empty bogies. The coupler height of 27 inches is proposed to guard against the bogies becoming separated from the bogie consist of like equipment. All couplers would be equipped with uncoupling levers of approved type. The ICI trains would be powered by conventional locomotives.

The proposed test program using ICI equipment would involve operations from Greenville, New Jersey, through Brooklyn, New York, to Farmingdale, Long Island, New York. Containers on chassis would be loaded at the Greenville, New Jersey, yard on the CH. These bogies would be switched some 200–300 yards onto car floats and floated to the CH Yard at Brooklyn, New York, where they would be switched off the car floats and placed for interchange to the LI some quarter to a third of a mile away. LI would move the ICI train to Farmingdale, Long Island. The rail distance form Brooklyn to Farmingdale is about 35 miles. The speed of the operation would be 30 mph. The petitioners do not plan to ship hazardous materials at this time. Containers would move general merchandise. The project would be managed by the Freight Department of the LI in conjunction with the CH, with the LI in overall control.

FRA is considering the possibility of granting this waiver request subject to the following conditions and/or requirements:

1. During the initial test operations, CH and LI are limited to operating trains composed of no more than 15 bogies. After sufficient operational experience has been obtained, depending on test results, the use of additional units will be considered.

2. The test period must not exceed one year from the date of FRA's approval letter.

3. ICI units may not be commingled with conventional railroad rolling equipment. (Note: For the purpose of this waiver, "commingled" means that ICI bogies may only be operated in trains consisting exclusively of locomotive(s) and ICI bogies.)

4. The petitioners must determine effectiveness of train handling and vehicle tracking ability at various speeds over various track conditions (such as horizontal and vertical curves and low joints) and ability to traverse spring frogs, spring switches, self-guarded frogs, etc.

5. The petitioners must determine the degree of shunting effectiveness in block signal systems and at road crossing protection and advise FRA of its findings.

6. The petitioners must report immediately to FRA in detail any problems encountered during testing. They must provide written monthly reports relative to information compiled from operational testing and make the engineer's locomotive trip inspection reports available to FRA representatives.

7. FRA will permit the hauling of hazardous materials in ICI vehicles provided: (1) That the particular commodities are limited to those listed in table 2 of 49 CFR 172.504; and (2) that the shipment of such hazardous materials complies with other relevant provisions of the hazardous materials regulations. Additionally, FRA will permit the operation of the ICI vehicles under the placarding provisions of 49 CFR Part 172 Subpart F during rail movement of these vehicles; however, it should be understood that cargo tanks, multi-unit tank car tanks, portable tanks and intermodal (IM) portable tanks handling hazardous materials are not permitted in this service.

8. Each ICI bogie unit that has two couplers of non-standard height must be stenciled toward the ends of each side, in clearly legible letters not less than 3 inches high, "NON-STANDARD COUPLER HEIGHT" in any location that is visible to a person walking at track level beside the unit. Each ICI bogie unit that has only one coupler of non-standard height must be stenciled at a location on each side toward the end of the side near the coupler of non-standard height, in clearly legible letters not less than 3 inches high, "NON-STANDARD COUPLER HEIGHT" in any location that is visible to a person walking at track level beside the unit.

Issued in Washington, DC, on March 25, 1988.

J.W. Walsh,

Associate Administrator for Safety.

[FR Doc. 88–7117 Filed 3–31–88; 8:45 am]

BILLING CODE 4910–06–M

DEPARTMENT OF THE TREASURY

Office of the Secretary

[Supplement to Department Circular; Public Debt Series No. 7–88]

Treasury Notes, Series Y–1990

Washington, March 24, 1988.

The Secretary announced on March 23, 1988, that the interest rate on the notes designated Series Y–1990, described in Department Circular—Public Debt Series—No. 7–88 dated March 17, 1988, will be 7⅜ percent. Interest on the notes will be payable at the rate of 7⅜ percent per annum.

Gerald Murphy,

Fiscal Assistant Secretary.

[FR Doc. 88–7115 Filed 3–31–88; 8:45 am]

BILLING CODE 4810–40–M

[Supplement to Department Circular; Public Debt Series No. 8–88]

Treasury Notes, Series M–1992

Washington, March 25, 1988.

The Secretary announced on March 24, 1988, that the interest rate on the notes designated Series M–1992, described in Department Circular—Public Debt Series—No. 8–88 dated March 17, 1988, will be 7⅞ percent. Interest on the notes will be payable at the rate of 7⅞ percent per annum.

Gerald Murphy,

Fiscal Assistant Secretary.

[FR Doc. 88–7116 Filed 3–31–88; 8:45 am]

BILLING CODE 4810–40–M

Sunshine Act Meetings

Federal Register
Vol. 53, No. 63
Friday, April 1, 1988

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

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TIME AND DATE: Friday, April 8, 1988.

PLACE: 1111 20th Street, NW. Suite 450, Washington, DC 20036.

STATUS: Closed pursuant to a vote taken March 14, 1988.

MATTERS TO BE CONSIDERED:
Adjudication of the 1986 jukebox distribution proceeding.

CONTACT PERSON FOR MORE INFORMATION: Robert Cassler, General Counsel, Copyright Royalty Tribunal, 1111 20th Street, NW. Suite 450, Washington, DC 20036, 202–653–5175.

Dated: March 30, 1988.
Edward W. Ray,
Acting Chairman.
[FR Doc. 88–7273 Filed 3–30–88; 12:14 pm]
BILLING CODE 1410-09-M

NUCLEAR REGULATORY COMMISSION

DATE: Week April 4, 1988.

PLACE: Commissioners' Conference Room, 1717 H Street, NW., Washington, DC.

STATUS: Open and Closed.

MATTERS TO BE CONSIDERED:

Week of April 4

Wednesday, April 6

2:00 p.m.
Briefing on Basic Safety Principles for Nuclear Power Plants (Public Meeting)

Thursday, April 7

2:00 p.m.
Briefing on Proposed Basic QA Rule with Representatives of NRC Advisory Committee on the Medical Uses of Isotopes and Industry Scientific Committees (Public Meeting)

3:30 p.m.
Affirmation/Discussion and Vote (Public Meeting) (if needed)

Note:—Affirmation sessions are initially scheduled and announced to the public on a time-reserved basis. Supplementary notice is provided in accordance with the Sunshine Act as specific items are identified and added to the meeting agenda. If there is no specific subject listed for affirmation, this means that no item has as yet been identified as requiring any Commission vote on this date.

TO VERIFY THE STATUS OF MEETINGS CALL (RECORDING): (202) 634–1498.

CONTACT PERSON FOR MORE INFORMATION: William Hill (202) 634–1410.

William M. Hill, Jr.,
Office of the Secretary.
March 29, 1988.

[FR Doc. 88–7306 Filed 3–30–88; 3:36 pm]
BILLING CODE 7590-01-M

federal register

Friday
April 1, 1988

Part II

Department of the Interior

Minerals Management Service

30 CFR Parts 250 and 256

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

DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Parts 250 and 256

Oil and Gas and Sulphur Operations in the Outer Continental Shelf; Outer Continental Shelf Minerals and Rights-of-Way Management, General; and Outer Continental Shelf Orders for All Regions of the Outer Continental Shelf

AGENCY: Minerals Management Service, Interior.

ACTION: Final rule.

SUMMARY: This rule restructures and consolidates into one document the existing multitier rules of the Offshore program of the Minerals Management Service (MMS) that govern oil, gas, and sulphur exploration, development, and production operations in the Outer Continental Shelf (OCS). The new rule is intended to eliminate redundant, burdensome, unnecessary, and counterproductive requirements imposed by the existing rules; introduce more performance standards; introduce new and updated requirements; and simplify the language of the rules.

EFFECTIVE DATE: May 31, 1988. (The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of May 31, 1988.)

FOR FURTHER INFORMATION CONTACT: Gerald D. Rhodes, Chief, Branch of Rules, Orders, and Standards; telephone (703) 648-7816, (FTS) 959-7816.

SUPPLEMENTARY INFORMATION:

Synopsis

The MMS is restructuring and consolidating the rules governing oil, gas, and sulphur exploration, development, and production operations in the OCS. This effort is directed towards minimizing the recordkeeping and reporting burden on industry while maintaining or increasing the existing levels of safety and protection provided for the environment. This was accomplished by addressing issues identified by MMS as well as issues raised by industry in response to a request from the Secretary of the Interior (Secretary) for the identification of regulations in need of change.

The MMS established the goal of minimizing the recordkeeping and reporting burden on industry while maintaining the levels of safety and environmental protection mandated by statute through the following specific objectives:

(1) To restructure and consolidate past lease operating requirements placed upon OCS oil, gas, and sulphur lessees into a single document (i.e., eliminating the multitier structure of existing rules);

(2) To establish performance standards in preference to detailed technical standards to the extent that protection of the environment and safety of operations permit;

(3) To update safety and environmental requirements, recognize needs identified by technological advances, improve operating practices and experience;

(4) To eliminate unnecessary reporting and recordkeeping requirements; and

(5) To clarify and simplify the language of the rule and eliminate redundant and inappropriate provisions.

Current regulations at 30 CFR Part 250, Oil and Gas and Sulphur Operations in the Outer Continental Shelf; OCS Orders developed to govern operations conducted in each of MMS's four OCS Regions; and portions of selected Notices to Lessees and Operators (NTL) issued by MMS's regional offices were combined into a restructured and expanded Part 250 of Title 30 of the Code of Federal Regulations. This rule is organized into 16 subparts reflecting specific subject matter; e.g., Drilling Operations and Remedies and Penalties. Fourteen of these subparts (A through N) are being promulgated by this action while two subparts (O and P) are still under development.

The following summarizes the major changes from current rules:

(1) *Performance Standards.* Performance standards were added which describe the safety, environmental, property, and resource protection goals intended to be achieved by specified design and engineering requirements. These additions are intended to identify the purpose of the detailed requirements and thus provide a basis for approving an alternative method for achievement of the stated purpose. New, different, better, and more efficient techniques and practices are intended to be available to lessees on the basis of these performance standards.

(a) *Performance Requirements.* A "Performance requirements" section was added. This section clarifies that the specific detailed requirements of the rule do not preclude the approval for use of alternate or new techniques, procedures, equipment, or activities when the lessee satisfies MMS that the proposed alternate approach provides equal or greater protection than that provided by the requirements specified in the rule. The establishment of performance standards in addition to specific detailed requirements is intended to remove obstacles to innovation and ensure that MMS's regulations are not unnecessarily prescriptive.

(b) *Well Casing Performance Characteristics.* A performance standard has been substituted for the reference in existing regulations which incorporates the requirements contained in eight American Petroleum Institute (API) documents. The MMS's review and approval/disapproval of lessee's Applications for Permit to Drill (APD) and subsequent MMS compliance inspections will provide for review and control over the quality of casing being used.

(c) *Well Casing Setting Depths.* Specified depths for setting the conductor and surface casing in a well have been deleted. A lessee's proposed casing programs, including the proposed setting depths for conductor and surface casing, will be carefully reviewed by MMS technical personnel before the lessee's APD is approved.

(d) *Well Completions and Well Workovers.* New and updated requirements have been added to this portion of the regulations (Subparts E and F), together with new performance standards for well-control fluids, blowout-prevention equipment, tubing, and wellhead equipment. This approach was considered more appropriate than the detailed prescriptive requirements proposed by MMS in May 1983.

(e) *Blowout-Prevention Systems.* Performance standards replace the requirement practices found in API recommended documents for blowout-prevention systems previously incorporated by reference.

(2) *New Requirements.* New or updated requirements have been adopted on the basis of operating experiences and recommendations made by MMS and U.S. Coast Guard (USCG) accident investigation panels. Whenever possible, these new requirements have been described in terms of minimum acceptable performance standards rather than prescribed design details.

(a) *Periodic Inspections and Maintenance.* Existing MMS regulations and rules contain no specific provisions spelling out the lessee's obligation to periodically inspect and maintain offshore platforms. The new rule anticipates problems that may develop as platforms become older and are built in deeper waters and more hazardous areas by inclusion of a minimal regulatory approach with simple reporting to MMS.

(b) *Well-Completion and Well-Workover Operations.* More accidents occur in association with well-completion and wellworkover operations than with drilling operations. In May 1983, MMS proposed a comprehensive set of rules for these activities. This rule establishes performance standards together with other new requirements which represent widespread accepted practices. During well-completion and well-workover operations, new requirements are applicable with respect to equipment movement, emergency shutdown systems, hydrogen sulfide protection, subsea completions, crew instructions, welding and burning, electrical requirements, structures on fixed platforms, prevention of diesel engine "runaway," simultaneous operations, field rules, well control, blowout prevention, and tubing and wellhead equipment. The rule also includes requirements which must be observed during well-workover wireline operations. Many of the requirements prescribed for well-completion and well-workover operations are patterned after similar requirements which are applicable to drilling operations.

(c) *Hydrogen Sulfide (H_2S).* The H_2S protection requirements and procedures have been expanded to include production, well-completion, and well-workover operations as well as drilling operations. Hydrogen sulfide represents a threat to human life and safety and to the survival of equipment. The final rule concerning H_2S protection was tailored to be applicable to operations being conducted in an area known to contain H_2S, an area where the presence (absence) of H_2S is unknown, or an area where H_2S is known not to be present.

(d) *Diverter Equipment.* This equipment maintains a degree of control by diverting the gas flow to the side and away from the rig and personnel to provide for safe evacuation of the crew and to avoid hydrocarbon flow at the rig floor while steps may be taken to regain well control. This action is designed to prevent the destruction of the facility, loss of life or injury, and loss of resources which could result from an uncontrolled blowout. The new rule requires the use of diverters of a specific minimum size configuration (large diameter pipe and minimum turns).

(e) *Extension of Lease Terms.* Under the revised rule, the MMS Director is authorized to grant a request allowing more than 90 days between drilling or well-reworking operations which serves to continue a lease beyond its fixed term. In the absence of such an approval, the time allowed between drilling or well-reworking operations that earn lease continuance remains 90 days.

(f) *Additions to Development and Production Plans.* Development and Production Plans (DPP) are now required to include narrative descriptions of any new or unusual technology which the lessee proposes to employ and technology and practices considered by the lessee as a means intended to increase the ultimate recovery of oil and gas.

(g) *Pollution Prevention and Control.* New provisions include restrictions on the rate of discharge for drilling fluid, requirements for berms on artificial islands, and additional information requirements for oil spill contingency plans.

(h) *Additional Safety Devices.* Requirements have been added for crown block safety devices and for devices to mitigate hazards due to diesel engine "runaway" (i.e., stop a runaway diesel engine).

(i) *Pipelines.* Provisions governing offshore pipelines include expanded requirements governing design, installation, testing, safety equipment, abandonment, and reporting.

(j) *Flaring and Venting.* Provisions relating to the flaring and venting of gas were revised to clarify the intent of requirements in OCS Order No. 11.

(k) *Enhanced Recovery of Oil and Gas.* Clarifying details were added to provisions concerning enhanced recovery previously contained in OCS Order No. 11.

(l) *Site Security.* Provisions are designed to ensure against the loss or theft of produced minerals. Provisions to assure accurate measurement of mineral products for royalty purposes have been included in the final rule.

(m) *Enclosed Mud Rooms.* Requirements for gas detection systems in enclosed mud-handling rooms are included in the final rule.

(3) *Reduced or Eliminated Requirements.* Operating requirements contained in the previous rules have been reduced or eliminated where there would be no adverse impact on the safety of operations or protection of the environment. Operating requirements are eliminated only when the requirements are no longer needed or where the objectives of a detailed prescriptive requirement are better accomplished by the substitution of a performance standard.

(a) *Determination of Producibility.* Lessees are no longer required to request a determination of producibility for each well drilled on an OCS oil and gas lease. A determination of producibility will continue to be needed before a suspension of production will be granted. Elimination of the requirement for producibility determination for every well completed in the OCS will save lessees and MMS considerable time and money.

(b) *Maximum Efficient Rate (MER) on Nonsensitive Reservoirs.* Provision is made for reservoirs to be classified as sensitive or nonsensitive. A MER will be established only for the reservoirs which are classified as sensitive.

(c) *Orientation and Motivational Training.* The orientation and motivational training requirements previously contained in OCS Order No. 7 have been deleted. This eliminates the requirement found in API's Recommended Practice, Orientation Program for Personnel Going Offshore for the First Time (API RP T-1) and API Bulletin, Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations (API Bull. T-5), that were incorporated by reference under the previous rules. The training requirements for oil spill response teams contained in OCS Order No. 7 continue to apply. They are contained in Subpart C, Pollution Prevention and Control. Training requirements for lessee's drilling and production personnel are contained in Subparts D, H, and O.

(4) *Reduced Recordkeeping and/or Reporting.* Recordkeeping and reporting requirements have been reduced or eliminated when that action would not adversely impact MMS's ability to obtain required information or reduce the level of safety or environmental protection.

(a) *Critical Operation and Curtailment Plan.* The requirement for the submission of a Critical Operation and Curtailment Plan has been eliminated. The information contained in that plan is properly part of the lessee's proposed Exploration Plans (EP), Development and Production Plans (DPP), and APD's.

(b) *Exploration Plan and Development and Production Plan.* The rule permits the MMS Director, after consultation with the affected States, to reduce the amount of information a lessee must submit in support of its EP or DPP (Development Operations Coordination Document (DOCD) in the western Gulf of Mexico).

(c) *Changes to Plans.* The rule permits a lessee to submit only the portions of approved EP's or DPP's which are actually proposed for change. In the past, some lessees have felt obliged to resubmit a complete new plan when a change from approved operations was proposed.

(d) *Erosion-Control Program Report.* An annual report by the lessee on its erosion-control programs is no longer required. Lessees are still required to have erosion-control programs, to maintain records of the results obtained, and to make the records available for examination by MMS personnel.

(e) *Pipeline-Safety Reports.* The new rule does not require the submission of semiannual reports on pipeline-safety devices and annual reports of monthly pipeline inspections. The information on pipeline installation, maintenance, operation of safety devices, and conduct of the monthly inspections would continue to be required to be available for examination by MMS personnel.

(5) *References to Technical Documents.* The rule incorporates technical documents by specific reference to the relevant portions of the document.

(a) *Well-Casing Requirements.* The new rule uses a performance standard in lieu of the eight API documents concerning well casing. The API documents do not provide sufficient flexibility to allow a lessee to meet the desired standard of performance in the most effective manner.

(b) *Electrical Systems.* The rule incorporates essential requirements for electrical systems by reference in API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms, and API RP 500B, Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms.

(c) The proposed rule published in the **Federal Register** on March 18, 1986 (51 FR 9316), identified numerous documents developed by various standard writing groups which were incorporated by reference. These documents are listed in Subpart A of the final rule at § 250.1, Documents incorporated by reference. A supplemental notice of proposed rulemaking was published in the **Federal Register** on September 22, 1987 (52 FR 35559), to update the identification of specific editions of incorporated documents. Comments received in response to the supplemental notice of proposed rulemaking are included in the discussion of comments received regarding Subpart D. References to API Spec 14A, Specification for Subsurface Safety Valve Equipment, and API Spec 14D, Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, have been deleted since they are not referred to in the final rule.

(6) *Simplified Format and Wording.* Restructuring and consolidation of MMS's multitier system of rules into a single comprehensive system of rules greatly simplifies the format of the new rule. Portions of the previous rules have been restructured and reworded for increased clarity. For example, in Subpart N, Remedies and Penalties, the language has been streamlined and simplified. Portions of the previous rules which constituted instructions to MMS personnel were removed.

(7) *Other Changes.* A number of other changes were made in the new rule in an attempt to meet established objectives.

(a) *Preliminary Activities.* The new rule defines preliminary activities—those activities which occur prior to the activities described in an EP or a DPP—to permit seabed penetrations of up to 500 feet. Preliminary activities do not require prior notification to MMS or prior MMS approval except as may be required by the Regional Supervisor. In areas where shallow gas or other hazards might be present, the District Supervisor may specify appropriate notification and approval procedures.

(b) *Environmental Reports.* Under the new rule, an EP or DPP may be combined with the supporting Environmental Report as a single document. The combined document must contain the information required when the Environmental Report and corresponding EP or DPP are submitted as separate documents.

(c) *Changes in Approved Plans.* The new rule recognizes the possible significance of proposed modifications to approved EP's or DPP's and provides for Coastal Zone Management agency review of proposed modifications.

(d) *Model Unit Agreements (MUA).* Two MUA's are included in the final rule. The previously approved MUA was updated and adopted to two basic situations, one for the unitization of operations for exploration, development, and production and one for the unitization of operations after discovery and delineation of a reservoir(s).

(e) *Extension of Lease Term by Production, Drilling, or Well Reworking.* Current rules provide that continuous production, drilling, or well reworking with no time lapse greater than 90 days will serve to continue a lease in effect beyond the term specified in the lease. The new rules permit the MMS Director to allow a time lapse of up to 180 days between continuous drilling or well reworking operation when circumstances warrant.

(f) *Criteria for Determinations.* The rule spells out the criteria to be considered by the District or Regional Supervisor when making certain determinations.

(g) *Identification of Specific Authorities and Responsibilities.* The regulations identify MMS's officials delegated specific authorities and responsibilities. Where an authority has been delegated to a specific MMS official, that authority may be exercised by any MMS or Department of the Interior (DOI) officer in the line of authority above the officer identified in the regulations. Delegations of authority in DOI are effected through DOI manual publications. The new rule simply identifies the responsible official named in DOI manual chapters on delegated authority.

(h) *Timing of the Exploration Plan.* The requirement that an EP be submitted by the fourth year of a lease term has been deleted. Lessees are fully aware that the failure to explore, discover, develop, and produce by the end of the primary term will result in the expiration of the lease.

(i) *Pipelines and Pipeline Rights-of-Way.* The rule applies to the permitting of pipelines on a lease as well as the granting of pipeline rights-of-way off the lease. The granting of pipeline rights-of-way were previously covered in 30 CFR Part 256, Outer Continental Shelf Minerals and Rights-of-Way Management, General.

Background

Executive Order (E.O.) 12291, February 17, 1981, requires Agencies to "initiate reviews of currently effective rules in accordance with the purposes of the Order." One of the stated purposes of the Order is to reduce the burdens of existing regulations. Since the issuance of E.O. 12291, MMS has been reviewing and revising its rules governing operations in the OCS on an individual subject matter basis. The changes made prior to March 18, 1986, were itemized in the preamble of the notice of proposed rulemaking.

On February 22, 1983, the Secretary asked the public for suggestions and recommendations for reform of DOI's rules, including MMS's rules governing oil, gas, and sulphur operations in the OCS found in 30 CFR Part 250. Numerous comments, recommendations, and suggestions were submitted in response to the Secretary's request.

