide

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[FR Doc. 00–15546 Filed 6–20–00; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 166

[CGD08–00–012]

RIN 2115–AA98

Anchorage Regulation; Sabine Pass, TX, Gulf of Mexico

AGENCY: Coast Guard, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to create a new anchorage area on the eastern side of the Sabine Pass Safety Fairway, opposite the Sabine Bank Offshore (North) Anchorage area in the Gulf of Mexico south of Sabine Pass. This will help alleviate the need for in-bound deep draft vessels to cross the Sabine Pass Safety Fairway and navigate around a charted shallow area just to the southeast of the North anchorage. This proposal will allow deep draft vessels to enter and depart Sabine Bank anchorages on a safer, lower risk course.

DATES: Comments and related material must reach the Coast Guard on or before August 21, 2000.

ADDRESSES: You may mail comments and related material to Commanding Officer, U.S. Coast Guard Marine Safety