During the summer of 1983, the MMS Director appointed a Regulatory Reform Task Force of senior MMS personnel from headquarters, regional, and district offices to examine those recommendations and to look at the system of rules governing offshore postlease mineral operations, particularly those found in 30 CFR Part 250, Oil and Gas and Sulphur

Operations in the Outer Continental Shelf, the Regional OCS Orders (including standards and other reference documents), and appropriate NTL's. The Task Force reviewed the various rules and related documents with the view toward restructuring and consolidating the multitiered system of rules into a single set of rules.

Current Rules

Offshore operating rules developed since 1954 took the form of regulations, OCS Orders, Standards, NTL's, conditions of approval, and related documents. The rule codified in Title 30 Part 250 of the Code of Federal Regulations underwent major revisions following the enactment of amendments to the OCS Lands Act (Act) in 1978. They are rules of general applicability often stated in general policy terms. The OCS Orders are rules of general applicability adopted in compliance with rulemaking requirements, published in the **Federal Register**, but not codified in the Code of Federal Regulations. The OCS Orders were adopted on a Region-specific basis with separate sets of OCS Orders for the Alaska, Atlantic, Gulf of Mexico (GOM), and Pacific OCS Regions. The OCS Orders implemented provisions of the regulations in 30 CFR Part 250 in more specific detail—often in terms of particular technical requirements. The requirements were essentially consistent from Region to Region; however, there were variations to accommodate local environmental conditions, e.g., severe arctic weather in portions of the Alaska OCS Region. Standards are documents developed by MMS and referenced in the OCS Orders, thereby becoming requirements. Standards included statements of recommended practices adopted by the offshore industry and trade associations, such as API, or professional standards writing organizations, such as the American National Standards Institute (ANSI). Initially, NTL's were used to inform lessees of DOI's interpretations of its requirements. The NTL's were not intended to impose new requirements. However, NTL's and the conditions placed upon required approvals occasionally imposed new requirements. In this restructuring and consolidation of MMS's multitier system of rules into a new expanded 30 CFR Part 250, efforts were made to eliminate any inconsistency and redundancy in the current rules. References to incorporated material were eliminated or the materials referenced specifically identified as narrowly as possible.

It is recognized that implementation of the restructured offshore operating rules will necessitate increased effort on the part of OCS lessees and the Government. It is also expected that after some initial difficulty the long-term benefits from use of the consolidated and comprehensive presentation of those rules will far outweigh the initial inconveniences.

Proposed Changes to Rules

The MMS published a **Federal Register** Notice on March 18, 1986 (51 FR 9316), soliciting comments on the proposed rule. This notice provided for receipt of comments through June 16, 1986. At the request of several respondents, MMS published a **Federal Register** Notice on May 2, 1986, which extended the comment period through September 15, 1986.

Public meetings were held in Los Angeles, California, on August 5, 1986, and in New Orleans, Louisiana, on August 7, 1986. At each of the meetings, MMS summarized major points in the proposed rule and responded to the questions which had been received and additional questions from the attendees at the meetings.

The MMS received numerous comments from various interested parties. Based on the notices which had been published, MMS was precluded from considering a number of comments because they were received or postmarked after September 15, 1986. It was apparent that a great deal of thought had been expended in preparing those late comments, and MMS wanted to consider all significant comments. It was also recognized that other parties may have prepared significant comments and then chose not to submit their comments because they could not be delivered or postmarked by September 15, 1986. A **Federal Register** Notice on November 10, 1986 (51 FR 40819), reopened the comment period until November 25, 1986. This enabled MMS to consider all comments received while providing all parties with an equal opportunity to submit additional comments.

A total of 84 comments were received from various groups including the offshore petroleum industry, support contractors, training companies, State and local governments, Federal Agencies, environmental groups, and various other parties. The comments were considered by the Task Force which developed the proposed rule. The proposed rule was modified where warranted to adopt specific recommendations or to clarify specific provisions.

Discussion of General Comments

Comment—Many commenters agreed with the objectives of the proposed rulemaking—the restructuring and consolidation of existing rules into a single document, elimination of redundancy, reduction of paperwork, introduction of additional performance standards, and simplification of the rules—and commended MMS for its efforts toward those objectives. However, many of these same commenters felt that the proposed rules, in general, continued to be too detailed and prescriptive in nature. They provided numerous suggestions and recommendations for further changes to the proposed rules.

Response—The MMS is encouraged by the positive response to the proposed rule. The MMS appreciates the time, effort, skill, and cooperation of the commenters in reviewing the proposed rule and offering constructive suggestions for improvement. Where suggestions were adopted, they are reflected in the final rule. A constant guide for the task force was a balance of reducing the regulatory burden while maintaining or increasing the level of safety in operations and environmental protection.

Comment—One commenter observed that many of the proposed changes are in response to expressed concerns.

Response—The MMS has tried to be responsive to legitimate concerns when they can be accommodated without diminishment of the safety of operation or environmental and resource protection.

Comment—One commenter submitted extensive new suggestions for the regulation of sulphur exploration, development, and production activities.

Response—These comments have been considered during the development of revised and restructured rules to govern sulphur operations in the OCS. Since MMS intends to publish those proposed rules for comment, the provisions for OCS Order No. 10, Sulphur Drilling Procedures, are being incorporated into the proposed rule for sulphur operations. The GOM OCS Order No. 10 continues in force until a revised and restructured final rule is published to govern sulphur operations in the OCS.

Comment—One commenter objected to MMS's failure to make an Environmental Assessment (EA) available with the proposed rule. Also, the commenter inquired as to when the EA would be available and how copies could be obtained.

Response—An EA was in preparation at the time the proposed rule was prepared. An EA is being issued in connection with the final rule. The EA is available to the public for inspection at each MMS Regional Director's office and MMS headquarters office.

Comment—A number of commenters recommended that NTL's should be rescinded and a new set issued consistent with the new regulations. They also recommended that NTL's be limited to interpretations and administrative information.

Response—The MMS plans to review all NTL's in light of the new regulations. Those NTL's that are out of date will be rescinded and new NTL's will be issued as needed under the new rules.

Comment—One commenter expressed concern about MMS's relationship to the Environmental Protection Agency (EPA) and USCG. The commenter recommended that detailed Memoranda of Understanding (MOU) be developed with those Agencies.

Response—The MMS is aware of the continuing need to coordinate its efforts with those of EPA and USCG. To this end, MMS has developed MOU's with those Agencies and continues to work with those Agencies as much as possible.

Comment—A number of commenters responded to a question posed in the proposed rule as to whether it would be desirable to refer to equipment by a brand name, model number, or other standardized designation in the interest of reducing reporting and recordkeeping burdens. All commenters who responded to this question expressed a desire that the rules continue to use specifications and descriptions for equipment rather than brand names or model numbers. It was the commenters' view that more paperwork would be generated by the use of brand names or model numbers.

Response—The MMS will continue to use specifications and descriptions of equipment rather than brand names or model numbers.

Comment—In response to a question posed in the proposed rule as to whether MMS should retain its role as intermediary between lessees and States for reporting of information used by States in making determinations under the Coastal Zone Management Act (CZMA) and other purposes, one commenter recommended that lessees not be obliged to deal with multiple State information requirements.

Response—The MMS will continue to cooperate with OCS mineral lessees and States so that all entities with legitimate review responsibilities are provided the information required for their review. The MMS cannot relieve OCS lessees of their obligations to meet both Federal and State information requirements.

Discussion of Specific Comments

A discussion of the significant comments that were received on the proposed changes to the Consolidated Offshore Operating Rule published March 18, 1986 (51 FR 9316), follows: Comments and responses are grouped on the basis of subject matter, first by subpart for general comment and then by section when the comments relate to a specific section or paragraph.

Subpart A—General

This subpart sets out requirements that basically apply to all operations. The sections span from § 250.0, Authority for information collection, to § 250.24, Appeals, general.

Thirty-three comments responding to the Notice of March 18, 1986 (51 FR 9316), were received concerning Subpart A—26 from the oil and gas industry or related associations, 4 from States, 2 from Federal Agencies, and 1 from an environmental group. Generally, the comments were favorable; therefore, the majority of the subpart remains as proposed. The changes that were made are reflected in the final rule. Five comments were received in response to the supplemental notice of September 22, 1987 (52 FR 35559), from members of the oil and gas industry and related associations. A summary and analysis of the comments received follows.

Comment—Several comments were received concerning incorporations by reference in § 250.1. The practice of incorporating documents by reference was questioned on the basis that "many have never been subjected to public review and comment as required by [Administrative Procedure Act]," and a number of commenters recommended that MMS incorporate the "latest edition" of a document rather than a document of a specific date. It was claimed that this would relieve MMS and the regulated industry of a large administrative burden.

Response—Documents are incorporated by reference only through the rulemaking process. That action exposes them to public review and comment, in accordance with the legal requirements of the Administrative Procedure Act. Compliance with these requirements, precludes the incorporation of the "latest edition" of a document or standard. It should also be noted that the rules of the Federal Register governing incorporation by reference require that the Director of the Federal Register approve the documents and that copies of the documents be on file with the Federal Register.

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

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

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

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

Comment—A number of commenters recommended newer editions and/or supplements for cited documents, and recommended additional documents for incorporation by reference.

Response—Some of the documents suggested for incorporation by reference are not yet available for public review. Thus, it is premature to consider incorporation of those documents by reference. As new editions and supplements to existing documents and new documents are recommended for incorporation by reference, consideration will be given to the incorporation of those documents by reference.

Comment—It was recommended that any conflicts between the USCG and MMS, with respect to their respective regulations incorporating documents by reference, should be resolved before the final rule is published—especially as the rules relate to mobile offshore drilling units (MODU). There are instances where the USCG incorporates one part of a document, and MMS incorporates another part of the same document.

Response—The USCG and MMS regulations may correctly incorporate by reference different parts of the same document into their respective regulations based on different uses and purposes. However, an effort has been made and will continue to be made to

identify and eliminate any conflicts between USCG and MMS regulations.

Comment—A number of commenters recommended that all definitions be grouped in Subpart A rather than in each of the subparts.

Response—To better assist the users of these regulations, we have grouped the definitions in Subpart A. Specific definitions appropriate to each subpart will be repeated with that subpart.

Comment—Specific recommendations were made to add certain definitions.

Response—The definitions of "Competitive reservoir" and "Lessee" have been added to Subpart A.

Comment—Commenters suggested certain changes in proposed definitions.

Response—The suggestions to amend "Affected State" and "Development" and "Fair market value" were not adopted because these terms are defined in the Act. The definition of the term "Fair market value" has been deleted from the rule since it is not used in Part 250. In these cases, use of the definitions as they appear in the Act best meets the intent of the law.

Comment—It was suggested that we combine the definition of "Interpreted geological information" with "Interpreted geophysical information" and "Processed geological information" with "Processed geophysical information" to eliminate repetitive language.

Response—By combining the definitions (which are largely, but not entirely, redundant), ambiguity would result. Only parts of the definition would relate to a defined term while other parts would not. The basic function of the definition would be defeated. Therefore, the four definitions have been left separate.

Comment—Several commenters recommended that the definition of "Operator" be amended by adding the word "operating" to characterize "rights" under an "operating agreement." It was pointed out that not all interests or rights under an operating agreement are operating rights.

Response—The word "operating" has been inserted.

Comment—The view was expressed that the performance standards lack specificity and so do many of the requirements. Vague terms such as "sound conservation practice," "probably cause serious harm," "satisfactory," and "soon" should not be used. The commenter recommended use of terms such as "best available control technology" (BACT), "standard industry practice," "maximum extent feasible," and other widely accepted terms.

Response—Performance standards for most aspects of the Offshore Operating Program cannot be stated with numerical precision, as is available in the case of emissions limitations. For that reason, the performance standards supplement, but do not replace, appropriate prescriptive requirements. The recommended phrases such as "standard industry practice" provide no more specificity than phrases such as "sound conservation practice." Care must be taken in using phrases such as BACT which has legal significance in the context of the Clean Air Act and the Clean Water Act and is used in §§ 250.45 and 250.46 concerning air quality. It should not be confused with "Best available and safest technologies" (BAST) which is addressed in § 250.22.

Comment—The use of performance standards as a substitute for detailed requirements is objectionable because the proposed performance standards are "so general and vague."

Response—In almost all cases, the performance standards are not in substitution of, but in addition to, detailed requirements. We believe that inclusion of the performance standards helps to identify the underlying purpose of the specific requirements. Because the nature of the activities regulated are not readily amenable to performance standards, these standards are fairly general. They are descriptions of the safety, environmental, property, and resource protection goals intended to be achieved by the design and engineering requirements. They are intended to identify the purpose of the detailed requirements and provide a basis for alternative achievement of such purpose. New, different, better, and more efficient techniques and practices can be available to lessees on the basis of these performance standards.

Comment—A number of commenters agreed with the performance-standard approach whereby alternatives to prescribed requirements are available if shown by lessees to be equal or superior to those requirements, but it was suggested that a mechanism be provided whereby alternatives be demonstrated to produce equal or superior results.

Response—Demonstrations may be required by the Regional or District Supervisor as evidence necessary for obtaining approval for use of alternative equipment or techniques. However, we do not believe that demonstrations need be required in every case.

Comment—While supporting the general performance standards as providing "a desirable amount of flexibility," the suggestion was made that procedures should be spelled out and should include public review and comment and written findings.

Response—This comment was not adopted. In reviewing a request under the performance standard provision, the specific procedure to be followed by MMS will depend on the character and scope of the requested change. When changes impact on the plan of development and production, they will be discussed in the plan, and the public will have an opportunity to comment on the performance standard criteria when they comment on the plan. Comments received will be considered by MMS in evaluating the lessee's request. In most cases, approval under the performance standard provision will be needed by the lessee soon after the request is made, and public comment will not be practical. The MMS will evaluate the request based on available information and will approve the request only if MMS can determine that the requested action or equipment provides for equivalent or better levels of safety of operations and environmental protection than that which is provided for in the rules. Public comment will be requested if needed to make such a determination. When MMS believes that a particular request or series of requests warrants consideration as an amendment to the regulations, the change will be published as a proposed rule, and interested parties will have an opportunity to comment.

Comment—It was commented that authorizing performance standards "may lead to any and all alternative practices," and that the EPA or a State agency should review all alternatives to assure that environmental protection will not be diminished.

Response—This recommendation was not adopted. There is adequate provision for review of proposed alternatives by EPA, State agencies, or others. The responsibility for implementation of requirements under the Act, including environmental protection, is placed with the Secretary, who consults with other Federal and State agencies, as appropriate. For example, procedures for the evaluation of EP's and DPP's specifically provide for consultation and review by States and other Federal Agencies.

Comment—One commenter requested that a provision for oral approval with subsequent written confirmation be available for performance standard alternatives.

Response—Oral approvals are available in § 250.6 and could be used by Regional or District Supervisors for performance-standard approvals.

Comment—The criteria for granting departures were characterized as broad. Commenters also suggested that

departures should be limited to emergencies and should not be available to facilitate "the proper development of a lease." Commenters believed that such authority appeared to undercut the value of having a comprehensive set of operating regulations.

Response—The MMS recognizes that the "proper development of a lease" criterion is broad and provides considerable discretion to District and Regional Supervisors. However, this is not new authority, and there has been no history of abuse. On the contrary, it has provided the desired flexibility and has been used with restraint only when dictated by circumstances. Therefore, the section has not been changed.

Comment—Several commenters recommended that all information and data submitted in connection with departures should be protected as proprietary in accordance with § 250.18(a).

Response—Section 250.18(a) and any other provisions apply, as appropriate, by their own terms to § 250.3 and other provisions in this part. There is no need to repeat such provisions with respect to every section where they apply.

Comment—A number of commenters recommended that "Director" be replaced with "Regional or District Supervisor, as appropriate," in §§ 250.4, Jurisdiction, and 250.5, Functions.

Response—This recommendation was not adopted. The final rule is not the instrument by which authority is delegated within the DOI. Also, §§ 250.4 and 250.5 are too general to refer to Regional or District Supervisor. The authority of the Secretary has generally been delegated to the Director with respect to OCS operations. Regional Directors, Regional Supervisors, and District Supervisors (all of whom have responsibilities under the regulations in this part) exercise the Director's authority through further specific delegations.

Comment—It was recommended that the jurisdiction of the Department of Transportation (DOT) with respect to the transportation of oil and gas to shore be recognized and stated in § 250.4.

Response—This recommendation has not been adopted. The jurisdiction addressed in § 250.4 is MMS's jurisdiction. The MMS recognizes the responsibilities of other Agencies in this area, including EPA's, USCG's, and DOT's. However, it would be inappropriate for MMS to address the jurisdictions of other Agencies in this rule. Those other Agencies can best address their respective jurisdictions in their own rules.

Comment—Comments on frequency of inspections in § 250.5 ranged from suggestions that unannounced inspections be conducted at least annually to characterization of the annual announced inspections as arbitrary and wasteful.

Response—Scheduled onsite inspections "at least once a year" are required by the Act. Unannounced inspections are also required under the Act, but when and how often are properly left to the discretion of DOI.

Comment—Recommendations were made that procedures for inspections, standards, forms, recourse by operator, and other pertinent information concerning inspections should be specifically outlined in the regulations.

Response—The MMS recognizes that a degree of flexibility is necessary for an effective inspection program. However, the subject of the inspections is the operating requirements of Part 250. Those requirements are often very specific. Forms used in connection with inspections are adopted pursuant to DOI approval requirements and are made available to lessees and operators. Lessees' and operators' recourse is setout fully in § 250.24, Appeals, general, and in Subpart N, Remedies and Penalties, if a civil penalty is involved.

Comment—A commenter suggested that monthly reports of inspections, specifically addressing environmental regulatory compliance, should be required and made available to the public. It was felt that such reports would build public confidence and understanding.

Response—Consideration is being given to preparation of periodic reports of inspection results which would be available to the public. However, a requirement for such reports need not and has not been included in this rule.

Comment—A number of commenters recommended that "oral orders" be deleted from § 250.6 because such orders are synonymous with "oral approval."

Response—Oral orders are necessary and are different from oral approvals. There are cases where MMS must take the initiative, as in the case where an order to shut in a well or platform must be issued. Oral orders are issued in such cases and are distinguished from oral approvals. For clarity, the provisions governing oral orders and oral approvals have been separated into separate paragraphs (a) and (b) of § 250.6 in the final rule.

Comment—Another commenter suggested that when oral approvals are granted, notice should be provided to those who had expressed a desire to be kept informed.

Response—This suggestion was not adopted. Since oral approvals are subsequently confirmed by written application and approved, those who are normally apprised of written approvals will be informed when the oral approval is confirmed in writing.

Comment—The requirement to confirm oral approvals in writing should have a specific timeframe.

Response—The last sentence of § 250.6, Oral approvals, has been revised to require confirmation of the requested approval by the lessee within 72 hours.

Comment—It was observed that the granting of a right of use and easement may involve offlease sites and should be subject to the same requirements as the initial leasing of tracts; i.e., National Environmental Policy Act (NEPA) requirements, environmental studies, and public review and comment.

Response—It is true that a right of use and easement may be granted for operations at a site off the lease. Although the activity may be located off the lease, the activities usually involve operations so closely related to the lease operations that they will have been embraced by an environmental documentation that was prepared for lease operations. Of course, if that should not be the case, the NEPA procedures already in place would be pursued, as appropriate. Review and comment on any offlease facility would be accomplished to the same extent as any onlease facility; i.e., through review and approval of EP's and DPP's. It should be noted that the rule clarifies that all the requirements of this part are applicable to such offlease facilities.

Comment—One commenter recommended that the regulations require that any lessee as a holder of a right of use and easement not interfere unreasonably with any OCS users.

Response—That requirement is already provided in § 250.40 which states: "The lessee shall not create conditions which will pose unreasonable risk to the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean." Section 250.7(d) requires the holder of a right of use and easement to exercise rights under the right of use and easement in accordance with the requirements of the regulations in Part 250 including § 250.40.

Comment—Section 250.7 requires that a lessee be notified and have an opportunity to comment if a right of use and easement is sought on the lessee's lease. A number of commenters recommended adding a provision that if the lessee fails to respond within 30 days, the lessee is deemed to have

concurred with the granting of the easement. The commenters were of the view that operations should not be held up by a nonresponsive lessee.

Response—The recommended language is not necessary. The response or concurrence of the lessee is not required for the Regional Supervisor to be able to grant a requested right of use and easement.

Comment—A number of commenters recommended that platforms built on rights of use and easement land conform to Subpart I requirements to the same extent as platforms built on leases; i.e., in § 250.7(c) change "may" to "shall."

Response—This recommendation was adopted. There is no reason to distinguish between platforms located on a lease or off a lease. The recommended change from "may" to "shall" was made.

Comment—Numerous comments were received concerning suspensions under § 250.10. Several new reasons for granting suspensions were recommended.

Response—A new § 250.10(a)(3) has been added to specifically allow for suspensions for a reasonable time to enter into a sales contract when good faith efforts have been made to secure such a contract. A new § 250.10(a)(4) has also been added to specifically allow for suspensions to commence drilling operations when a lessee's good faith efforts have been hampered by reasons beyond the lessee's control. Suspensions have been granted for these reasons under the prior regulations even though they were not specifically identified.

Comment—It was recommended that a provision be added for suspensions due to changes in market conditions that impact profitable lease development.

Response—This recommendation was not adopted. Suspensions should not be granted for temporary market fluctuations alone. However, it should be noted that the new criteria concerning inability to secure a sales contract goes to the heart of the problem.

Comment—Comments were submitted which proposed changing the language in § 250.10(b)(i) to state "The lessee has demonstrated gross negligence or serious disregard to compliance with applicable laws, regulations, or provisions of leases or permits." The concern is that failure to comply with a provision could be unintentional and beyond the reasonable control of the lessee and should not be cause for a suspension of operations. Commenters further state that section 5(a)(2)(i)(B) of the Act is explicit with regard to when the Secretary can suspend operations on a lease and failure to comply is not one of the statutory reasons.

Response—The recommendation was not adopted. A suspension or temporary prohibition of any operation or activity may be appropriate to correct the situation regardless whether the violation was intentional or not. Section 5(a)(1) of the Act provides that no permit or lease shall be extended when the suspension or prohibition is the result of gross negligence or a willful violation. It is the obligation of the lessee to be familiar with the requirements under the law, lease, and governing regulations. While section 5(a)(1)(B) of the Act lists certain suspension criteria, section 5(a) also clearly states that the Secretary is not limited to the provisions under this section when approving suspensions.

Comment—A commenter recommended that the Regional Supervisor shall (not may) suspend operations if the criteria in § 250.10(b)(2) "threat of serious, irreparable, or immediate damage to life," are met. At the very least, the regulation should contain criteria for when the Supervisor could allow operations to continue in the face of such threats, e.g., in an extremely serious energy shortage. Another problem identified with this section is with the level of threat (i.e., serious) that has to be shown before a suspension may occur. In addition, the regulation should provide for immediate notice to the affected State of any suspension, any request for suspension, or any report of a situation which results in consideration of a suspension. Finally, the Secretary should be required to take action within 5 days of learning of any situation which may warrant suspension and immediately where serious harm is threatened.

Response—The regulation gives the Regional Supervisor flexibility to review the degree of threat involved and to take appropriate action in a timely manner which may or may not be in the form of a suspension. All factors would be taken into consideration when making this final decision. It is not necessary to immediately notify the affected State(s) of every suspension, request for a suspension, and situation where consideration is given to directing a suspension.

Comment—A number of commenters suggested adding to § 250.10(b)(6) the following "If any of these permits preclude drilling, then a suspension of operations can be granted without having a commercially producible well." It was felt that the situation now exists where lessees cannot economically develop discovered reserves in a timely manner, especially those in 900- to 1300-foot water depths. Further, with the dramatic decline in oil prices in 1986, these reserves may not be profitable to develop.

Response—The recommendation was not adopted. The addition of the suggested language would not alter MMS's ability to approve a suspension in the absence of a well capable of producing in paying quantities. As proposed in paragraph (d), a well of this type will be required only when approving a suspension of production (SOP) under paragraph (a). Further, a suspension will not be approved based solely on the profitability of lease development. Whether a venture is economical or not is a risk the lessee assumes.

Comment—Section 250.10(b)(6) criteria should include delays due to administrative or judicial challenges or appeals as well as permits or consents.

Response—The recommendation has been adopted and the rule has been so amended.

Comment—Several commenters recommended adding a clause in § 250.10(b)(6) for a suspension for an inordinate delay whenever such delay halts activities for more than 6 months.

Response—The recommendation was not adopted. There may be situations where more than 6 months might reasonably be required for the processing of a permit application. Each situation will be judged on its merits.

Comment—Several commenters suggested that a suspension should also be available in § 250.10(b) when a lessee can show that it is uneconomic for a well to produce at current market prices. The commenters felt temporary market conditions could result in the premature plugging and abandonment of a well.

Response—A new § 250.10(a)(5) has been added to cover producing wells. Premature abandonment of producing wells and loss of recoverable resources should be avoided. Similar relief was granted by DOI in 1986 for both onshore and offshore oil and gas leases.

Comment—A new paragraph was suggested to authorize suspensions when judicial decrees prohibit or delay lease activity.

Response—A new paragraph (b)(7) has been added to § 250.10.

Comment—A commenter suggested a new paragraph be added to § 250.10 to authorize suspension for "any other good cause shown." The commenter felt this was necessary in situations such as the unforeseen rapid fall in prices.

Response—This recommendation was not adopted. Inclusion of this language would render the rest of the section meaningless; there would be no need to

list the conditions under which suspensions could be approved. The phrase "any other good cause shown" is too broad and open to many interpretations. Further, as already discussed, poor economic conditions will not be considered as the sole reason for granting a suspension. It is in the national interest to have exploration and development continue to assure future domestic energy sources.

Comment—Numerous commenters objected to the use of meters in § 250.10(c) in lieu of feet.

Response—The use of the term "meters" is retained. The National Oceanic and Atmospheric Administration (NOAA) bathymetric maps are prepared in meters. The MMS has adopted this system of measurement for consistency with NOAA and the international system of measurement.

Comment—Several commenters felt that the phrase in § 250.10(c) concerning suspensions not exceeding a total of 5 years was redundant with § 250.10(e) which limits suspensions to "periods of time each of which shall not exceed 5 years."

Response—The provisions are not redundant. Paragraph (c) suspensions are limited to a total of 5 years no matter how many suspensions are granted within the 5-year period. Paragraph (e) provides that for all other types of suspensions no one suspension can be granted for more than 5 years, but there is no limit on the total number of suspensions or years.

Comment—It was commented that the requirement for a producible well in § 250.10(d) could preempt a progressive evolution of 3D geophysical technology that offers a significant contribution to cost-efficient petroleum exploration and exploitation and, therefore, contributes to national energy security. The commenters suggest that the rules allow for suspension of operations on tracts prior to drilling even if that suspension would extend the initial lease term.

Response—The suggestion was not adopted. The main mechanism for extending the term of a lease in order for it to be developed and placed on production is an SOP. Before a suspension which would extend a lease beyond the primary term will be considered, the lessee must make the commitment to develop and produce. This cannot be accomplished until oil or gas has been discovered in paying quantities through the drilling of a well(s). At this time, the technology of 3D geophysical exploration has not reached the point where it can be substituted for the evidence obtained by drilling a well.

Comment—Several commenters proposed eliminating the requirement to have a well capable of producing in paying quantities in accordance with § 250.11 when requesting a suspension in § 250.10(a). The commenters felt that additional flexibility is needed to grant a suspension to encourage expeditious exploration and development of a lease under unusual circumstances.

Response—Section 250.10(a) allows for the granting of suspensions to facilitate proper development of a lease and to allow for the construction of or negotiations for use of transportation facilities. The intent of this section is to allow a lessee additional time, after a discovery has been made, to complete development and place a lease on production. If a discovery in paying quantities has not been made, an SOP under paragraph (a) is not in order. The remaining provisions in § 250.10 for granting a suspension of operations do not require the existence of a well capable of producing in paying quantities.

Comment—It was suggested that § 250.10(d) was repetitious because if it is determined that a suspension is necessary to facilitate proper development or to allow for construction or negotiation for transportation facilities, it would seemingly be as a result of a well being drilled and a determination having been made that the well is producible. Certainly no lessee would develop a lease and construct or negotiate for transportation facilities if a producible well has not been drilled. The commenters, therefore, felt that paragraph (d) was not required since the conditions which need to be met in order for a suspension to be issued would by their nature involve the drilling of a well and its producibility.

Response—Section 250.10(d) is not redundant. In the absence of paragraph (d) a lessee might request a suspension for a lease with a well that discovered hydrocarbons but not in paying quantities, as required in (d). Paragraph (d) clearly states the requirement for a producible well which has long been the policy of DOI, rather than rely on the implication of other provisions.

Comment—Several sections from the prior rules concerning suspensions were inadvertently omitted from the proposal.

Response—An explanation of what is required of a lessee after submittal of a site-specific study concerning hazards has been added as § 250.10(h)(2). It is the same language as the prior § 250.12(e)(2). Also, the prior paragraphs (d)(2) and (d)(3) in § 250.12 were omitted from the proposal; therefore, two new paragraphs (j) and (k) have been added to cover termination of a suspension.

Comment—A number of commenters recommended that § 250.11 concerning determinations of producibility should be eliminated. Since such determinations are only relevant to the granting of SOP's, the request for an SOP should in and of itself be sufficient evidence of the commercial viability of a lease. Lessees would not expend time and money on a lease that showed no promise of commercial production.

Response—This recommendation was not adopted. A request for an SOP does not serve the same purpose as a determination of producibility. The determination provides assurance that an SOP, if otherwise warranted by the lessee's commitment to develop and initiate production relates to a lease for which some evidence of potential for future production has been established.

Comment—It was commented that determinations of producibility should not be obtained at the lessee's option but should be required on a case-by-case basis. It was thought this could help MMS perform its obligations.

Response—This suggestion was not adopted. The MMS currently receives all log, core, test, and production data, along with the Well (Re) Completion Report (MMS Form 330), separate and apart from the request for determination of producibility. Therefore, reliance is not placed totally on the request for data or information, regulatory, or lease evaluation purposes. The determination of producibility primarily serves to trigger changing of the lease from rental to minimum royalty status and as a basis for the approval of an SOP when requested to extend the lease beyond the primary term. The rule permits the lessee to seek a determination of producibility for these purposes and will not impair MMS's performance of its obligations.

Comment—Several commenters felt that the bases for determining that a well is producible should not be limited to those listed but should include paragraph (2) of OCS Order No. 4 that allows a determination based on "sound log-interpretation techniques * * * even though the well might not qualify" under the listed criteria.

Response—The suggestion was not adopted. It is true that additional well tests may be required in some instances in order to establish producibility. However, the specific requirements and alternatives in § 250.11(b) are intended to ensure that any well qualified as producible by the application of this criteria (without the benefit of a well test) would unquestionably produce in paying quantities if tested. If the requirements are not met, then an actual

test is necessary to establish producibility. Also, if a lease cannot qualify as producible on the basis of test or log data from a zone encountered in an existing well drilled on the lease, the drilling of additional wells might be necessary if the lessee wishes to qualify the lease as producible for purposes of obtaining an SOP beyond the primary term. However, it is the prerogative of the lessee to decide whether or not to drill such additional wells in an attempt to obtain an SOP. In any event, during the primary term, the lessee should be encouraged to run a test on any encountered sands which are evaluated as producible but which will not meet the specific requirements or criteria in § 250.11(b). Such zones should necessarily be tested to establish producibility before abandonment of the bore hole if the possibility exists that the lessee may later wish to obtain an SOP to continue a lease beyond the primary term.

Comment—It was questioned whether the requirements of paragraph (b) in § 250.11 were to be used individually or collectively as bases for a determination of producibility.

Response—The rule has been amended to add the word "collectively" to § 250.11(b).

Comment—A comment was submitted to delete the requirement for a minimum of 15 feet of producible sand in one section on the grounds that the height (thickness) of the sand has very little to do with the producibility of the sand, does not consider downdip reserve potential or reservoir characteristics, and does not consider everchanging industry economics. Another commenter suggested that the words "which appears to be water-saturated" be deleted from the first sentence in § 250.11(b)(1) on the basis that all reservoir rocks are to some extent water-saturated. Therefore, it would be impossible to identify a producible sand section which is not water-saturated.

Response—The first suggestion has been adopted to allow a less than 15-foot section based on approval of the District Supervisor. The second suggestion has not been adopted. The intent of the section is to identify 15 net-feet of sand interval in the same reservoir or sand body which will produce hydrocarbons rather than water. While this language may be somewhat imprecise, it is recognized oil field terminology which has served well as part of the GOM OCS Order No. 4.

Comment—Commenters questioned the requirement of a gamma-ray log deflection of at least 70 percent. Suggestions included a decrease to 40 percent or to say 70 percent or less of the maximum deflection.

Response—The rule has not been changed. The gamma-ray log deflection requirement of 70 percent is a substitute for a negative 20 millivolt spontaneous potential (SP) deflection, in cases where the mud salinity is such that the SP current is suppressed or not developed. The formation water might also be too "fresh." The gamma-ray deflection from the shale base line is not a mathematically perfect indication of formation lithology. A deflection of 70 percent is used as a minimum figure in the absence of a test. It is recognized that lesser percentages may in some cases be productive at commercial rates. However, the MMS should not have the burden of identifying those productive intervals which will produce with less than 70 percent deflection. In such questionable cases, the lessee should test the well in lieu of reliance on log parameters.

Comment—It was suggested to change the true resistivity ratio of the producible section to the nearest clean water-bearing sand of at least 5:1 to 3:1. The concern is that variable parameters and industry practice would be better reflected by the lower ratio.

Response—The suggested change was not adopted. This provision has been utilized in the GOM OCS Region since 1969 and has worked well. Further depending upon how silty and fine grained a sand may be and upon its porosity and permeability, a true resistivity ratio of 3:1 may or may not indicate producibility and therefore has not been adopted.

Comment—A new paragraph was suggested to be added to § 250.11(b)(l) to read: "A log response analogous to the same or similar horizon in a lease in the near vicinity which has proven to be capable of producing in paying quantities." The concern is that some sands have been found to be commercial which do not meet the listed criteria.

Response—This suggestion has not been adopted. While some sands may produce, many others do not. Additionally, if there is a close-enough producer nearby to apply the log parameters unconditionally, then a development, not exploration situation exists, and the well should be completed to allow the well to be tested through casing.

Comment—Comments were received on § 250.11(b)(2) suggesting evidence that an attempt was made to obtain a porosity log be sufficient in cases where a porosity log cannot be obtained.

Response—This suggestion has not been adopted. The log indicating porosity is vital to the determination of producibility and, in many cases, is run simultaneously with the induction log. The MMS has been somewhat flexible in the past (and certainly would continue to be so) in accepting a Thermal Decay Time Log, or a through-pipe neutron log to meet this requirement. Without a production test, the lessee must show well data supporting a producible section.

Comment—It was commented the required evidence of sidewall core analysis be changed from "is capable of producing oil or gas" to "contains rock that is petrophysically capable of producing oil or gas." The concern is that sidewall cores are often not definitive in identifying water-content because of flushing, etc.

Response—This suggestion has not been adopted. While it is true that the cores are often flushed or the hydrocarbons lost, this is taken into account in evaluation. The cores, as well as the sampling, in § 250.11(b)(4) are pieces of evidence that are requested an operator attempt to obtain. A request has never been denied solely on the grounds of "wet cores."

Comment—It was suggested that "or evidence that an attempt was made to obtain such tests" in § 250.11(b)(4) be replaced with "which indicated that the section is capable of producing oil and gas" on the basis that a multiformation test or mud-log analysis per se does not constitute producibility, nor does an attempt to obtain such tests.

Response—The "evidence" phrase has not been deleted. The intent of paragraph (b) is that the lessee be required to meet all criteria collectively; i.e., the lessee must meet the specific requirements in § 250.11(b)(1) and (b)(2) and must at least attempt to obtain sidewall cores and a wireline formation test and/or mud-logging analysis, as required by paragraphs (b)(3) and (b)(4). The substantiating data provided by paragraphs (b)(3) and (b)(4) are considered highly desirable in making a determination of producibility but are not deemed essential, provided the well is clearly producible on the basis of an analysis of those logs required by § 250.11(b)(1) and (b)(2). However, the suggestion to require that if a wireline formation test and/or mud-logging analysis is successfully obtained, such data must establish that the well is capable of producing oil and gas as a criteria for determining producibility has been adopted. Therefore, § 250.11(b)(4) has been reworded as follows:

(4) A wireline formation test and/or mud-logging analysis which indicates that the section is capable of producing oil or gas or

evidence that an attempt was made to obtain such tests.

Comment—It was commented that § 250.12, Cancellation of leases, should provide that the Secretary "shall" rather than "may" cancel a lease based on the criteria contained in this section. The commenters believe that the itemized conditions for cancellation are sufficiently serious that the authority should be exercised whenever such conditions exist. Further, the commenters suggest the addition of a provision specifying that a lessee shall not be entitled to compensation when a lease expires or is cancelled where the owner of a producing lease fails to comply with a provision of the Act, the lease, or regulations issued under the Act.

Response—The recommendations were not adopted. The Secretary should exercise discretion in the cancellation of leases. The ultimate enforcement action, lease cancellation, should not be a mechanical process. It is not always in the national interest to cancel a lease, even though the criteria for cancellation are present. The Act uses the word "may" in describing the Secretary's authority to cancel leases. The rule provides that no compensation is due a lessee when a producing lease is cancelled for a willful and knowing violation of the law, lease, or regulations.

Comment—It was suggested that § 250.12 could allow serious harm to continue without action being taken, and that the rule is very open-ended. The commenters feel it should specify that harm must be reduced to the point where marine life is not threatened and that this reduction must take place before serious harm occurs. Also, a threat of serious harm or damage should not be permitted to continue for any period.

Response—The suggestion has not been adopted. The rule does not provide for continued operations which could harm the environment. The suspension imposed is for the purpose of suspending the activity which was threatening or causing serious harm or damage to life, property, other mineral deposits, or the marine, coastal, or human environment. The language of the rule repeats the language of the Act.

Comment—It was suggested that a lessee should not risk losing a lease through cancellation due to the action or inaction of a regulatory agency that prohibits drilling. During such time, a lease should be tolled and no rental owed except royalty on existing wells.

Response—By definition, a producing lease term cannot be tolled while production continues. Once a lease enters minimum royalty status, rental is normally no longer due. In § 250.12(c)(1)(i), the term of the lease can be extended 5 years, and the lessee shall be compensated pursuant to § 250.12(e) when the lease is cancelled. This is adequate relief when the conditions in § 250.12(c)(1)(i) apply. When the conditions in paragraph (d)(1) apply, the lease is not extended and the lessee is not compensated in any way. This is fair since the lessee should have been familiar with the requirements of the State's Coastal Zone Management (CZM) program before submitting a DPP.

Comment—Several commenters recommended that § 250.13, which provides for keeping a lease in effect if production, drilling, or well reworking occurs within 90 days, be changed to 180 days. It was claimed that this is especially needed in the Arctic because of environmental and regulatory constraints. In addition, it was suggested that the criteria used for allowing 180 days instead of 90 days between drilling for a lease beyond its primary term should be "interest of conservation, prevention of waste, and the protection of correlative rights." Such criteria would allow more discretion, would be consistent with proposed MUA's, and are more likely reasons for lease extension.

Response—The comment has been adopted. In most instances, 90 days have been adequate. Under the new rule, the Director has discretion in § 250.13(b) to extend time to 180 days or beyond where environmental conditions warrant and it is in the national interest and in the interest of conservation, prevention of waste, and the protection of correlative rights.

Comment—Several commenters suggested in § 250.13(b) which authorizes the Director to extend 90 days to 180 days, between production, drilling, or well-reworking, that "Director" be changed to "Regional or District Supervisor," as appropriate.

Response—The rule has not been changed. This decision should be made by the Director to assure consistency and equity in the application of the policy.

Comment—Several comments were submitted concerning the requirement for a storage agreement and the payment of a storage fee or rental. It was recommended to delete § 250.14(b)(2) in its entirety, because if left intact, the MMS would have the lessee pay storage on reinjection of gas—a process inherent to the production process and implied in the granting of a lease. It was claimed that lessees should not be required to pay storage or rental if such storage is in the subsurface of a lease owned by that lessee. It was also recommended that royalty payments be made only when reinjected gas is recovered and sold.

Response—The comment has not been adopted. Section 250.14(b)(1) proposes subsurface storage of gas for later commercial benefit only. Paragraph (b)(2) requires a storage agreement and the payment of storage fee or rental for the storage of gas for later commercial benefit. Since such storage is a "use right" other than the production of oil or gas, the requirement for the storage fee or rental remains as proposed. The payment of royalty on gas injected or stored offlease prior to injection does not present payments in the form of a penalty. Under the Act, royalties are due when production is "saved, removed, *or* sold" from the lease.

Comment—It was recommended that the phrase "made up of proportionate amounts of injected or stored gas, and gas original to the reservoir in accordance with a formula approved by the Regional Supervisor," be replaced in § 250.14(c) with the phrase "totally injected or stored gas on which royalties have been paid has been recovered." It was claimed that this would prevent overpayment of royalty in case the amount of gas originally in the reservoir, in which gas is injected or stored, is less than estimated.

Response—This recommendation has not been adopted. The commenter's suggestion would allow full recovery of the stored gas before any royalty from the production of the native gas from the reservoir would be paid. This would delay receipt of royalty revenues by the Government and cause the risk of loss of stored gas to be transferred to the Government. The regulation codifies current practice which has been in effect for many years.

Comment—Numerous commenters recommended revisions to the requirement that royalty be paid on gas stored or reinjected off the lease from which it is produced. The commenters recommended adding a new paragraph on storage on contiguous leases within the same field with same operator, same royalty rates, and same (or approximately the same) lease ownership. It was also recommended that royalty only be paid (on or offlease) when the stored or reinjected gas is sold. It was claimed that gas utilized for these purposes is usually commingled from different leases and reservoirs, and to avoid the resultant problems, the rule should permit the leases to be operated together.

Response—The revisions have not been adopted. Unitization under Subpart M should be an adequate solution to the potential problems cited by the commenters. Therefore, the phrase "or unit" has been inserted after the word "lease" in the first sentence of § 250.14(c).

Comment—Commenters recommended that the following sentence be added to § 250.14(c):

While gas remains in storage, the lessee will have the same recourse under paragraph 250.10 and paragraph 250.13 to maintain the lease in force as any lessee producing naturally occurring hydrocarbons, whether royalty is due or not.

Response—The recommendation has not been adopted as it does not appear to be permissible under section 8(b)(2)(B) of the Act.

Comment—Several commenters recommended the lease number and well number requirements be deleted from platform identification as required in § 250.15.

Response—This recommendation was adopted. The lease number and well numbers are not necessary for the platform identification sign. Therefore, the requirement has been deleted.

Comment—It was suggested that the platform identification requirement for the area designation based on OCS Official Protraction Diagrams be deleted because it provides no assistance for helicopter navigation.

Response—The recommendation was not adopted. Platform identification is not only for the benefit of helicopter navigation but also for vessels. It not only aids MMS but also the other traffic in the area. In addition, all reports are facilitated by including area designations.

Comment—It was suggested to change the criteria in § 250.15 for allowing signs of 3-inch height from smaller facilities to those without helicopter landing facilities.

Response—This recommendation was adopted. The rule has been so changed.

Comment—A time limit of 90 days for request of reimbursement for food, transportation, and lodging was suggested to be added to § 250.21.

Response—A 90-day time limit for requests for reimbursement has been added as a reasonable administrative requirement.

Comment—Several commenters suggested adding the following to § 250.17, Information and forms:

Computer generated forms which are equal in size readability and paper quality, and which arrange the data in identical format, may be submitted in lieu of the forms available from the Regional or District Supervisor.

Response—This recommendation was adopted. The sentence has been added at the end of § 250.17(a).

Comment—Several commenters questioned various aspects of the release of proprietary data in § 250.18. It was recommended that determinations of producibility not be made public and that data should not be released at the end of the proprietary term if the tract is not then under lease.

Response—These recommendations were not adopted. Determinations of producibility are made by MMS and, therefore, have been and should continue to be public information. This issue has been addressed in several appeals decisions by the Director. The Solicitor has also concluded that determinations of producibility are governmental decisions available to the public. It should be noted that the geological and geophysical (G&G) data and information which are submitted by lessees and which form the basis for those determinations are protected from release to the public pursuant to the regulations. The lessee evaluated the information and based its action or inaction on that evaluation. Thus, neither the lessee nor the lessor would benefit from continued protection.

Comment—A commenter questioned whether bathymetry maps, discussions of geohazards, and specific and general geology will be discussed in EP's in view of the prohibitions in § 250.18.

Response—To the extent that material contained in an EP falls within categories for which protection from release to the public is provided in § 250.18, such material will be protected within the terms of that section.

Comment—Numerous commenters recommended different methods or times for determining the time period for protection. A number of commenters recommended that the 10-year period of protection be changed to twice the primary lease term because deep water leases have 10-year lease terms, and the period of protection should be correspondingly longer.

Response—This recommendation was not adopted. It does not necessarily follow that longer primary terms indicate a need for longer periods of protection for data and information. The purpose for protecting G&G data and information is to provide lessees who acquired such data and information with the possible commercial benefit of such data and information insofar as it is relevant to subsequent sales. This does not necessarily correspond to the length of the primary term of other leases.

Comment—Numerous commenters suggested that the 2-year period of protection be extended by 3 years and/or by periods of time during which drilling is restricted or suspensions are in effect. They also recommended all G&G data and information from leases issued prior to June 11, 1976, be exempt from disclosure as they are under section 3.1 of OCS Order No. 12.

Response—The 2-year provision has been supplemented by a provision based on occurrence of a subsequent sale within 50 miles of the well or for leases in their primary term. This change incorporates an amendment to prior regulations which was published as a final rule in the **Federal Register** on April 22, 1987 (52 FR 13235). Provision has also been made for protection for the period of the primary term as that term may be extended on the basis of certain suspensions of operations. With respect to pre-June 11, 1976, leases, the commenters are mistaken that OCS Order No. 12 provided protection from release of all G&G data and information. The Order by its own terms provided protection from release "Except as provided in 30 CFR 250.3." Prior § 250.3 provided limited periods of protection, and there is no reason to change this.

Comment—High resolution data submitted in compliance with lease stipulations concerning protection of the environment are released 60 days after submittal in § 250.18(c). It was recommended that these data not be released until several years thereafter.

Response—This recommendation was not adopted. Section 250.18(c) is not a change from prior rules, and there is no reason to change the policy.

Comment—Several commenters indicated that data and information on Form MMS–330 were available upon commencement of production under OCS Order No. 12, but under the proposed rule, such data and information would be withheld for 10 years. It was recommended that the rule not be changed from OCS Order No. 12.

Response—There appears to be no particular reason for departing from OCS Order No. 12 as to the specific items to be afforded protection. Therefore, the same items will continue to be protected.

Comment—A number of commenters suggested that § 250.18(d) be amended to reflect the requirements of OCS Order No. 12 whereby information identified in the paragraph would be protected until production is commenced (except for "Summary of Porous Zones" and "Geologic Markers") or after 5 years if production has not commenced (except for "Summary of Porous Zones" and Geologic Markers").

Response—The reference in § 250.18(d) should have been to

paragraph (b) of that section and not (a). Proposed paragraph (b) provided for a 2-year term. However, it appears that the commercial value of the protected information relates essentially to its potential use in a subsequent sale in the area. That being so, any term of protection should be related to subsequent sales as it is in the final rule.

Comment—It was suggested that data and information obtained from beneath unleased land as a result of a well deviation *which has not been approved by the Regional Supervisor* shall be available to the public.

Response—This recommendation was adopted. The phrase has been added to § 250.18(f).

Comment—A commenter suggested that MMS and USCG should coordinate and that both Agencies should use the same report form for accident reporting in § 250.19.

Response—This recommendation was not adopted. The MMS and USCG do coordinate through an MOU but have different needs relative to accident reporting because of their different areas of responsibility.

Comment—Several commenters indicated that operators of pipelines on rights-of-way are obliged to report "all serious accidents, any death or serious injury, and all fires, explosions, and blowouts * * * to the Regional Supervisor." Such operators must report the same facts to the National Response Center under DOT regulations at 49 CFR 191.5. The commenters believe that one report should be sufficient.

Response—This recommendation was not adopted. Because of its responsibility, MMS needs to have the earliest possible notice of incidents described in § 250.19.

Comment—It was recommended that a requirement be added for the use of BAST in § 250.20, Safe and workmanlike operations, "to detect and control all leaks to prevent the emission of gases and other pollutants into the atmosphere, especially those that pose a danger to personnel and/or the environment."

Response—This recommendation was not adopted. Gas leakage prevention and detection are addressed adequately in the specific operating requirements (see Subparts D, Drilling and H, Production Safety Systems).

Comment—Several commenters suggested that paragraph (c) of § 250.21, Access to facilities, be amended as follows:

The lessee, *subject to availability*, shall, on request, furnish food, quarters, and transportation * * * [Upon request,] thelessee will be reimbursed * * *.

(Underscored to be added; bracketed to be deleted.)

Response—The suggested changes have not been adopted. As to availability, lessees obviously cannot make available that which is not available. As to requests for reimbursement, they are necessary because costs will vary widely and could not be determined in the absence of requests.

Comment—A commenter stated that § 250.22, Best available and safest technologies, is at odds with the Act. The regulations require that a "significant incremental benefit be provided before BAST is required," but the statute require BAST wherever failure of equipment would significantly affect safety, health, or the environment. The commenter also stated that "No systematic analysis has been undertaken to show that these standards and practices [those in Part 250] indeed are BAST."

Response—The language in § 250.22 has been amended to conform more closely to the statute. However, as a practical matter, MMS does systematically monitor and identify BAST, taking the economic feasibility and cost-effectiveness into account. This is largely accomplished through multidisciplinary groups such as Regional Operations Technology Assessment Committees and Regional Technical Working Groups.

Comment—Commenters also requested an amendment to § 250.22(a) whereas the technologies involved must be *demonstrated by OCS lessees and approved by the Regional Supervisor.* The commenters believe that the rule should clarify who determines what is significant and cost-effective and that industry should have a significant role in doing so.

Response—The change is not needed. All BAST requirements will be adopted through rulemaking in which lessees, the public, and other interested parties will have full opportunity to participate.

The final rule also differs from the proposed rule because of two amendments which were made to prior rules after the March 18, 1986, proposal. They are incorporated without substantive changes into this final rule.

On June 25, 1987 (52 FR 23815), MMS published a final rule to require a report of cessation of production when the last well on a lease goes off production. In the absence of the monthly report of operation, this new report is needed to enable MMS to enforce new § 250.13. This requirement is incorporated in the final rule as § 250.23, Report of cessation of production.

Revised requirements relating to conduct of accident investigations were published in the **Federal Register** on June 11, 1987 (52 FR 22305). These new requirements are incorporated in the final rule as § 250.19(c).

Subpart B—Exploration and Development and Production Plans

This subpart combines the provisions at current §§ 250.14, Well spacing, and 250.34, Exploration, development, and production activities, and selected OCS Orders and NTL's.

In general, the new rules combine reporting requirements, eliminate unnecessary and redundant requirements, eliminate descriptions of internal MMS procedures, and simplify format and language.

There were 21 comments received in response to the solicitation. Of those, 13 were received from the oil and gas industry, 4 from States, 3 from Federal Agencies, and 1 from an environmental group. In general, the commenters agreed with proposed changes. However, some specific comments were made and are addressed below. The final rule reflects the changes made after careful consideration of the comments received.

Comment—Some commenters expressed concern that important site-specific environmental information might not be submitted if lessees are authorized to jointly submit information.

Response—The MMS does not share this view. Joint submittals are only authorized for plans in areas with similar environmental conditions. The same detailed environmental information will apply only to leases covered by this plan(s). The intent of the joint submittal option is to facilitate data gathering and report preparation. Reduction in data quality or specificity will not be acceptable.

Comment—Some commenters felt that the requirement for a Development Operations Coordination Document (DOCD) for the western GOM appeared to be an administrative tactic to avoid the congressional exemption from the requirement to submit a Development and Production Plan for the western GOM.

Response—The provision for a DOCD has been retained. The DOCD is required so that MMS approval of proposed development and production activities meets the environmental review requirements of NEPA. Without such notice, MMS would have to conduct environmental reviews for each individual pipeline and platform application and APD. Such a process would be unduly burdensome for MMS,

lessees, and reviewing Federal and State agencies. The DOCD is also necessary for State consistency review pursuant to the CZMA.

Comment—Some commenters objected to the revised definition of preliminary activities allowing seafloor penetrations to depths of 500 feet without an approved plan. They questioned the legality of allowing activities prior to plan approval and objected to the 500-foot depth allowance for such activities. It was also recommended that preliminary activities be exempted only if they do not affect the land and water uses of the coastal zone.

Response—It has always been recognized that certain preliminary activities are necessary in order to develop data and information needed to prepare a plan. Lessees cannot develop comprehensive work plans until preliminary seismic surveys, soil borings, and other site reconnaissance have been performed. This information is particularly important in preparing DPP's. Piles which support offshore production platforms may be driven to depths of 500 feet or more. To properly design offshore structures, it is necessary to perform geotechnical analyses of the supporting sediments. Some of the cores necessary for such analyses must be obtained by drilling to depths of several hundred feet. The ambiguity of the previous requirement (300 feet of unconsolidated sediments or 50 feet of consolidated sediments) has proven troublesome for MMS and lessees. The 500-foot limit is more easily understood and enforced. Soil borings and core holes are unlikely in areas where potentially hazardous accumulations of hydrocarbons are found within 500 feet of the seafloor. Such areas are most unfavorable for installing production platforms. The Regional Supervisor retains the authority to prohibit borings in potentially hazardous areas or to require additional information before boring activities are initiated. The Regional Supervisor must also consider potential effects on the land and water uses of the coastal zone when determining information and notification requirements for preliminary activities.

Comment—Comments were received regarding the provision that the Regional Supervisor may require prior notification of the type, scope, and timing of any survey. It was proposed that language be added to stipulate that prior notification will be required only for exceptional circumstances and that procedures specified in NTL's would cover most surveys. Commenters also questioned when MMS would require prior notification.

Response—The option for the Regional Supervisor to require prior notification before surveys are carried out is necessary to assure that proper consideration has been given to commercial fishing activity, marine wildlife, sea ice, and other concerns. Prior notifications are required under present practices in the Pacific and Alaska OCS Regions and will continue to be required in these Regions. Each Regional Supervisor will be responsible for determining the type of prior notification that is required based on the needs of the area involved.

Comment—Some commenters felt that if a lessee's well spacing program is disapproved, the Regional Supervisor should be required to provide alternative plans with analyses that demonstrate the superiority of the MMS plan.

Response—Sections 250.33(j) and 250.34(m) require the Regional Supervisor to notify the lessee in writing of the reasons for disapproving or requiring modification of a proposed plan. This notification will specifically advise the lessee of the conditions that must be met for plan approval.

Comment—A commenter objected to the language "minimization of unreasonable risk" in § 250.32 because risks should be avoided, and risks deemed significant should be predicted.

Response—We concur that the proposed language was confusing. The provision now reads "minimization of risk to the environment, and unreasonable interference with other uses of the OCS."

Comment—Several commenters felt that the provision which pertains to wells which could intersect offset properties should apply only to production wells completed within 500 feet of the offset property and that only directional survey information should be released for such wells.

Response—Section 250.32(b) provides lessee with prior notice that special measures may be required with respect to wells that could intersect or drain offset property. Lessees must not be permitted to drill exploratory wells into adjacent State or Federal properties (leased or unleased) and obtain information on such properties unless prior arrangements are made to protect the rights of the adjacent lessee, the Federal Government, and the States (where applicable). A specific provision has been added to Subpart K (§ 250.171) requiring the Regional Supervisor's approval to produce wells in the GOM and Alaska OCS Regions in which the completed interval is less than 500 feet from a lease line. In other Regions, decisions regarding allowable locations for wells near lease lines will be made on a case-by-case basis. The last sentence of § 250.32, which included examples of special measures the Regional Supervisor may require to protect offsetting leases, has been deleted because each case must be considered separately.

Comment—One commenter suggested that lessees retain the option of submitting environmental information as an attendant Environmental Report.

Response—Lessees may continue to submit the necessary information in more than one volume. Each volume would be considered a part of a plan rather than a separate Environmental Report. The intent is to eliminate unnecessary duplication, not to unduly limit a lessee's options regarding the preparation or format for submitting the required information. Under existing rules, certain information submitted is approved by MMS while other information, such as that contained in an Environmental Report, is submitted as supporting information. This rule is not intended to change the scope of an MMS approval. Sections 250.33 and 250.34 were revised and restructured to clearly identify the portions of a plan which will be subject to specific approval and the portions which will be received as supporting information. However, note that even though the supporting information is not subject to specific MMS approval, MMS can disapprove a plan based on inadequate or inaccurate supporting information.

Comment—Several commenters suggested that the EP include a tentative timetable for the first well only, not all wells proposed in the plan.

Response—No change has been made in this paragraph. It is recognized that there is a high degree of uncertainty involved in projecting future wells; the information is necessary to give plan reviewers a general idea of the potential frequency and duration of drilling activities pursuant to the plan. The information also assists MMS in preparing a review under NEPA which will not require extensive supplementation at a later date.

Comment—One commenter felt that air emissions might be underestimated because lessees need only describe the type of drilling unit to be used and not the specific drilling unit.

Response—Recognizing this possibility, the proposed and final rules require a worst case emissions estimate when a specific drilling unit is not identified in the plan.

Comment—Several commenters recommended deletion of the requirements for information on new or unusual technology to be employed in the proposed operation. The respondents are concerned about the proprietary nature of some new technologies and the large volume of information that might have to be submitted.

Response—This recommendation was not adopted. Information on new technology is necessary for MMS to properly assess the proposed activity and make environmental determinations pursuant to NEPA. The Regional Supervisor can provide guidance as to what constitutes new or unusual technology in the Region. However, the provision has been moved from being part of the plan to being part of the accompanying information. Language has also been included which requires the lessee to identify portions of the information believed to be exempt from disclosure pursuant to the Freedom of Information Act. To allow for transmittal of plan copies to reviewers, the lessee will be required to include a written discussion of the general subject matter of the deleted portions in such a manner as to protect its proprietary nature.

Comment—Comments were received objecting to the requirement for projected bottomhole locations in § 250.33(a)(4) (now § 250.33(a)(3)).

Response—The requirement has been deleted and the word "appropriate" has been corrected to "approximate."

Comment—Comments were submitted concerning the required structure contour maps drawn to the top of each prospective hydrocarbon accumulation. They recommended submission of a map of a representative prospective hydrocarbon accumulation.

Response—This recommendation was not adopted. The MMS believes that maps to the top of each accumulation are necessary. Structure maps provide detailed geologic data on the structure that is to be drilled. It is necessary to have the same maps that the lessee is using to define the parameters of its drilling program and not a representative map that would limit MMS's understanding of the prospect.

Comment—A commenter recommended adding "if such lines are available" in § 250.33(a)(5)(ii) concerning submission of seismic lines at or near the primary well locations because the information is not available if it is not needed.

Response—This recommendation was not adopted. While MMS recognizes that seismic lines may not always be available that intersect "at" the location, lines should be available which intersect "at or near" the location. At a minimum, a lessee should submit the seismic lines which were used to select well locations.

Comment—Comments recommended deletion of the requirement for submission of specific geologic data and information under § 250.33(a)(5) (i) through (vi) as duplicative and unnecessary for all wells.

Response—This recommendation was not adopted. While detailed comprehensive information is needed in frontier areas primarily, even in developed areas significant amounts of information are needed to evaluate a plan. The final rule allows the Regional Supervisor to inform the lessee what specific information is needed. If the information is unavailable because the lessee did not feel a need to obtain it, the Regional Supervisor can consider that fact while evaluating the work proposed in a plan.

Comment—A commenter objected to the submittal of interpreted or analyzed data which is subjective analytical work that might later be found to be inaccurate. Initial analyses and interpretations prepared prior to drilling are subject to reevaluation, therefore, submittals of G&G data should be limited to processed data.

Response—The suggested change was not adopted. If interpreted or analyzed data were eliminated from an EP, very little would remain because much of the information is interpreted. While recognizing that G&G interpretations are subject to change, the submittal of interpreted information with a plan gives MMS the most current reasoning behind the lessee's decision to drill a well. The lessee could state that the interpretations may change after additional data are obtained from the well(s).

Comment—Comments were received that the requirement for a bathymetry map in § 250.33(a)(5)(viii) (now § 250.33(b)(1)(viii)) is redundant with the § 250.51(d) requirement for a submittal of a hazards survey. Also, the requirement for analysis of geological hazards is redundant with § 250.51(d).

Response—It is recognized that where previous hazards surveys have been run and reported and other data are available, an additional survey may not be needed. The bathymetry map required in this section is not intended for the same purpose as the one required in § 250.51(d). A bathymetry map is needed to show the water depths and seafloor topography at each well site as a general overview of the area for approval of an EP. Accurate bathymetry maps are available from multiple sources, not limited to those generated during the hazards survey. However, it would be preferable that, if a hazards survey has been conducted, the bathymetry map be generated during the survey. The requirement for a shallow hazards survey has been clarified in this subpart because geologic hazards must be addressed in EP's. The requirement for a shallow hazards survey has been deleted from § 250.51(d).

Comment—There was concern expressed that reference to an approved Oil Spill Contingency Plan (OSCP) may not be satisfactory for a new plan and that this practice might make it difficult for the USCG to perform an OSCP review. There was also concern that State agencies have current OSCP information.

Response—No change was made in the final rule. The MMS believes that the commenter's concerns are adequately addressed by the rules as proposed. If an approved OSCP does not adequately cover the proposed activity, the Regional Supervisor will not approve the proposed plan until the OSCP has been updated. As required by § 250.42, all OSCP's must be reviewed and updated annually. All annual or interim updates that accompany proposed plans are transmitted to the USCG for comment. All approved OSCP's and revisions are also routinely provided to the affected States.

Comment—Several commenters requested deletion of the requirement that information on drilling fluid components and projected discharge rates be included in EP's because such discharges are regulated by the EPA and the information could be redundant.

Response—This recommendation was not adopted. Drilling fluid information is necessary for MMS's personnel performing NEPA reviews of the proposed project and for States conducting coastal zone consistency reviews. Discharges authorized by EPA are not always specific to the project. Any attempt to evaluate an exploratory drilling proposal without information on a major operational and environmental issue, such as drilling fluids to be used, is likely to result in avoidable and unnecessary delays. The same reasoning applies to information required in DPP's under § 250.34(b)(8)(ii).

Comment—Commenters felt the explanation of information required in § 250.33(a)(10) (now § 250.33(b)(7)), concerning onshore facilities and traffic, was confusing.

Response—The requirement has been rewritten to better describe the needed information.

Comment—Several commenters questioned the criteria that would be used to determine when an onshore facility is being significantly expanded under §§ 250.33(a)(11) and 250.34(a)(10)(iv) (now §§ 250.33(b)(8) and 250.34(b)(8)(iv)).

Response—Because this provision was intended to exempt established support facilities in the western GOM from the information submission requirement, the section has been revised to require inclusion of the information only in plans for areas other than the western GOM. The phrase "new or significantly expanded" has been deleted.

Comment—Several commenters felt that submission of historic weather and oceanographic data and certain types of environmental data could be repetitive, especially in the GOM.

Response—Lessees are authorized to incorporate by reference previously submitted information under § 250.33(c). Furthermore, the Regional Director can limit the information requirements under § 250.33(d) if the information is found to be unnecessarily repetitive.

Comment—Several commenters felt that the cultural survey requirements should be reduced and/or the results should not be required in the discussion of archaeological and cultural resources.

Response—Decisions regarding cultural resource survey and report requirements are made by the Regional Supervisor on a case-by-case basis. The MMS, in consultation with affected States, continually reviews policies and procedures for imposing such requirements in an effort to limit surveys to those areas where cultural resources are most likely to be impacted. To the extent that a survey is required, the results should be included in the plan.

Comment—Several commenters indicated that an assessment of the cumulative effects expected to result from the proposed activities would be unduly burdensome and that such assessments would duplicate information already included in environmental documents.

Response—Because assessments of cumulative impacts are required elements of the NEPA review process, this information is necessary for completion of MMS's environmental assessment of the project. As indicated in § 250.33(c), lessees may fulfill this requirement by referencing Environmental Impact Statements (EIS) and other environmental documents, as appropriate.

Comment—Numerous comments were received on the air emissions sections of the proposed rules.

Response—No changes were proposed and none are being made in these sections pending completion of the negotiated rulemaking process now underway. These comments have been provided to MMS's personnel working with the negotiated rulemaking process.

Comment—Objections were received to the provision allowing lessees to incorporate documents by reference, indicating that such practices could impede reviewers in State agencies.

Response—The intent of the subject provision is to minimize redundant filings. Any documents submitted to MMS in support of previous plans or prepared by MMS, such as EIS's or other widely referenced documents, should have been made available previously to the reviewers in State agencies. However, recognizing the possibility that documents that are not readily available might be incorporated, a phrase has been added requiring that documents incorporated by reference be readily available to State agencies.

Comment—Several commenters requested a provision to exempt operations adjacent to States without approved CZM plans or the entire GOM from some of the requirements of § 250.33 concerning EP's. Other commenters indicated that the amount of information should not be limited unless all State CZM concerns are satisfied by agreement of the State(s) and not simply after consultation.

Response—This recommendation was not adopted. Rather than identifying specific exemptions, the Regional Director can limit information requirements. Because some States may not have CZM programs, some information may not be needed for operations adjacent to those States. However, the decision on exemptions should be left to the Regional Director after consultation with the State(s). The MMS believes that consultation is adequate because provisions of current laws, regulations, and procedures are sufficient to assure that the Regional Director is fully attentive to State information needs. Unwarranted information reductions would only result in unnecessary delays in satisfying NEPA environmental review requirements and CZM consistency determinations.

Comment—It was requested that the commenting period for affected States be extended beyond 20 days.

Response—The Regional Supervisor is required by the Act to act upon EP's within 30 days of submission. Unless State comments are received in advance of that deadline, they cannot be considered in MMS's environmental assessment or in the Regional Supervisor's approval/disapproval action on the plan. Under some circumstances, the Regional Supervisor may be able to consider comments received after the 20-day commenting deadline but within the 30-day limit imposed by the Act. The language of the final rule has been revised to require that comments be submitted prior to a deadline specified by the Regional Supervisor who will consider State needs, calendar considerations (i.e., weekends and holidays), and the time necessary for incorporating comments in NEPA review documents before establishing deadlines.

Comment—A commenter suggested that the Regional Supervisor be required to disapprove an EP if State CZM concurrence has not been received.

Response—This recommendation was not adopted. The Act requires action on an EP within 30 days. It also prohibits the approval of APD's and other permits until CZMA consistency concurrence requirements are satisfied. This precludes any drilling activity pending completion of the CZMA review.

Comment—It was commented that the entire EP should not have to be resubmitted if modifications are being made to only one section.

Response—Section 250.33(k)(1) provides that only the modified information need be submitted. The same is true for DPP modifications under § 250.34(l)(2).

Comment—Several commenters recommended that the clause "and that the proposed activity cannot be modified to avoid the condition(s)." be added to the end of § 250.33(h)(3) (now § 250.33(i)(3)) so that the plan would not have to be disapproved if the identified problems could be avoided or otherwise mitigated.

Response—This recommendation was adopted. The proposed language is consistent with the Act.

Comment—Another commenter recommended that plans be disapproved if any significant harm would occur or be threatened.

Response—This recommendation was not adopted. Addition of the suggested language would not be consistent with section 5(a)(2)(A)(i) of the Act.

Comment—It was commented that the rules describing the procedures to be followed when EP's need modification or are disapproved were too complicated and confusing.

Response—The final rule has been modified for the purpose of clarifying this situation. A new paragraph (l) has been added to § 250.33 to cover the procedures to be followed when a State

objects to a coastal zone consistency certification.

Comment—One commenter stated that any special survey required under § 250.33(m) (now § 250.33(n)) to ensure safety and environmental protection be justified.

Response—Under the final rule, the Regional Supervisor is to advise the lessee of the reasons why special surveys are necessary. The lessee may appeal such decisions pursuant to § 250.24.

Comment—A commenter proposed limits on the Regional Supervisor's authority to approve plan departures in emergency situations.

Response—These proposed limits were not adopted. The wide range of possible emergencies and the need for full authority to act in emergency situations preclude the specification of limits over the Regional Supervisor's authority to authorize departures from approved plans. Supervisors must be able to act promptly, and as necessary, in emergency situations.

Comment—Commenters suggested that DPP's should include a discussion of proposed drilling and completion programs.

Response—The MMS has adopted the recommendation and added a new § 250.34(b)(6). In addition, proposed §§ 250.34 (a)(2) and (a)(4) through (a)(16) now make up § 250.34(b) of the final rule.

Comment—Several commenters recommended that the description of practices intended to increase ultimate recovery of oil and gas be deleted because such practices cannot be effectively planned until extensive well data have been gathered and production history has been established.

Response—This recommendation was not adopted. Although final planning for secondary and tertiary recovery is normally dependent upon well history and performance data, provisions for gas injection, gas lift, waterflooding, and other procedures for enhancing the effects of natural reservoir energy must be considered in the design of the platform, wells, and production equipment. For some types of reservoirs, maximum recoveries cannot be achieved unless gas reinjection or other procedures are implemented at the outset. If MMS is to fulfill its mandate regarding conservation of resources, it must have some information about enhanced recovery options prior to approval of DPP's.

Comment—A commenter interpreted the rule at proposed § 250.34(a)(5)(iii) (now § 250.34(b)(1)(iii) concerning release of data and information to only require submittal of data and information collected under a lease and not data or information collected prelease. This commenter felt, however, that if data and information obtained under a prelease permit were required to be submitted, they should be covered by Part 251 and not Part 250 of 30 CFR.

Response—The MMS does not share these views. The release of data and information obtained under a prelease permit and submitted to fulfill the requirements of § 250.34 will be governed by the provisions of Part 250 and not those of Part 251. The same is true of data and information submitted in support of an EP under § 250.33.

Comment—It was pointed out that the requirement to provide shallow hazards analysis was redundant with a similar requirement for OCS structures in Subpart I, Platforms and Structures.

Response—The potential for redundancy has been recognized and a sentence added to § 250.34(b)(1)(vii) which provides that the shallow hazards information required for the plan shall be derived from the report for § 250.139.

Comment—Several commenters questioned the requirements under proposed § 250.34(a)(9) concerning environmental data and information.

Response—Section 250.34(b)(8) (proposed § 250.34(a)(9)) has been reformatted. Proposed § 250.34(a)(9)(i) (D) and (E) have been renumbered § 250.34(b)(8) (ii) and (iii). Proposed § 250.34(a)(9)(ii) has been renumbered § 250.34(b)(8)(iv) with the western GOM excluded from the requirement. Proposed § 250.34(a)(9)(iii) has been renumbered § 250.34(b)(8)(v). Furthermore, proposed § 250.34(a)(9)(iii)(A) has been revised to conform with the parallel section on archaeology in § 250.33 for EP's and renumbered § 250.34(b)(8)(v)(A). Section 250.34(a)(9)(iii)(B) has been revised and renumbered § 250.34(b)(8)(v)(B), and a new § 250.34(b)(8)(v)(C) has been added to more explicitly describe information requirements for environmentally sensitive areas. Proposed § 250.34(a)(9)(iii)(E) has been revised to assure that air temperature, visibility, and wave height information are included and renumbered § 250.34(b)(8)(v)(F), and proposed § 250.34(a)(9)(iii)(F) has been revised to assure that commercial fishing, recreation, and shipping are considered and renumbered § 250.34(b)(8)(v)(G).

Comment—One commenter recommended deletion of the requirement in proposed § 250.34(a)(11) to discuss alternatives that were considered during the development of the plan.

Response—The requirement has not been deleted because such a consideration of alternatives is necessary for MMS to prepare the environmental documentation for the proposed activity. Proposed § 250.34(a)(11) is now § 250.34(b)(10).

Comment—One commenter recommended that the requirement for DOCD's applicable to States with approved CZMA plans not be left to the discretion of the Regional Supervisor.

Response—This recommendation was not adopted. Although the Act contains language which excludes GOM OCS leases from the statutory requirement to submit a DPP, the lessee is required to provide data and information to satisfy NEPA and CZMA requirements. Specific requirements can best be determined by the Regional Supervisor in consultation with the States as reflected in a lessee's submittal of a DOCD, as required.

Comment—One commenter requested that coastal resource service areas (CRSA) boards be included with local governments and affected States in receiving DPP's. They further proposed that plans and EIS's be routinely provided to local communities and that specific prior requests for such documents not be required.

Response—These concerns can be addressed under the rule as proposed. Where no formal local governments exist, the Regional Supervisor will assume that CSRA boards will be responsible for local input. Also, local governments can make a single initial request for all plans and EIS's for a planning area. Separate requests for each document are not required.

Comment—Different commenters requested that the 60-day comment period for affected States either be extended or shortened.

Response—Neither recommendation was adopted. Sections 19(b) and 25(g) of the Act specifically limit the comment period to 60 days for plans not requiring an EIS. When an EIS is required, it is important to receive early notice of issues that should be addressed.

Comment—One commenter proposed that the Regional Supervisor only be allowed 45 days after the release of the final EIS or close of the comment period to act on the DPP.

Response—This recommendation was not adopted. The 60-day period is specified by section 25(h) of the Act.

Comment—Comments were received concerning the procedures for resubmittal of modified plans and procedures to follow if a plan is disapproved because CZM consistency has not been received.

Response—Clarifying language contained in existing regulations and

omitted from the proposed rule has been added under § 250.33(l) and 250.34(i)(2).

Subpart C—Pollution Prevention and Control

Subpart C, Pollution Prevention and Control, incorporates requirements from OCS Order No. 7, Pollution Prevention and Control; § 250.43, Pollution and waste disposal; § 250.57, Air quality; § 250.54, Marking of equipment; and portions of OCS Order No. 1, Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects as they relate to the marking of equipment.

Comments were received from 25 commenters, 18 from industry, 4 from States, 2 from Federal Agencies, and 1 from an environmental group.

Generally, the commenters agreed with the proposal; however, certain changes were suggested, some of which were made in the final rule. A discussion of specific comments and MMS responses follow.

Comment—One commenter requested inclusion of a requirement that lessees submit a copy of a valid Certificate of Financial Responsibility (COFR) for pollution liability as required by the USCG.

Response—No change has been made pending completion of a review of the MOU between MMS and the USCG. The collection of COFR's is being considered in this review. Any changes necessitating rulemaking will be proposed for public comment prior to final promulgation.

Comment—Several commenters questioned the ability of lessees to assure that their actions do not adversely affect the public health as required in § 250.40(a).

Response—The MMS recognizes that guarantees cannot be made. However, the intent of this paragraph is to prevent situations in which there is an unreasonable risk to the public health and provide a basis for requiring mitigation if such adverse conditions are created. Therefore, the rule has been changed accordingly.

Comment—One commenter recommended that pollution be defined and prohibited.

Response—Lessees are forbidden to discharge any water pollutants in unauthorized quantities. The language of § 250.40(a) prohibits such practices and has been revised to clarify its intent.

Comment—Numerous commenters indicated that total removal of pollution is not possible and that requiring "immediate corrective action" is not necessary in all cases of pollution.

Response—This recommendation was partially adopted. The MMS recognizes that total removal is not always possible and has changed the language to require that the pollution be removed to the satisfaction of MMS. The MMS will, in accordance with the terms of the MOU, consult with the USCG in making this judgment. It is recognized that corrective action is not always possible and that required actions are to be corrective in nature (e.g., control or removal).

Comment—One commenter indicated that the USCG, not MMS's District Supervisor, would be responsible for modifying corrective actions.

Response—This view fails to recognize the scope of the situations covered by § 250.40(a). Section 250.40(a) applies to all forms of pollution and not just major oil spills. In the event of a major oil spill, the USCG would, in accordance with the MOU's between MMS and USCG, be responsible for containment and cleanup activities. The MMS would be responsible for abating the source of the spill and corrective action to protect personnel and facilities involved in the abatement operation. For minor spills and other forms of pollution, MMS is authorized to take prompt action to assure a proper response.

Comment—Several commenters felt that § 250.40(a)(2) implied that failure by the lessee to control pollution was a foregone conclusion.

Response—The MMS has revised the first sentence of the section to read "If the lessee fails to control and remove the pollution" in order to eliminate the implications raised by the commenters. Also, the phrase "at the expense of the lessee" was inadvertently left out of the paragraph and has been returned to the final rule to clarify that the lessee will have to pay for removal activities carried out by the Government if the lessee fails to control and remove the pollution.

Comment—Numerous commenters requested deletion of MMS's regulation of drilling fluid discharge because it is an EPA responsibility.

Response—The MMS recognizes the potential for redundancy between EPA and MMS requirements in this area but also realizes the possibility of gaps in exercise of responsibilities. Until the MOU between MMS and EPA has been fully implemented, MMS believes the redundancy is unavoidable. The MMS's Offshore Minerals Management program is founded upon effective environmental protection practices and procedures. The MMS funds extensive monitoring programs, prepares detailed environmental statements, attaches special stipulations to leases to protect sensitive habitats, and is responsible for assuring that the impacts of its Offshore Minerals Management program to the marine environment are minimized. The MMS cannot ignore drilling fluid discharges. Therefore, MMS inspection personnel have the authority under the Act to prevent improper discharge practices in violation of EPA regulations. For example, certain operations in the GOM, although the lessee believed itself to be in compliance with EPA discharge criteria, have created an oil sheen. In such cases, MMS inspectors will require lessees to take corrective action necessary to meet any MMS requirements and will take actions in accordance with any agreements with EPA to assure that the discharges meet EPA requirements. Also, if a problem is not covered by the EPA permit, MMS has the regulatory authority to require corrective action until the permit has been revised. It should be noted that the provision does not authorize MMS to approve practices prohibited by EPA.

Comment—Several commenters objected to the prior approval requirement for the addition of petroleum substances to mud systems because many additives contain hydrocarbons in low concentrations and are approved for use by EPA. They also are concerned about the time that might be required to obtain approval in the event of an emergency.

Response—Studies have indicated that the presence of diesel fuel in drilling fluids greatly increases their toxicity. The MMS is concerned about unnecessary and excessive use of diesel fuel and the lessees' ability to identify and recover diesel contaminated mud and cuttings. Prior approval can be obtained with the APD. Lessees may identify, in their plan or APD, the petroleum substances which may be used, conditions under which they would be used, concentrations (range), and special recovery methods and procedures. The use of such components will have to be consistent with EPA requirements, applicable lease stipulations, and MMS regulations and conditions of approval. The MMS officials will inspect to assure that approved methods and procedures are being followed. Oral approvals are also on a viable alternative under § 250.6, when appropriate.

Comment—Several commenters objected to the requirement that maintenance or repairs be undertaken immediately when necessary to prevent pollution. They indicated that the most expeditious means of correcting a problem may not be a repair but some other type of procedure (e.g., a component shut in).

Response—The MMS believes that any type of action that corrects the underlying source of pollution should be considered maintenance or repairs and has not revised the language.

Comment—A number of commenters objected to the requirement that curbs, gutters, and drip pans be installed in all deck areas. They argue that certain areas on drilling rigs and production platforms may not be exposed to spilled oil and thus should be exempt from the draining collection requirement. They are also concerned that automatic maintenance of an oil level in a sump may not always be practical.

Response—The language of the rule has been revised to make it more performance oriented. Lessees will be required to install curbs, gutters, drip pans, and drains as necessary to collect all contaminants. Sump systems must be designed to prevent unauthorized discharges of oil or waste. The requirement that sump systems automatically maintain the oil at a level sufficient to prevent oil discharges has been retained. Automatic oil level controls on sumps are necessary to prevent unauthorized oil discharges, and such automatic level controls are feasible.

Comment—It was recommended that the drainage collection requirement for artificial islands be deleted because the requirement to place hydrocarbon vessels inside impervious berms was sufficient.

Response—This recommendation was not adopted. The requirement to place hydrocarbon vessels such that spills are contained does not assure that contaminated drainage will be properly collected. The drainage collection requirement is necessary to assure that contaminated drainage will be directed away from the rig to a suitable sump system.

Comment—One commenter requested more specificity regarding garbage disposal.

Response—Unauthorized discharges of garbage would be precluded by the requirements in § 250.40(a) and (b)(6).

Comment—One commenter objected to the equipment marking requirements as unnecessary. Another recommended that markings be durable enough to withstand environmental conditions. Several commenters requested that lessees be authorized to keep small tools in a suitable storage area, not just in a marked container.

Response—Equipment marking is specifically mandated by section 403(a) of the Act Amendments of 1978 (43 U.S.C. 1843). A performance standard concerning durability is included in § 250.40(c)(4). The rule has been changed to allow storage in a suitable area.

Comment—Numerous commenters felt that equipment or materials that are lost in greater than 1,000 feet of water, weighing less than 40 pounds, or within 150 feet of a fixed structure should not have to be reported or that any such reports should be made only to the USCG.

Response—No change has been made in this requirement. In some OCS areas, commercial trawling is frequently performed in water depths up to 3,000 feet. Also, materials lost in 1,000 feet of water may settle to the bottom at much lesser depths. Some work baskets, tires, and other objects weigh less than 40 pounds but can seriously interfere with commercial fishing.

The Act requires MMS to protect other users of the OCS. This cannot be accomplished without complete and accurate debris reporting. If the "loss" overboard of materials, equipment, tools, containers, and other items used in the OCS is held to a minimum, reporting their loss should not be burdensome.

Because MMS does not enforce reporting to other Agencies, the requirement that lessees report material losses to the USCG has been deleted. Lessees should refer to USCG regulations for their requirements on this matter.

Comment—Several commenters recommended that pollution inspections be required only at manned facilities during the course of normal operations rather than daily at all facilities.

Response—This recommendation was not adopted. The MMS believes pollution inspections should be a scheduled daily activity and documented at the facility. Observations during normal operations may not cover the entire facility and visible surrounding waters and would be difficult to document. Should daily inspections not be necessary at certain facilities with limited production equipment, the rule allows the District Supervisor to approve a lesser frequency.

Comment—One commenter recommended that the District Supervisor never allow more than 7 days to elapse between pollution inspections.

Response—This recommendation was not adopted. The rule allows the District Supervisor to set a frequency for pollution inspections other than daily for certain facilities. Instead of setting a maximum required interval, MMS believes that based on the circumstances, the District Supervisor is best qualified to set the interval.

Comment—The 2-year record retention period for pollution inspections and repairs was questioned.

Response—The retention time is necessary to allow for adequate analysis of pollution occurrences and is consistent with other similar recordkeeping requirements.

Comment—Several comments were received concerning oil spill reporting. Some commenters felt the requirement to report to MMS is redundant with USCG reporting requirements. Another commenter proposed that spills be reported to States as well as the District Supervisor.

Response—The MMS agrees that redundant reporting should be avoided if possible. However, MMS personnel must have immediate and accurate information on spills to fulfill their regulatory responsibilities. Also, there are often specific operational questions about an incident that cannot be answered by USCG personnel. It is, therefore, necessary for MMS to receive spill reports. Arrangements for reporting to State or other Federal Agencies can be provided for in OSCP's. Affected States can also arrange with MMS for reports of significant oil spills.

Comment—It was recommended that all oil spills, regardless of size, be reported immediately and confirmed in writing. Other commenters recommended that spills of 10 barrels or less be reported within 12 hours as proposed or, if on a weekend, on the first working day after the spill occurs.

Response—While immediate reporting is not necessary for every spill, the proposed threshold spill size of 10 barrels was too large. The rule has been revised to require immediate reporting for spills of more than 1 barrel. Spills of less than 10 barrels can create conditions for which some level of immediate spill response may be necessary. Spills of less than 10 barrels may also be indicative of operational practices that demand immediate attention. It is, therefore, imperative that the District Supervisor receive prompt notification of these spills. The rule for reporting small spills, now less than 1 barrel, requires a report within 12 hours. Although the cleanup options for spills of less than 1 barrel are limited, MMS may be alerted by other parties to the presence of a slick near a facility. Absent a spill report, the District Supervisor would be concerned about the possibility of an undetected (or unreported) large spill. An investigation would not be necessary if MMS had been advised of a minor spill at the facility.

Oil and gas drilling and production operations continue around the clock; therefore, a spill is as likely to occur on a weekend as a weekday. Based on the circumstances, the District Supervisor may choose to inspect the facility and verify that appropriate corrective action has been initiated. This would not be possible if the report was delayed until the following Monday morning. In addition, MMS has revised the requirement for written confirmation of spills to indicate that such written reports must be received within 15 days after the spillage has been stopped. The OCS Order No. 7 does not specify a timeframe for the transmittal of written reports. The 15-day requirement is necessary to assure that details on a spill are provided on a timely basis.

Comment—One commenter argued that "nuisance spills" of less than 50 barrels should not have to be confirmed in writing.

Response—Spills of 1 to 50 barrels are not considered to be "nuisance" spills. They can create extensive sheens and adversely impact marine life. It is expected that the infrequency of such spills should not make their reporting burdensome. Lessees should normally perform an internal review of such events, a copy of which should be sufficient written documentation for MMS's purposes.

Comment—One commenter suggested that lessees be required to notify the District Supervisor of observed pollution resulting from another lessee's operation.

Response—The recommendation was adopted and the provision added.

Comment—Commenters suggested that dispersant-use plans be specifically required as a part of the OSCP.

Response—The recommendation was adopted. The final rule requires dispersant-use plans.

Comment—One commenter questioned the need for any changes in OSCP requirements in light of the industry's excellent spill record.

Response—Although the number of large spills has been low, the success in responding to such spills has been limited. The changes in OSCP requirements are intended to improve overall response capabilities. Continued improvements in spill response capabilities are essential if the leasing and development objectives of the Act are to be accomplished.

Comment—It was recommended that the BAST requirement be cited in the OSCP requirements.

Response—This recommendation was not adopted. The BAST provision of the Act applies to all safety and pollution prevention requirements and need not, therefore, be specifically cited in the OSCP requirements. The Regional Supervisor will consider BAST capabilities in reviewing OSCP's.

Comment—A commenter suggested that lessees be required to install monitoring equipment to obtain oceanographic data for spill trajectory analyses.

Response—This recommendation was not adopted. The rule specifies the information required in a plan. Monitoring will be done when required to meet the requirements of the rule. When MMS requires oceanographic data beyond that required under the rule, MMS will contract for the data.

Comment—A commenter suggested that MMS and EPA avoid duplication and conflicts between OSCP's and the Spill Prevention Control and Countermeasures (SPCC) plan required by EPA.

Response—The MMS does not believe that SPCC plans are appropriate for the OCS and is reviewing this matter with EPA as part of the MOU implementation process and efforts to avoid duplication and conflicts with other Agencies' requirements.

Comment—Numerous commenters objected to the requirement for costly oil spill risk and trajectory analyses.

Response—The intent of this requirement is not to conduct new risk and trajectory analyses but to summarize applicable trajectory analyses published in EIS's or other public documents. Section 250.42(a) has been revised to require that applicable trajectory analyses be referenced and their results summarized.

Comment—Commenters were concerned that the trajectory analyses might not be sufficiently specific to be useful.

Response—The rule has been revised to require that the analyses discussed be specific to the area of operations and areas of potential onshore impact.

Comment—It was suggested that drogues, which could be used in tracking a spill at night, be kept at offshore facilities.

Response—This recommendation was not adopted. While night tracking is important and should be addressed in oil spill contingency planning, MMS has not included requirements for specific response methods or types of equipment in these rules. Lessees will include specific equipment and procedures for spill tracking and cleanup in their contingency plans, and the adequacy of such plans will be reviewed by MMS, USCG, and the affected State(s).

Comment—Another commenter suggested that trajectory analyses include estimates of the time it would take for a spill to reach environmentally sensitive areas.

Response—Such information may be included in MMS lease-sale trajectory analyses and other such analyses contracted for by lessees. If additional trajectory information needs are determined during the leasing or plan review process, the Regional Supervisor can require supplemental trajectory data.

Comment—Numerous commenters requested deletion of the requirement that equipment capable of recovering at least 1,000 barrels of oil per day be located so as to assure a 12-hour response time. They indicated that environmental conditions do not always permit such recovery rates and that it may not be practical to locate such equipment within 12-hour transit time of all facilities. They further stated that spills 100 miles from shore do not require such rapid response. Another commenter stated that a 12-hour response time is inadequate in some coastal areas.

Response—This recommendation has been adopted. The specific response time and recovery capability requirements have been deleted. Because of the wide range of environmental settings in which facilities are located and the large differences among such facilities, permissible response times and capabilities vary between and within Regions. The Regional Supervisor, in consultation with the USCG and other reviewers, will determine response capability requirements.

Comment—One commenter indicated that lessees should be able to reference oil spill cooperative plans in identifying response equipment.

Response—Such referencing is authorized under the rules as written. In addition, a provision has been added to require inspection of equipment at least monthly.

Comment—One commenter questioned the necessity of the requirement for listing uncommitted spill response equipment available for use.

Response—Upon reconsideration, it was recognized that the proposed requirement could be confusing. The language regarding the listing of uncommitted equipment is not contained in the final rule.

Comment—A commenter suggested that names, not just positions, be used in designating response personnel because individuals can be questioned regarding their training experience but positions cannot.

Response—This recommendation was not adopted. It is not practical or

feasible to require designations by name. On a rig or platform, numerous individuals may fill a specified position during the course of a year. As long as the position title is specific enough, MMS inspectors can ascertain whether the person that is functioning in that capacity has had the required level of training.

Comment—Commenters indicated that personnel supervising oil spill response operations need not receive extensive training in the deployment of equipment but need to be trained in directing the deployment and use of equipment. Only those supervising the actual cleanup operations should be required to receive the supervisory level response training.

Response—The rule has been revised to acknowledge that the knowledge and skills required for response supervisors differ from those needed by the response team. All personnel identified in the OSCP as cleanup response supervisors are required to receive the supervisory level training regardless of what phase they are supervising.

Comment—Several commenters requested deletion of the requirement that training records be retained at the lessee's field office nearest the facility. They noted that many of the people receiving such training are contract personnel and that the lessee's nearest field office may not be the appropriate location for such records.

Response—The rule has been changed to require that such records be maintained for 2 years at a site designated in the lessee's OSCP.

Comment—Numerous commenters recommended that oil spill drill frequency be reduced from semiannually to annually as this frequency has proven adequate under existing rules.

Response—This recommendation was adopted. One scheduled drill each year is sufficient. Response personnel will also be participating in annual hands-on training exercises, and the Regional Supervisor may require additional scheduled drills or initiate unscheduled drills. The Regional Supervisor can evaluate the scheduled and unscheduled drills to determine optimal frequencies for drills at different areas or facilities.

Comment—Several commenters opposed the provision for unscheduled drills initiated by the Regional Supervisor. Other commenters felt that surprise drills should be required.

Response—The MMS believes that unscheduled drills are an effective means of evaluating personnel and equipment readiness. The MMS personnel will evaluate conditions and the status of operations in advance to assure that such drills do not impair operations or impose unusual risks to lessee personnel.

Comment—Objections were raised to the necessity of requiring MMS approval of the equipment to be deployed and the drill schedule.

Response—This recommendation was adopted. The Regional Supervisor will receive notification of the drills and equipment to be deployed. If changes are desired, the Regional Supervisor can request them or require additional drills. The Regional Supervisor can also require changes in the OSCP which describes training procedures. Through this process, the supervisor can modify drill-training procedures.

Comment—Comments were received requesting more detailed requirements on the conduct of response drills.

Response—This recommendation was not adopted. Because of the inter and intraregional differences in environmental conditions and types of operations, the Regional Supervisor must be permitted sufficient latitude to assure that prescribed drill procedures are appropriate for the specific circumstances at the site. The MMS, therefore, chose not to list criteria that the Regional Supervisor must utilize in evaluating drill performance. A provision has been included for the Regional Supervisor to evaluate drill results. Objective evaluation criteria will be developed on a regional basis. All surprise drills and many scheduled drills will be monitored and evaluated by MMS personnel. To assist States in their review process, the Regional Supervisor may offer State representatives the opportunity to witness response drills. In addition, local government representatives and members of interest groups or the public may be permitted to witness drills. They should contact the Regional Supervisor to ascertain whether such arrangements can be made.

Comment—Numerous comments were offered regarding the air quality regulations.

Response—No action is being taken on the air quality regulations pending completion of the negotiated rulemaking process. These comments have been forwarded for their consideration to MMS personnel involved with these proceedings.

Subpart D—Drilling Operations

During the review of the proposed rule and public comments thereon, a number of points were noted that could be addressed by minor revision of the text of the proposed rule. Generally, these changes are not substantive in nature, are viewed as editorial, and are presented without detailed discussion. A discussion of the public comments on proposed Subpart D and responses to those comments are provided following the discussion of the editorial changes.

Proposed § 250.123(d) in Subpart H, Production Safety Systems, required submittal of a general and a supplemental plan for simultaneous operations which applied to drilling and other operations on production facilities. The proposed requirement for such plans has been eliminated and replaced with specific requirements which appear in Subparts D, E, and F. Two new paragraphs, § 250.51(h), Equipment movement, and § 250.51(i), Emergency shutdown system, have been added to Subpart D to provide the specific requirements.

A new paragraph (4) is added to § 250.52(a) which provides for relocation of equipment which contains hydrocarbons or other flammable substances 35 feet from the welding site. It also requires relocation of such items 35 feet horizontally from decks underlying the work area. If relocation is impractical, the equipment is to be shielded or the contents rendered inert. Similarly, the clause "and areas at elevations below the work area where slag, sparks, or other hot materials could fall" is added following "shall inspect the work areas" in § 250.52(d)(1).

A provision is added to § 250.54(a)(2) specifying that cement placed across permafrost zones is to be of a type that will set before freezing and has a low heat of hydration. This makes the paragraph consistent with § 250.112(k) in Subpart G, Abandonment of Wells.

The reference to a minimum setting depth of 100 feet for drive or structural casing is deleted from § 250.54(b) to make the regulation consistent in its reference to setting depths of various casing strings. No such minimums are given at § 250.54 (c), (d), or (e). The language at § 250.54(c)(1) was changed from reference to a "correlatable well" to an "offset well" to clarify the intent of the paragraph. The language at § 250.54(c)(2) was changed from "ocean floor" to "mud line" to make the regulations internally consistent.

The language of § 250.56(d)(7)(ii) was revised to make clear that choke manifold systems are to be heated, drained, or filled with antifreeze only if there is a chance of freezing.

Language was added to § 250.57(e)(2) to clarify that in cases where cement is not to be drilled out, blowout preventer (BOP) systems shall be pressure tested before continuing operations.

The language at § 250.57(e)(5) addressing testing of variable-bore pipe

rams was changed to recognize that there could be more than two sizes of drill pipe in a string but to clarify that testing of the rams against drill collars or tools in the string is not required.

A new § 250.60(b)(8) was added to require an operable gas separator. The requirement had previously been omitted under the assumption that all rigs carry this equipment as standard. However, it is sufficiently critical as to be explicitly required.

The title of § 250.61 was changed from "Well security" to "Securing of wells" to avoid any confusion with requirements relative to theft of oil or equipment as used in § 250.184 of Subpart L.

The phrase "type of connection" was added to § 250.64(f)(4)(i). This casing factor was inadvertently omitted from the proposed rule and is a factor which bears directly on the strength of the casing joints.

The language at § 250.65(b) requiring a subsequent report of work to be filed was changed from "After completion of the work" to "Within 30 days after completion of the work" to make clear that the report must be submitted within a reasonable period of time.

The language of § 250.66(c)(2) was revised to clearly require that upon request, a lessee is to furnish paleontological reports and/or washed samples of cuttings. The language of § 250.66(f) is revised to indicate that the lessee may, in some circumstances, be required to submit other reports and paleontological interpretations based upon identification of microscopic fossils.

The first sentence in § 250.67(h)(6)(vi) regarding emergency breathing air systems was revised to clarify that the requirements are to conform to any particular operation, i.e., drilling, well-completion, well-workover, or any combination thereof.

Similarly, § 250.67(m)(8) was expanded to clarify that the corrosion mentioned refers to corrosion caused by acid gases such as H_2S and carbon dioxide.

Section § 250.68, Training in well control, has been removed from Subpart D, Drilling Operations, and combined with sections from other subparts dealing with training into a separate Subpart O, Training in OCS Operations.

Comment—There were many comments concerning § 250.50, Control of wells. One commenter stated that this section appears to be in order. One commenter recommended use of the term "BAST" only and deletion of the words "state-of-the-art," and references the National Academy of Science (NAS) study "Safety and Offshore Oil" (1981) and requests a specific MMS response to this recommendation. Other commenters would delete references to BAST and state-of-the-art methods and allow lessees some latitude in selecting the appropriate technology best suited to a particular well on the basis that all wells do not require the same degree of technology.

Several commenters believe that the regulations themselves should be more specific with less reliance upon the discretion of the District Supervisor.

Several commenters would delete the word "assure" regarding safety and protection of personnel and equipment and would delete the word "competent" regarding personnel.

One commenter recommended the use of objective, verifiable performance standards since the proposed section has no objective standards that would not already be subject to § 250.3, Performance requirements; does not call for notice to the affected State if alternative procedures or departures were approved by the MMS District Supervisor; and states that §§ 250.52(b), 250.54(a)(3), and 250.62 are not sufficiently precise to provide objective standards.

Response—These recommendations have not been adopted. The commenters who expressed concern regarding the balance between performance standards and specific requirements in this section are referred to the discussions presented in §§ 250.3, 250.20, and 250.22 in Subpart A of this part.

Section 250.50, Control of wells, was intentionally worded generally. The purpose of this section is to provide stated goals, direction, and meaning to the more specific requirements which are presented in subsequent sections of Subpart D.

Many of the decisions within the context of the regulations involve situations which require evaluation of varying engineering and other parameters unique to the situation and require a decision by an informed and responsible MMS official.

Proposed casing programs and welding and burning plans submitted for approval are carefully reviewed for safety and environmental protection within the overall picture prior to approval. Section 250.64, Applications for Permit to Drill, requires lessees to submit substantial additional information which MMS personnel use in making approval decisions. Welding and burning plans must also satisfy the specific requirements in § 250.52. The requirements in § 250.52 of the final rule have been revised to add specifics and increase stringency.

Section 250.62 enables the District Supervisor to determine specific operating requirements different from these in the regulations when sufficient drilling geologic and engineering information is available to clearly demonstrate that rigid compliance with a specific requirement as written is no longer necessary to maintain the required levels of safety in operations and environmental protection. Section 250.62 also allows the District Supervisor to invoke additional and/or more stringent requirements when drilling and other experience in the area reveals the existence of special problems not specifically addressed in the basic requirements.

Although the only revision to the text of proposed § 250.50 was deletion of the words "and state-of-the-art methods * * * appropriate methods" revisions to § 250.52 were made in response to comments received on both sections.

The BAST requirement in Part 250 is mandated by section 21(b) of the Act, as amended, on September 18, 1978.

Section 21(b) recognizes that in a given situation more than one technology may provide an acceptable level of protection and provides an exception where the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

In response to comments regarding the NAS Study of 1981, MMS has had standing committees and organization units which address offshore technological assessment for more than 8 years. The function of these groups is to identify, evaluate, and report on the use of BAST on a continuous basis. Literature on BAST is researched; continuous observations of field practices are made; meetings are held with industry representatives and vendors of oil field equipment and services for this purpose; and meetings are conducted routinely with MMS personnel and others to disseminate and utilize BAST information.

Technology which permits the measurement of wellbore characteristics while actively drilling, termed "measurement while drilling" (MWD), has developed to field-proven status and continues to be improved. The voluntary use of MWD technology by lessees is increasing on the strength of its utility and cost effectiveness in the drilling process. This technology may be required at some future date when circumstances warrant its use in specific drilling situations.

Comment—A commenter recommended that MMS adopt standards (Section VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel

Code, and ANSI/ASME B31.3—Chemical Plant and Refining Piping) in § 250.51 to provide design standards for pressure vessels and piping for drilling systems on fixed OCS facilities, as the USCG requires conformance with these standards on MODU's and floating facilities in 46 CFR Part 54.

Response—This suggested change was not adopted because it does not appear justified for drilling systems.

Comment—There were several comments concerning the proposed requirement at § 250.51(a)(2) for a drilling unit to be "made ready" and available for a complete inspection by MMS personnel before commencing operations. Some commenters suggested deleting the words "made ready" as unnecessary and undefined. One commenter requested clarification as to whether the inspection would occur prior to moving onto location or prior to spud.

Response—Drilling unit inspection by MMS personnel, for the purpose of evaluating the fitness of the drilling unit for approval to operate in an area, can be conducted before the unit moves on location or concurrently with the predrill inspection prior to spud. Any deficiencies found at the time of these inspections are noted, and a copy is given to the operator. Approval for use of the drilling unit is contingent upon the lessee correcting all noted deficiencies prior to spudding a well. Modifications that are required as a result of deficiencies noted during a predrill inspection could be costly as well as time consuming to accomplish and could delay the spudding of a well if conducted concurrently with a predrill inspection immediately prior to the planned spudding date. When requested by the lessee, MMS personnel have conducted such inspections well in advance of the movement of equipment into an area.

To avoid any undue delay in spudding the first well to be drilled with a drilling unit, the lessee should notify the District Supervisor and arrange for an inspection of the unit as soon as the expected date of drilling unit arrival on location becomes known with reasonable certainty.

Comment—There were a number of comments concerning the lessee submittal of information and data with the APD on the fitness of the drilling unit to perform the proposed drilling operation at § 250.51(a)(3). All the commenters suggested deleting this proposed requirement, since they believe the lessee is best equipped to evaluate the drilling unit and its capabilities and believe that the proposed requirement would cause an unnecessary paperwork burden.

Response—The recommendations to delete the requirement were not adopted. The MMS, along with other Federal Agencies, has responsibilities for evaluating the safety and environmental protection aspects of drilling operations in the OCS. Fitness of drilling units is an important part of this evaluation. The provision for the District Supervisor to require a third-party review of a drilling unit when the submitted information is insufficient to demonstrate the suitability of or the site-specific use has been made applicable to cases when the drilling unit has not been proven in the proposed environment. As originally proposed, the requirement applied only to arctic operations.

Comment—There were many comments submitted concerning the proposed requirement at § 250.51(b)(2) to equip all diesel-engine air intakes with an automatic shutdown device to prevent diesel engine runaway. A few commenters recommended deletion of the proposed requirement since it is believed that it would require modification of numerous engines without adequate justification. Some commenters suggested more detailed studies are needed to assure that the right problem is being addressed and that the proposed remedial action will not inadvertently create additional safety hazards. Several commenters recommended rewording the proposed requirement to include only unattended diesel engines within 1 year from the effective date of the regulations and to exclude engines involved in emergency functions. One commenter suggested amending the proposed requirement to waive such a requirement where overspeed shutdown mechanisms are installed or where gases necessary to cause engine overspeed and fires would not normally be present. One commenter suggested that it is doubtful that a case can be made for the proposed requirement and that hardware requirements for drilling units should be located in the USCG's Title 46 of the Code of Federal Regulations to avoid conflicting requirements.

Response—The recommendations have not been adopted. However, the regulation has been revised to exempt those diesel engines which are continuously attended from automatic shutdown device requirements but will include other diesel engines in all areas including those intended for emergency use. It was recognized that a rule which would require automatic shutdown devices is not appropriate for diesel engines which are continuously attended. Often, diesel engines which power emergency activities will be continuously attended, in which case they would be exempted from automatic shutdown devices. Diesel engines located in an area where combustible gas is not likely to be present have not been exempted from the requirement for automatic shutdown devices unless they are continuously attended.

Comment—There were several comments submitted concerning the proposed requirement at § 250.51(d)(1) for a survey strategy to be submitted to the District Supervisor. All of the commenters recommended deletion of the proposed requirement regarding survey strategy since it is believed to be too vague and not an MMS responsibility. Minimum requirements should be given for the required survey so the lessee can meet the requirements.

Response—This suggestion has been adopted, and proposed § 250.51(d)(1) was deleted. The title has been changed to "Foundation requirements" and reference made to the requirements for shallow hazards surveys pursuant to §§ 250.33 and 250.34. The NTL's on shallow hazards surveys now outstanding are retained and remain in effect.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.51(d)(2) for the District Supervisor to optionally require soil boring tests prior to moving jack-up rigs on location. Several of the commenters recommended that the proposed requirement be amended to require that the lessee "have sufficient knowledge of the ability of the seafloor to support the rig prior to commencing drilling operations" and that soil borings may be excessive if area data are available. One commenter suggested that a diver survey could satisfy the proposed requirement.

Response—These recommendations have not been adopted. However, the text of the final rule has been revised to clarify the intent and facilitate compliance. It is understood that some soil borings are taken with the jack-up rig in place before preloading, and in certain areas, soil boring data may exist from offset wells or platform locations. In practice, existing data concerning soil competency are taken into account on a case-by-case basis before the authority specified in this rule is invoked.

Comment—There were several comments submitted concerning the requirement for the lessee to obtain the information proposed in § 250.51(e)(1). All the commenters recommended that the proposed requirement be deleted, since it is believed that it is in the

lessee's best interest to evaluate totally the formations encountered and that the District Supervisor should not be allowed to require additional logs, tests, and surveys. Also, it was suggested that the reference to casing, tubing, and other pressures is misplaced.

Response—The recommendation has not been adopted. Evaluation of the formations encountered is in the lessee's and the Government's best interest in order for each of the parties to assess resource potential and to inventory reserves of hydrocarbons. Agreement between the District Supervisor and the lessee at the time of APD approval assures that those interests are well served. The specific tests and surveys necessary for the evaluation of formations penetrated by a well are different for each well depending on the specific circumstances unique to that well. The District Supervisor considers many factors including well site, wellbore conditions, and drilling equipment capabilities before requiring additional tests, samples, or surveys which are not proposed by the lessee in an APD. The reference to "casing, tubing, and other pressures" was deleted as inappropriate.

Comment—There were several comments submitted concerning the proposed requirement at § 250.51(e)(3) that a composite dipmeter directional survey is acceptable on vertical wells. The commenters recommended that an MWD composite survey also be acceptable. One commenter suggested that language should be added to clarify that MWD directional surveys without further checkshots (at the benchmark) are acceptable while drilling, rather than no more than every 200 feet (due to present day long-life bits) and that confirmation (at the benchmark) can be obtained using multishot surveys at each casing point.

Response—These recommendations have been adopted, and § 250.51(e)(3) of the final rule has been revised accordingly. The MWD technology has proved to be an accurate and reliable method of tracking the migration of a borehole in those cases where a confirming multishot survey is run at each casing point.

Comment—Several comments were submitted concerning the proposed requirement at § 250.51(e)(4) to classify wells as vertical if inclination does not exceed an average of 3 degrees. All the commenters recommended clarification as to how the average of 3 degrees is determined.

Response—The text of the provision has been revised to clarify the intent of the rule. It is intended that the average of 3 degrees be calculated by averaging the inclination readings weighted by the interval length between readings. Minimum interval lengths between readings are given in § 250.51(e) (2) and (3) of the final rule. Wells being drilled are classified as directional when the calculated weighted average inclination from the surface to measured drilled depth exceeds 3 degrees. It is possible that during the course of drilling operations, a borehole's classification may vary between vertical and directional.

Comment—There were several comments submitted concerning the proposed requirement at § 250.51(e)(5) for the Regional Supervisor to provide a lessee of an adjoining lease a copy of the directional survey, if requested. All the commenters believe that the proposed requirement should be deleted and that MMS, not the adjoining leaseholder, should determine that wells are drilled within legal confines.

Response—The recommendation to delete was not adopted. The responsibility of the lessee to confine its drilling to the legal boundaries of a lease is clear. However, when the technical method and procedures by which a survey was obtained are susceptible to credible alternate interpretations by lessees and MMS, and a dispute develops between leaseholders over the question of a wellbore's path, the adjoining lessee has a right to know the basis for an MMS determination that a wellbore did or did not cross the lease boundary.

Comment—There were many comments submitted concerning the proposed requirements at § 250.51(g) relating to crane operations on fixed platforms. Several of the commenters recommended deletion of the proposed requirement since it is believed to be a USCG responsibility. The USCG recommended the proposed requirement be retained until the USCG "Offshore Cranes" regulatory project (CGD 79-059) is completed.

Response—The recommendation to delete was not adopted. Deletion of this requirement at this time would create a regulatory gap and confusion over the need for compliance. The MMS regulations will be left in place until the USCG regulations become effective. That action by the USCG will permit MMS to delete the requirement from its rules.

Comment—There were several comments submitted concerning the proposed requirements at § 250.52(a)(2) on welding and burning offshore. One commenter recommended that MMS and USCG jointly develop one set of regulations for MODU's. The remainder of the comments recommended deleting the proposed requirement regarding onshore fabrication since it is believed that economics will ensure that offshore fabrication is minimized, and it is also believed that the requirement could cause problems in interpretation.

Response—The recommendation to delete was not adopted. If economics alone ensure that offshore fabrication is minimized, then this regulation does not impose an undue burden. Onshore fabrication is required only "when feasible." This requirement has been part of the regulations for many years, and there have been no known problems regarding its interpretation.

Comment—There were several comments submitted concerning the proposed requirement at § 250.52 (b), (c), and (d) to submit a welding, burning, and hot-tapping plan designating safe-welding and burning areas. One commenter recommended that the plan be approved by the Regional Supervisor rather than by each District Supervisor.

Several commenters would revise the requirement so that the welder rather than the welding supervisor be thoroughly familiar with the plan and also suggest that the proposed requirement is inappropriate for welding equipment on drilling rigs except during simultaneous operations. A few commenters suggested deleting the second sentence of the proposed paragraph regarding welders qualifications since it is believed that welding operations on drilling facilities require no special certification.

One commenter would delete the proposed requirement for welding and burning equipment to be inspected by the welding supervisor or the lessee's person-in-charge since it is believed a performance standard could address this concern. One commenter recommended that a copy of the plans be kept in the field rather than on the facility to provide access to the plan for all subject operations.

Response—These recommendations were not adopted. The MMS Regional Supervisors are "one-step removed" from the scene of operations. Welding, burning, and hot-tapping operations are more appropriately regulated close to the scene of activities where the best information is available. If the lessee believes a plan prepared for approval is applicable to all Districts within a Region after considering site-specific conditions which may vary from District to District, copies of the same plan may be submitted for approval to all Districts within the Region.

The intent of the words "welding supervisor or lessee's designated person-in-charge" was to assure lessee's

management control (accountability) over welding operations, to assure that the duties and responsibilities of lessee and contractor employees are clearly defined, and that lines of authority and accountability be established and maintained. Accidents in welding and burning operations are chronic, of relatively high frequency, and are believed to be reducible. Accident investigation reports often show that the lack of a clear-cut definition of responsibilities, coordination, and supervisory control are factors of the cause of the accident.

The requirements for engine-driven welding machines are applicable to welding operations on all offshore facilities. On facilities where only drilling operations are taking place, there remains a potential for explosions and fires due to the presence of flammable materials such as trip gas, chemicals, solvents, diesel fuel, produced well test fluids, and oxygen and fuel gas used for welding operations. Accidents have occurred while torch-cutting on casing as gas was evolving from the mud in the casing. The chances of a fire or an explosion are increased while conducting simultaneous drilling and production operations.

For safety reasons, it is believed that welding and burning equipment must be inspected prior to conducting operations by a knowledgeable person who also has supervisory responsibility. There is no intent to specify any particular party, only that the lessees recognize their accountability by formally designating a person in a supervisory capacity as being responsible.

A readily accessible plan is more likely to be followed. To be readily accessible, a plan needs to be at the worksite. The lessee has a responsibility to establish and maintain its plan(s) and to assure that current copies are readily available at drilling and production facilities, and that the personnel on these facilities are familiar with the content of the plan(s).

Comment—There were several comments submitted concerning the proposed requirement at § 250.52(d)(1) to certify the welder's qualifications for operations in undesignated welding areas. A few commenters suggested deleting the proposed requirement in the belief that welders on typical drilling operations are not certified for pressure vessel or piping welding, and that the requirement is not necessary. Also, there is no "welding supervisor" on a drilling unit. One commenter suggested adding that a one-time establishment of a safe-welding and burning area on an MODU should suffice and not require a submittal to each MMS district.

Response—These recommendations were not adopted. This provision does not require a formal welding certification for high-pressure piping or vessels. It requires that the lessee's standards for qualifying rig welders be included in the Welding, Burning, and Hot-Tapping Safe Practices and Procedures Plan. The primary concern about rig welders who perform day-to-day operations is that all necessary safety measures be taken with respect to each welding action.

Once approved by a District Supervisor, a designated safe-welding and burning area for an MODU is applicable within the jurisdiction of that District Supervisor; and it need not be resubmitted for approval unless modifications are made to the MODU which mandate reconsideration of the approval or the MODU moves to another District. In recognition of the fact that some drilling units and structures have no space which could be designated as safe, the first sentence of § 250.52(c) in the final rule was revised by changing the phrase "The lessee shall" to "The lessee may."

Comment—There were many comments submitted concerning the proposed requirement at § 250.52(d)(2) for a fire watch. Several commenters would add language to clarify that the fire watch shall not have other duties during actual welding and burning operations. One commenter would add that the fire watch be on duty for 30 minutes after welding and cutting to be able to determine a potential fire near confined spaces and would require two or more fire watches to cover all exposures, both outside and inside confined spaces.

Response—These recommendations have been adopted. The text of the proposed rule has been revised to clarify the requirement by inserting the words "welding or burning" before the word "operation" in the first sentence and substituting them for the word "such" in the third sentence. The rule was also revised by adding the words "actual welding or burning" after the word "while" in the second sentence.

The text of § 250.52(d)(2) of the final rule was also revised by adding a requirement for the fire watch to remain on duty for a period of 30 minutes after welding or burning operations have been completed. Fires and explosions have occurred because the heat generated by the process ignited combustible substances which flared-up after the person performing the welding or burning left the area.

A recommendation that *every* operation have at least two fire watches is considered excessive. The requirement regarding the number of fire watches on duty is intentionally flexible. The welding supervisor or person-in-charge is responsible for determining the appropriate number of persons to name as fire watches.

Comment—There were several comments submitted regarding the proposed requirements at § 250.52(d) (5) and (6) concerning welding operations during drilling, well-completion, well-workover, wireline operations, and in well-bay or production areas.

Several commenters recommended deletion of paragraphs (5) and (6) on grounds that the regulations provide the performance criteria applicable to welding in undesignated areas and, therefore, the paragraphs are unnecessary. One commenter recommended revision of the proposed requirement in § 250.52(d)(6) to prohibit welding and burning *within* 10 feet of the well-bay or production area.

Response—The recommendations to delete these requirements have not been adopted; however, the recommendation to expand the safety area to 10 feet around a well-bay or production area has been adopted. Well-bays and production areas contain sources of highly flammable substances, usually under pressure. Welding or burning creates a high-temperature source of potential ignition. Previous interpretations made by MMS restricted welding and burning operations within 10 feet of the well-bay.

Comment—One commenter stated that § 250.53 contains requirements applicable to both drilling and production operations and is, therefore, out of place in this subpart and should appear in Subpart A—General.

Response—This recommendation has not been adopted. Subpart A contents, in general, are not as field-related and specific as those in this subpart. This and similar other requirements are applicable to drilling, well-completion, well-workover, wireline, and production operations. There is no clear "best" location for the provision and reiteration of the requirement in each subpart is not desirable.

The location of requirements for electrical equipment is unchanged; however, this section is directly referenced in Subpart E, Well-Completion Operations at § 250.78 and in Subpart F, Well-Workover Operations, at § 250.98.

Comment—There were several comments submitted concerning the provision at § 250.53(a) requiring low-

tension ignition systems on all engines with electrical ignition systems. All the commenters objected to the proposed rule which specifically requires a shielded ignition system. One commenter would replace "combustible mixture" with "ignitable concentration of gas or vapor" to agree with the language of API 500B.

Response—These recommendations have been adopted in part. The text of the regulation has been revised to require that all engines with electrical ignition systems be equipped with a low-tension ignition system or a shielded-ignition system.

This revision allows lessees an option to continue to use existing shielded-ignition systems. The text of the paragraph was changed to "combustible mixture or substance" since gas or vapor might not be interpreted to include volatiles from a liquid.

Comment—There was one comment concerning the proposed requirement at § 250.53(c) that all electrical installations be made in accordance with API RP 14F, except sections 7.4 and 9.3. The commenter would amend the proposed requirement to clarify that existing installations are not subject to the proposed requirement.

Response—This recommendation has not been adopted. The National Electrical Code (NEC) and API RP 500B have been incorporated by reference in the rules for more than 15 years. The contents of these documents are the basis for API RP 14F. The API RP 14F focuses on offshore operations in contrast to the NEC. No compliance problems during the transition period are expected, and on this basis, stating a lead time for compliance is considered unnecessary. Recourse to § 250.3 is available in the event a transition problem should develop.

Comment—There were many comments submitted concerning the required integrity testing of the cement fill at § 250.54(a)(2). Several commenters suggested that the required formation-integrity test is sufficient and that the required 500 feet of annular cement fill and 500 psi compressive strength are arbitrary. One recommended that the reference to waiting time be deleted from the last sentence because additives can be used to reduce the time needed to reach the required compressive strength. Finally, one commenter urged that the words "after 12 hours waiting on cement" be added to the end of the paragraph.

Most of the commenters on §§ 250.54(a)(2), 250.55(d), and 250.64(f)(6) recommended the deletion of the requirements for 500 psi cement compressive strength, 500 feet of cement fill above the casing shoe, 8- and 12-hour waiting times, and submittal of a cementing program on the grounds that these specific requirements are arbitrary and have no basis in current technology. They further asserted that the cementing program should have no bearing on the permit to drill and that the formation-integrity test alone is sufficient for evaluation.

Response—These recommendations have not been adopted. All of the proposed requirements are and have been required for many years in one combination or another in Federal and State oil and gas regulatory programs. The standards specified in § 250.54 of the final rule are considered reasonable and prudent without being excessive.

The quality and quantity of cement placed behind casing during well drilling operations are of vital importance from the time of setting conductor casing through all drilling, completion, and workover operations, over the producing life of the well, and through and after well abandonment. Zones must be isolated, casing laps sealed, and fluid migration behind casing prevented.

Comment—There were many comments submitted concerning casing program design and the associated safety factors at § 250.54(a)(3). Several commenters recommended that the term "sufficient magnitude" in reference to safety factors be deleted. They claimed that the term is extremely vague and ambiguous and that the listing of anticipated loads adds no meaning to the requirement. One commenter agreed with MMS in that a performance standard is indicated. Finally, one commenter suggested that some design criteria must be agreed on especially in the area of maximum anticipated surface pressure.

Response—These recommendations have not been adopted. The list of loads and stresses are given for purposes of communicating to the lessee the factors to be considered while preparing a casing design for submittal for the District Supervisor's approval. The factors listed are some that the District Supervisor takes into account during the review and approval/disapproval process. The main purpose of the list is to minimize the number of design rejects and resubmittals.

Lessees are free to select between the various acceptable design methodologies, criteria, and specifications. The MMS considers it unwarranted and unwise to lay down prescriptive rules in this area. The lack of specificity in parts of § 250.54 is deliberate. The purpose is to give direction toward reaching minimum goals, not specific design methodologies, criteria, and specifications.

Comment—There were a number of comments submitted concerning the pressure-integrity and pore-pressure tests provisions at § 250.54(a)(6). Several commenters recommended that the pore-pressure test and hole behavior observations related to pore pressure not be included on the driller's report. They believe that this requirement is unnecessary documentation and not the responsibility of the drill crew. One commenter noted that the situation of equivalent mud weight exceeding the pressure-integrity test could occur if the formation is only tested to a predetermined pressure value rather than testing to true leak-off.

Response—These recommendations have been adopted in part. Hole conditions will ultimately determine the optimum casing setting depth. This is a primary reason for the District Supervisor's need to have the required information. It is the lessee's responsibility to obtain the required information and to record and transmit that information to the District Supervisor whether on the driller's report, enclosed with the driller's report, or by separate dispatch.

New language has been added to the paragraph to explicitly provide for maintenance of a safe margin between the equivalent mud weight as determined in the pressure-integrity test and the mud weight in use. Drilling operations are to be suspended when the safe margin is not maintained.

Comment—There were many comments submitted concerning conductor and surface casing setting depths at § 250.54(c)(1). Several commenters recommended that the requirement to submit a revised casing program when unexpected formation pressures are encountered be eliminated on the grounds that it represented an unnecessary paperwork burden. Their position is that when unexpected formation pressure is encountered, the casing is normally set at a shallower depth and does not require a complete casing program revision. Another commenter would ask for verbal approval in these situations but would want the leeway to use sound engineering practice. Another commenter believed that if requirements for specific setting depths for surface casing are deleted, a cement bond log should be required to provide increased assurance of an adequate cement job. One commenter suggested that MMS establish objective and verifiable standards for the setting depths of conductor and surface casings. Finally, a

commenter requested that the regulations provide a means to obtain approval for the elimination of conductor casing.

Response—These recommendations have not been adopted. Encountering unexpected formation pressure during drilling may necessitate the initiation of actions that range from a minor to a major revision in the casing program. Casing programs and major changes in those programs must be approved by the District Supervisor. Provision is made in § 250.3 for oral request and approval provided the action is subsequently confirmed in writing.

A cause-and-effect relationship between removal of specified setting depth ranges and a consequent requirement that a cement bond log be run in every case as the commenter suggests is of questionable validity.

The rationale for removing specified casing setting depths as given in the preamble to the proposed rule was that the specificity of the rule did not contribute to increased safety, yet it generated unnecessary paperwork in the form of requests for departures.

Section 250.54(a)(5) permits the lessees to select between several of the available methods of evaluating a cement job other than a cement bond log. A regulatory requirement that a cement bond log be run in every case is not justified.

To satisfy the provisions and allowances in this paragraph, the lessee may request permission to eliminate the conductor casing in the APD and enclose the necessary engineering and geological information to justify the request.

Comment—There were several comments submitted concerning the conductor casing requirements at § 250.54(c)(2). All commenters recommended the deletion of the requirement regarding verification of cement fill by observing cement returns. Their position is based on the following rationales:

1. Circulation of cement in conductor holes is sometimes impossible, and large cement quantities can be required with no apparent benefits.

2. Final cement displacement could not begin until cement returns are established; hence, large quantities of cement might be circulated to the surface.

3. Additional cement and storage which may or may not be used add unnecessarily to the cost of the well.

4. Top-fill jobs are sometimes impractical.

Response—This recommendation was not adopted. A good cement job on the conductor is an important safety and well-control matter, particularly when high-pressure shallow gas may be encountered. It is recognized that top-fill jobs are sometimes impractical. The rule is written for and applies to the vast majority of cases. Exceptions are provided for by the general departure mechanism in § 250.3 of this part.

Comment—A few commenters recommended that the last sentence of § 250.54(c)(3) be deleted because attempting to pump additional cement may establish communication with a fault or fracture and cause well-control problems.

Response—This recommendation was not adopted. The MMS recognizes the commenter's point but believes that the necessary flexibility is provided in the proposed rule by the phrase "or as approved by the District Supervisor."

Comment—There were several comments submitted concerning the setting of intermediate casing at § 250.54(d)(1). All commenters suggested that the reference to the capabilities of the drilling unit is unnecessary and should be deleted.

Response—This recommendation was adopted. Reference to the drilling unit capability within the context of § 250.54(d)(1) is unnecessary and may cause confusion. Drilling unit capability is addressed in § 250.51. Therefore, the reference to drilling unit capability was deleted from § 250.54(d)(1) of the final rule.

Comment—There were several comments submitted concerning the use of a liner as an intermediate string as provided at § 250.54(d)(3). A number of the commenters suggested the requirement be changed to read "If a liner is used as an intermediate string below a surface casing string, it shall be lapped." Their position is based on the reasoning that some intermediate liners are set inside another intermediate string and can be safely designed such that an intermediate liner can be utilized for production without a tie-back to the surface. The remaining commenter stated that there is nothing inherently wrong with utilizing a combination of a liner and surface casing if the casing design is sufficient for production purposes.

Response—These recommendations have been adopted in part. The commenters' proposed revision captures the intent of the proposed rule and enlarges its scope to allow an acceptable practice without making a departure request necessary. The language of the proposed rule was revised to explicitly allow the use of an intermediate liner without a tie-back when used inside an intermediate string. The unusual case of using a combination of surface casing and a liner for a production well is better handled under the provision of § 250.3, Performance requirements.

Comment—There were several comments submitted concerning the use of a liner as production casing below intermediate casing which is addressed at § 250.54(e)(2). All commenters recommended that the specific requirement of lapping 100 feet into the previous casing string be deleted. Their position is based on the reasoning that the performance requirement of 100 feet could cause the lessee to have two strings of casing opposite a potential producing zone.

Response—This recommendation was not adopted. The rule as written provides a minimum specified lap distance. Exceptions can be approved where the lessee can demonstrate why and how a shorter liner lap serves to preserve safety of operations while reaching other operational goals.

Comment—There was one comment of a general nature which recommended that the title of § 250.55 be changed to "Testing of casing" since § 250.55(c) permits a caliper survey to determine casing integrity.

Response—This suggestion was adopted. The content of the paragraph addresses both pressure testing and logging. The paragraph heading suggested is more descriptive of the contents.

Comment—There were many comments submitted concerning the proposed requirement at § 250.55(a) to pressure test all casing strings (except the drive or structural casing) to 70 percent of the minimum internal-yield pressure of the casing. All the commenters would change the proposed requirement and substitute a variety of requirements as follows:

1. Utilize a table of surface pressure test values:

Conductor	200 psi.
Surface	1000 psi.
Intermediate	1500 psi minimum or 0.22 psi/foot.

2. Test to maximum anticipated surface pressure or 70 percent of minimum internal-yield pressure, whichever is less.

3. Utilize a table of surface pressure test values:

Conductor	200 psi.
Surface	1000 psi.
Intermediate	1500 psi.

together with a provision that "the test pressure shall not exceed 70 percent of the minimum internal-yield pressure of the casing including the surface pressure, internal and external fluids, and pressures."

4. Use the proposed requirement and add "or to the maximum anticipated surface pressure to be encountered while the casing is exposed during drilling operations to the next casing point, whichever is less,".

5. Delete the proposed requirement and substitute "500 psi above the pressure to yield an equivalent mud weight at the casing shoe of the estimated fracture gradient plus 1.0 pound per gallon (ppg), or the pressure required to exert a differential pressure across the exposed casing to 50 percent of the minimum internal-yield of the casing, whichever is less." The commenter's reason for recommending changes to the proposed requirement is essentially that testing to the rated capacity of casing that may be used in the string which *exceeds* the design parameters could cause the failure of other casing in the string which *meets* the design parameters.

Response—These recommendations have been adopted by revising the paragraph to require testing to 70 percent of the minimum internal yield pressure of the casing or as otherwise approved or required by the District Supervisor. The OCS Order No. 2, Drilling Operations, placed into effect on January 1, 1980, gave a table of minimum pressure test values for various casing strings. In an effort to find a better approach and reduce the need for, and frequency of departures, the proposed rules set forth for comment another method based on the minimum internal-yield pressure of the casing.

It is concluded that there are acceptable alternate approaches for determining appropriate test values and that greater flexibility than was provided in the proposed rule is warranted. The rule has been revised to permit the District Supervisor to approve alternative tests.

Comment—There were many comments submitted concerning the proposed requirement at § 250.55(b) to test the liner lap to 70 percent of the minimum internal-yield pressure of the casing into which the liner is lapped. The commenters would amend the proposed requirement with a variety of substitutions as follows:

1. Test to 0.22 psi/foot, or maximum anticipated liner-top pressure, whichever is less.

2. Each liner lap shall be tested to 500 psi above the intermediate casing formation fracture pressure, or 2500 psi, whichever requires a lesser surface pressure.

3. The liner shall be tested to the mud weight equivalent expected when performing the leak-off test of the liner shoe, or to 1.0 ppg over the equivalent mud weight test obtained in the leak-off test performed at the casing shoe into which the liner is lapped, whichever is greater. The pressure test should not exceed 70 percent of the minimum internal-yield pressure of the larger casing, including surface pressure, internal and external fluids, and pressures.

4. The casing and/or liner top should be tested to the maximum anticipated leak-off pressure that will be encountered when conducting a formation leak-off test.

5. Add to the proposed requirement "or to the maximum anticipated surface pressure to be encountered while the casing is exposed during drilling operations to the next casing point, whichever is less."

6. Substitute the following requirement with "500 psi above the intermediate casing shoe fracture pressure or 2500 psi, whichever is less surface pressure."

7. Substitute the following requirement: "500 psi above the pressure required to yield an equivalent mud weight at the liner shoe of the estimated fracture gradient plus 1.0 ppg, or the pressure required to exert a differential pressure across the exposed casing equal to 50 percent of the minimum internal-yield pressure of the casing, whichever is less."

Also, a few commenters would amend the proposed requirement to squeeze cement the liner lap, if necessary, and allow other remedial measures, such as use of other materials for squeezing or mechanical means.

Response—In response to these recommendations, § 250.55(b) of the final rule was revised to allow a lower test pressure and to permit remedial actions other than squeeze cementing. Commenters present convincing arguments that the proposed test pressure values may be too high to be in a rule formulated to govern a wide range of applications. It is recognized that the required test pressure must consider mud weight, casing burst strengths, differential pressure across casing walls, fracture pressure at the casing shoe below the liner lap, and fracture pressure at the liner shoe. It is also recognized that squeeze cementing is not the only or necessarily the most appropriate remedial action available to correct an improper liner lap seal. The rule has been revised to clarify that production-liner laps shall be tested to a minimum of 500 psi above the formation fracture pressure at the shoe of the casing into which it is lapped. In addition, a provision was added to test the drilling-liner lap against pressures which would be encountered when conducting subsequent pressure-integrity tests below the liner.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.55(c) to pressure test or evaluate the casing after prolonged operations. Many of the commenters would revise the proposed requirement in some manner in the belief that "30 days" is somewhat arbitrary, other factors such as dog legs, mud properties, etc., are more important and that this requirement does not contribute to the safety of the well. Some commenters thought the proposed requirement adequate. One commenter would specify verifiable repeat sections with accuracies within 0.03 inch, repeatability to 0.02 inch, and circumferential arm spacing not to exceed 0.5 inch, in order to detect maximum wall loss or damage. One commenter would substitute "every 600 rotating hours" for "every 30 days."

Response—These recommendations have not been adopted. From a technical standpoint, casing wear may be more related to actual rotating hours than to the number of hours (days) which have elapsed. However, the use of actual hours of rotation would create a greater recordkeeping and administrative burden than that created by the proposed rule.

Prescriptive rules regarding caliper survey specifications are considered unnecessarily confining to the lessee's freedom to choose survey instrumentation and may stifle innovation.

It is realized that casing wear is a result of many complex and interacting factors and that no definitive formula for general application exists. Reliance must be placed on drilling knowledge, experience, attentiveness to the effect of operations on casing, periodic assessments, and human judgment. The main purpose of the 30-day rule is to alert workers and supervisors to be continuously aware of the effect of operations on casing integrity.

Comment—There were several comments submitted concerning the proposed requirement at § 250.55(d) regarding cement setting times. All the commenters would amend the proposed requirement for holding cement under pressure for 8 or 10 hours in the belief that the formation-integrity test would determine cement integrity and that the

subject holding times have no basis in current technology.

Response—This recommendation was not adopted. If either or both waiting times and compressive strengths are deleted, the amount and type of information otherwise needed to satisfy § 250.54(f)(6) would need to be expanded. Errors such as mistakes in formulation, excesses in proportion, and improper blending of accelerators together with job execution and equipment shortfalls can result in "flash sets," other cement placement failures, and consequent adverse well-control situations even under "current technology."

Comment—There were many comments submitted concerning the proposed requirement at § 250.56(c) on BOP working pressure. Most of the commenters recommended the deletion of the proposed requirement which authorizes an MMS District Supervisor to require an annular BOP with a working pressure above 5000 psi based on the belief that annular preventers are not designed for use at pressures greater than 5000 psi. One commenter noted that the calculated anticipated surface pressure varies between lessees and MMS depending upon the assumptions used. One commenter would correct and clarify the wording of the requirement regarding BOP working pressure exceeding anticipated surface pressure (ASP) to read "to which it may be subjected" rather than the proposed "to which it may be anticipated to be subjected."

Response—The recommendation that the requirement be deleted was not adopted. The rule on annular preventers was revised to clarify that the rated working pressure (RWP) of the annular preventer must exceed the ASP. In those cases where a lessee proposes to use an annular preventer with a RWP that is less than the ASP, the lessee must demonstrate to the District Supervisor under the provisions of § 250.64(f)(3)(ii), that wellbore conditions, operating procedures (e.g. ram-to-ram stripping), or other factors are such that installation of an annular preventer with a higher RWP is not warranted.

The calculated ASP value depends upon a number of assumptions which vary widely because the assumptions are based upon the experiences and biases of the person(s) making the estimate. Estimates involve assumptions that must be made regarding key factors such as formation fluids, pore pressures, fracture gradients, mud gradients, percent of hole filled with mud, and casing points. Varying approaches to the methodology, analytical techniques, and methods of calculation inherently contain elements which require human judgment.

Until more consistent methodologies are developed and field-proven, it would be unwise and disruptive to prescribe specific methods and techniques via regulations. Lessees are asked to submit the basis of their approach together with the calculations used and assumptions made using their best efforts to determine an ASP.

Comment—There were several comments submitted concerning the proposed requirement at § 250.56(d)(1) that the accumulator system provide sufficient capacity to supply 1.5 times the volume necessary to close all BOP equipment with a minimum pressure of 200 psi above the precharge pressure. The commenters recommended clarifying the requirement by adding "without assist from a charging system." One commenter suggested requiring a periodic accumulator-volume test and a minimum output from the accumulator pump.

Response—The recommendations have been adopted in part. Commenters pointed out unclear wording in the proposed rule. The intent of the rule is that the accumulator have sufficient capacity without assist from a charging system. The language was revised for added clarity.

Periodic accumulator-volume and pump-output tests certainly are good operating practice and are done by many operators. The MMS has insufficient cause-and-effect data on failures at this time to justify mandating specific requirements which would require additional recordkeeping, record retention, and inspection burdens without a demonstrable increase in the level of safety.

Comment—There were several comments submitted concerning the proposed requirement at § 250.56(d)(2) for a backup to the accumulator system "which shall be automatic, supplied by a power source independent from the power source to the required accumulator system." All of the commenters would revise the requirement for clarity by using the words "supplied by a power source independent from the power source to the primary accumulator charging system."

Response—The descriptive terms "primary" and "charging" have been added to the text of § 250.56(d)(2) of the final rule as a means of eliminating any ambiguity. To make clear the intent that accumulators be operable at all times, language has been added to require that accumulator regulators supplied by rig air have some device to ensure uninterrupted functional capability in case rig air is lost.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.56(d)(5) to equip both the choke and kill lines with two full-opening valves and that at least one of the valves on each line be remotely controlled. Several commenters recommended amending the requirement to equip the kill line with a 150 check valve in lieu of a remotely controlled valve. This recommendation was based on the view that the remotely controlled valve on the kill line is unnecessary, because the kill line's primary function is to provide means of pumping into the annulus. One commenter suggested that the choke line(s) should be at least 3 inches in internal diameter as per API RP 53.

Response—The text of the rule has been modified to permit the use of a check valve in lieu of a remotely controlled valve on the kill line of a surface BOP system, provided there are two readily accessible manual full-opening valves in place and the check valve is placed between the manual valves and the pump. The requirement for subsea BOP systems remains the same. The proposed rule regarding remotely controlled valves as written applied to both surface and subsea choke and kill lines.

A check valve installed in the kill line of a subsea BOP system would destroy a capability needed in many subsea BOP system configurations to be able to pump down the choke line with returns up the kill line. This capability is important to safety in many situations such as when it becomes necessary to remove kick gas trapped below a closed preventer or when, in an emergency situation, a malfunction or other event occurs which leaves the choke line unusable.

Manual valves, which are normally easily operated, are often inaccessible in emergency situations.

Comment—There were several comments submitted concerning the proposed requirement for installation of a fill-up line above the uppermost BOP. All the commenters recommended that this requirement be deleted as unnecessary and not a part of the BOP system.

Response—This recommendation has not been adopted. It is important that the fill-up line be located above the uppermost preventer to discourage use of the kill line for routine fill-up purposes. A requirement for fill-up lines to the extent that they are a standard and integral part of rig equipment is not considered a burden.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.56(d)(7)(i) that the manifold and choke equipment subject to well and/or pump pressure have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's. All of the commenters would revise the requirement to provide that the subject manifold and choke equipment have a rated working pressure at least as great as the maximum anticipated surface pressure to which it may be subjected. A reason for this view is the potential to utilize a BOP of greater than necessary rated working pressure due to equipment availability.

Response—This recommendation was not adopted. A related concern about required test values being excessively high in some cases because the lessee, for convenience, proposes to use higher rated equipment than is necessary is discussed in response to comments received under § 250.57. It is recognized that, in some cases, higher rated BOP system components, wellhead equipment, choke manifolds, and/or upper parts of casing strings are used than would be required by the regulations for well control. When this is the case, it may be permissible that the equipment pressure ratings and field test pressures as stated in the rules be related to that lower rated equipment which would meet the requirements of the regulations if based on the approved well-control design.

The rule at § 250.56(c)(7)(i) is that the rated working pressure of the manifold and choke equipment be at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor.

Comment—There were many comments submitted concerning the proposed requirement at § 250.56(d)(8) that "valves, pipes, flexible steel hoses, and other fittings upsteam of, and including, the choke manifold shall have a pressure rating at least as great as the rated working pressure of the ram-type BOP's." Several of the commenters recommended revision of the requirement to provide that the upstream equipment have a pressure rating at least as great as the maximum anticipated surface pressure. A reason for this recommendation is the potential to utilize a BOP of greater than necessary rated working pressure due to availability. One commenter would include Coflexip pipe™ or its equivalent for use as choke and kill lines.

Response—These recommendations were not adopted. These situations may be accommodated under the rule as written. Also, § 250.56(d)(8) allows for the use of flexible pipe. See the response to similar comments under § 250.56(d)(7)(i). The rule at § 250.56(d)(8) is revised by adding the phrase "or as otherwise approved by the District Supervisor."

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.56(d)(9) for the wellhead assembly to have a rated working pressure that exceeds the anticipated surface pressure to which it may be subjected. All the commenters recommended revision to base the requirement for the wellhead assembly pressure rating on maximum anticipated surface pressure. The reason for this recommendation is the potential to utilize greater than necessary pressure-rating casing due to present inventory of materials or availability.

Response—The recommendation was adopted to require that the rated working pressure of the wellhead assembly exceed the anticipated surface pressure to which it may be subjected.

Comment—There were several comments submitted concerning the proposed requirement at § 250.56(d)(10)(i) to install a kelly cock below the swivel and also below the kelly. All of the commenters recommended amending the proposed requirement to address the use of top-drive systems. One remotely controlled safety valve (kelly cock) would be installed in this assembly in which there is no kelly. One commenter suggested that a manual valve should be used as a "mud-saver" valve to prevent wear on the remotely controlled upper kelly cock (safety valve).

Response—The provisions of § 250.56(d)(10)(i) of the final rule include requirements for safety valves on top-drive systems and explicit requirements for kelly cocks while drilling with a mud motor on rotary-table drive rigs in the absence of a kelly. Drilling with a mud motor on rotary-table drive rigs in the absence of a kelly creates functionally the same need for kelly cocks as if a kelly were in use.

Some operators with top-drive systems routinely use a remotely controlled valve as a mud saver. The frequency of opening and closing of a valve when used for this purpose causes a rapid rate of wear and deterioration. This decreases the dependability of the valve and hydraulic system for use as a safety closure device below an acceptable level of safety.

By virtue of design, some remotely controlled valves are not satisfactory as safety valves when used alone. Choke manifold valves represent an inferior backup because valve closure exposes the swivel assembly and hose to well pressure. Installation of a second valve of a kelly cock type, either manually or remotely controlled, is considered necessary.

Comment—There were several comments submitted concerning the requirements at § 250.56(d)(10)(ii) to have drill-string safety valves in the open position on the rig floor to fit all connections in the drill string. All commenters recommended changing the proposed requirement to permit the use of crossover connections to comply with this proposed requirement.

Response—This recommendation was not adopted. The use of crossovers is of minimal value toward reducing the net number of pieces kept on the floor, may increase the length and weight of the device, and make emergency installation difficult. Stripping in and out with crossovers whose inside and outside diameters are at variance with those of the drill string and/or valves without due cause is not considered good operating practice.

Comment—There were several comments submitted concerning the proposed requirement at § 250.56(d)(10)(iv) to install locking devices on the ram-type BOP's. All commenters would relocate the requirement as a new subparagraph, 250.56(d)(11), with the view that these devices are an integral part of the BOP and not a system component.

Response—The recommendation was adopted. Proposed subparagraph 250.56(d)(10)(iv) was rewritten as 250.56(d)(11) of the final rule.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.56(e)(1) on subsea BOP's. Several commenters recommended deletion of the sentence requiring subsea accumulator-type closing units on the basis that the subject closing unit is not the only way to close subsea BOP's quickly and would not ensure closure in the event of loss of hydraulic fluid. The commenters also recommended the deletion of the District Supervisors' authority to require a subsea BOP to be installed before drilling below conductor casing. One commenter would address the subject of closing the BOP where the BOP is run on conductor casing while drilling the surface hole. This commenter would include pilot holes in water over 500 feet deep (without use of a riser) for safety reasons.

Response—These recommendations were adopted in part. At shallow water depths and some other situations, a sufficiently fast closure rate is obtainable without employing subsea accumulators. Loss of hydraulic fluid

may or may not result in loss of control function depending upon equipment design and the point(s) of equipment and/or hydraulic failure. The text of § 250.56(e)(1) of the final rule has been revised to make clear that the District Supervisor may approve alternate approaches when justified.

It is understood that installation of a BOP stack on conductor casing is common industry practice and has been fully accepted by MMS. Lessees commonly install BOP's on conductor casing for reasons of convenience and not to provide capability to close the preventers on a kick. Closing in on a kick may cause new fractures or the opening of existing fractures at the conductor shoe resulting in uncontrolled flow through the fractures to the surface. For these reasons, this rule was written to recognize that the installation of a BOP stack is not required on a conductor unless, for example, the conductor is to be set deep where closure of the BOP on a mild kick may be a practical safety measure.

Comments—There were many comments submitted concerning the proposed provision at § 250.56(e)(2) to require the BOP system to include operable dual-pod control systems when drilling below surface casing, and "each control pod shall contain all valves and regulators necessary to ensure proper and independent operation of the BOP system function and to prevent movement of the hydraulic fluid between the two control pods."

All the commenters recommended that the proposed requirement be revised to provide that "the BOP system shall include operable dual-pod control systems necessary to ensure proper and independent operation of the BOP stack functions when drilling below surface casing." This recommendation is based on the shuttle valve location which is not in the pods; the reference to "all" is therefore inappropriate. One commenter observed that this requirement would cause drilling operations to be halted while repairs are made to the control pods and that this would be an excessive cost to operations.

Response—These recommendations were adopted in part. The text of § 250.56(e)(2) has been rewritten to more clearly describe the requirements to be met.

It is recognized that in some cases, the marine riser may have to be pulled and rerun in order to repair the pods and that the proposed rule would require that drilling operations be suspended while repairs are made. These are uncommon occurrences. Depending on total circumstances including well and wellbore status, and whether the well is fully cased a or new hole is to be drilled, the District Supervisor may approve a departure provided certain specified conditions of approval are met.

Comment—There were several comments submitted concerning the proposed requirement at § 250.56(e)(3) to displace the marine riser with seawater prior to its removal and to maintain sufficient hydrostatic pressure within the wellbore to maintain a safe well condition. The commenters recommended that the requirement be revised to allow for other suitable precautions, such as mechanical or cement plugs, to be taken to maintain a safe well condition, since a low fracture gradient at the casing shoe would preclude the use of mud hydrostatic to contain well pressures.

Response—Section 250.56(e)(3) has been revised to allow the use of other alternatives.

Comment—There were a few comments submitted concerning the proposed requirement at § 250.56(g)(3) that surface BOP's servicing a tapered drill string, and with only two sets of conventional pipe rams of one size, must have shear rams and a crossover sub to the smaller drill pipe size, which is to be readily available. The commenters recommended deletion of the proposed rule or the amendment of it to require that the small size or variable-bore pipe rams be used to close in on the smaller drill pipe since installing a crossover sub is time consuming and is highly undesirable during well flow.

Response—Proposed § 250.56(g)(3) was deleted. Section 250.56 (g)(1) and (g)(2) of the final rule provides conciseness in language and the proper degree of flexibility in compliance. When shutting in a well, it is faster and, therefore, safer to utilize a ram which seals directly on the pipe rather than picking up a crossover sub and making it up on the drill pipe before ram closure. Proposed § 250.56(g)(3) has been in OCS Order No. 2 since 1980. Its purpose was to exempt a few older rigs and BOP systems from a requirement which would require major and costly structural changes to allow for the increased BOP system height or replacement of ram preventer bodies which could not be retrofitted with variable bore rams. This exemption is no longer considered justifiable.

Comment—There was one comment of a general nature submitted concerning the proposed requirements of § 250.57. The commenter recommended that all operations such as abandonment and BOP tests be monitored by MMS inspectors.

Response—The recommendation has not been adopted. The MMS does not have the staff to witness all tests and special operations and relies on an inspection program designed to maximize the effectiveness of inspection efforts over a wide area by scheduling complete inspections of each facility once a year and by conducting periodic unannounced inspections of selected operations on a random basis.

Comment—There were many comments submitted concerning the proposed requirements at § 250.57(b) to test surface ram-type BOP's and the choke manifold to no less than 70 percent of the minimum internal-yield pressure of the casing and to test the annular BOP to 70 percent of its rated working pressure or 70 percent of the minimum internal-yield pressure of the casing, whichever is less. One commenter suggested that surface BOP stacks should be tested with water.

Other commenters recommended various changes to revise the rule to require the testing of BOP's and choke manifold to:

1. The anticipated surface pressure.
2. The anticipated surface pressure or 70 percent of the minimum internal-yield pressure, whichever is less.
3. The lesser of:
   a. The rated working pressure of the BOP's,
   b. The rated working pressure of the wellhead, or
   c. 70 percent minimum internal-yield pressure of the casing.

The commenters would revise the requirement and suggest testing the annular BOP to:

1. Anticipated surface pressure or 70 percent of its rated working pressure.
2. Anticipated surface pressure or 70 percent of its rated working pressure or 70 percent of the minimum internal-yield pressure of the casing, whichever is less.
3. As required for ram-type BOP's, except that the test pressure need not exceed 70 percent of its rated working pressure.

The commenters' views were that 70 percent of minimum internal-yield pressure of the casing could cause excessively high test pressure on other components if higher than design strength casing is installed because it is more readily available. One commenter would clarify the requirement as to whether the test pressure is calculated at the casing shoe or casinghead.

Response—The recommendations that the rule be revised from testing to BOP rated working pressure to testing to anticipated surface pressure were not adopted. However, to recognize that alternate methods of arriving at BOP test pressures may be acceptable, the rule is revised to require that surface

ram-type BOP's be tested to their rated working pressure or as otherwise approved by the District Supervisor and that surface annular preventers be tested to 70 percent of their rated working pressure or as otherwise approved by the District Supervisor. A recommendation that surface BOP stacks be tested with water because the use of water increases the validity of the test results as compared to test results when mud is used has been adopted.

Responses to the substance of the commenters' concerns appear in the discussion of § 250.56(d)(7)(i).

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.57(c) to test subsea BOP's after installation to 70 percent of the minimum internal-yield pressure of the casing. All of the commenters recommended that the proposed requirement be revised in a manner similar to that suggested for the testing of surface BOP systems. They recommended revising § 250.57(c) to require testing to maximum anticipated surface pressure on subsea ram-type BOP's (or to 70 percent minimum internal-yield pressure of the casing, whichever is less) and subsea annular BOP tests to 70 percent of its rated working pressure. Their rationale was the same as expressed in comments on testing surface BOP's.

Response—To provide for consistency with the revisions made for surface BOP system test pressures, the proposed rule was revised to state that BOP test pressures be related to rated working pressure or as otherwise approved by the District Supervisor. This revision allows the lessee flexibility in the method used in arriving at BOP test pressure values.

Comment—There were several comments submitted concerning the proposed requirements at § 250.57(d) to test kelly cocks and safety valves weekly to pipe-ram test pressure and to actuate casing valves prior to running casing. All commenters would clarify that the casing safety valve could be equipped with the proper connection to fit the casing in use. Due to wear potential and length of time for replacement, one commenter suggested a monthly test for safety valves on top-drive systems, excluding the remotely controlled safety valve.

Response—The recommendation to revise pressure-test criteria was amended to state that choke manifold valves, upper and lower kelly cocks, top-drive safety valves, inside BOP, and drill-string safety valves be pressure tested to pipe-ram test pressures or as otherwise approved by the District Supervisor. The recommendation to amend test frequency requirements was not adopted because these devices are all important components of well-control equipment. Considering that many wells are drilled within 6 weeks, a 7-day test frequency on these components imposes minimal wear and cost factors. Inspection reports by MMS personnel indicate a tendency toward laxity in the care, maintenance, and availability of these valves. Regarding the Varco™ valve used as a mud saver, other components could be added to the string to serve this function or the valve may be redesigned.

Comment—Several commenters noted that the last sentence in § 250.57(d) could be interpreted as requiring a full-opening casing safety valve and recommended that the sentence be revised.

Response—The recommendation was adopted and the last sentence was revised accordingly.

Comment—There were several comments submitted concerning the proposed requirements in § 250.57(e)(3) to test subsea and surface BOP's.

All the commenters recommended that the text of the proposed requirement be amended to clarify that pods and control stations are different equipment and to delete the reference to a dual-system accumulator. They also recommended deletion of the provision to allow each crew to perform the test, due to less than rigid scheduling of BOP tests. One commenter would delay testing when logging or casing-setting operations are in progress. One commenter suggested that the last sentence in § 250.57(e)(3) regarding blind rams and blind-shear rams should read, "These rams need to be pressure tested only when installed and prior to drilling out after each casing string has been set for surface BOP stacks, and prior to drilling out after each casing string has been set or within the preceding 7 days for subsea BOP stacks."

Response—These recommendations were adopted in part. The text in § 250.57(e)(3) was modified to clarify that reference to dual-system accumulators is not intended. The phrase "if either control system" was replaced by the phrase "if either control station or pod."

Well-control safeguards must be operable during logging operations, particularly in open hole or if the casing is perforated. While it is true that BOP testing while casing is being run and cemented would be impractical, the proposed rule allows flexibility in scheduling tests. Lessees can schedule BOP tests to avoid having a test deadline occur during the running or cementing of casing.

The BOP pressure testing is necessary before drilling out from under a casing shoe because during the 7 days preceding readiness to drill out, the blind and/or blind-shear BOP assembly and controls may have been subjected to considerable use or abuse and reliability must be ascertained before proceeding.

Comment—One commenter agreed with the requirement in § 250.57(e)(4) for function testing of blind and blind-shear rams as part of the weekly BOP stack test.

Response—No response is necessary.

Comment—There were a number of comments submitted concerning the proposed requirement at § 250.57(e)(5) to test variable-bore pipe rams against both sizes of pipe. Based on the view that testing is already required, all the commenters recommended that the proposed requirement be deleted, the lessee should be able to use the pipe in the BOP stack at the time of testing, and testing on each pipe size is unnecessary. One commenter would specify that only the larger size pipe be used for testing. One commenter recommended testing only when variable pipe-bore rams are used for operations described in § 250.56(g) (when actual drilling operations are in progress).

Response—These recommendations were not adopted. However, the proposed rule was revised to specifically exclude drill collars and bottomhole tools from the testing requirements. The proposed rule is intended to apply to all sizes of pipe being used in a tapered string with the exception of drill collars and bottomhole tools.

Comment—Several comments were submitted concerning the proposed requirement in § 250.57(e)(6) to test BOP's or the wellhead following disconnection or repair of pressure containment seals. The commenters recommended amendment of the proposed requirement to limit testing to the seal which was affected by the repair or disconnection. One commenter would revise the rule to test to the maximum anticipated surface pressure or 70 percent of minimum internal-yield pressure of the casing, whichever is less.

Response—The recommendation to limit testing to the affected component has been adopted and the text of the proposed rule has been revised accordingly.

The recommendation to revise the proposed rule to require testing to anticipated surface pressure as an

alternative to 70 percent of minimum internal-yield pressure was not adopted.

Comment—There were several comments submitted concerning the proposed requirement in § 250.57(f) to inspect BOP systems and the marine riser daily. The commenters recommended the deletion of this proposed requirement, based on the lack of support for this provision by experience, and that the requirement would be time consuming and only large leaks would be detected by television. One commenter would clarify that "riser" does not mean the casing riser used on bottom-supported rigs but refers to the marine riser on subsea BOP's.

Response—The rule is revised (1) to require inspections of marine risers on dynamic-positioned rigs only upon a determination by the District Supervisor that circumstances warrant an inspection(s) and (2) to clarify that the required inspections do not apply to casing risers on either bottom-supported drilling units or structures. In other than dynamic-positioned rigs, routine daily inspections of the marine riser by underwater television is considered a worthwhile practice even though no symptoms of a problem have been manifested at the surface. Small mud leaks, riser deformation, and other early warnings of incipient problems may not be manifested at the surface and may go unnoticed if observations are made only at the surface. Since BOP systems must be inspected daily, the modest incremental cost of including the riser in the underwater television survey is more than offset by the potential benefits. Inspection of the marine riser in dynamic-positioned rigs would require the use of remotely operated or manned vehicles. The routine daily use of these vehicles would increase costs substantially and, as a rule of general applicability, a requirement for daily inspections is considered unwarranted at this time. Nevertheless, it should be understood that the District Supervisor has the authority to require periodic inspections when it is determined that circumstances warrant that action. Section 250.57(f) of the final rule was also revised by deleting the reference to manufacturer's recommendations as acceptable guidelines for compliance.

Comment—There were a number of comments submitted concerning recording of all pressure tests, actuations, and inspections of the BOP and related systems, system components, and marine risers as provided in § 250.57(g). The commenters recommended revision of the proposed regulation to exclude marine riser inspections. Their comments relative to § 250.57(f) reflect their rationale to delete riser inspections.

Response—These recommendations were not adopted. Inspections of marine risers by underwater television can be combined with the daily underwater television inspections of the BOP system. The results of all inspections must be recorded even though the specific inspection may not have been required by the regulation.

Comment—There were several comments submitted concerning proposed § 250.58(b) providing for well-control test drills to be required by an MMS representative. The commenters recommended revision of the proposed requirement to conduct test drills during periods selected to minimize endangering the operations in progress. In general, the commenters objected to the authority of the inspector to require a well-control drill at any time. One commenter recommended that requirements for drills be limited to the point of completion of the initial actions.

Response—The proposed rule has been modified to clarify what may be required. The phrase "at any time during the drilling operations" has been deleted from the rule, and the phrase "after notifying and consulting" has been changed to "after consulting." It is MMS's policy and practice that only authorized MMS representatives are permitted to require a lessee to conduct unscheduled well-control drills. Once a drill is called for, it should be carried through to completion. Initial actions are an important part of a drill but are not considered sufficient to satisfy a standard to maintain fully trained personnel.

Comment—Several comments of a general nature were submitted concerning the proposed requirements for diverter systems in § 250.59. A few commenters recommended deletion of the proposed detailed specifications. They would utilize a performance-oriented approach. The API draft document on diverter systems would be used as a base on which to develop performance-oriented requirements. One commenter recommended adding a paragraph (h) which would allow the diverter unit and/or vent line to be positioned subsea, subject to approval by the District Supervisor. Another commenter essentially supported the proposed requirements regarding line size, number of turns, use of remote-controlled and full-opening valves, and advocates proper design, selection, installation, maintenance, function 170 testing, enforcement, well planning, and personnel training on the diverter system.

Response—These recommendations were not adopted. The data available to MMS do not support a claim that diverters have performed fairly well under a wide variety of operating conditions. Data available to MMS on diverter failures indicate that more than one-half have failed to perform satisfactorily upon demand. The nature and variety of the over-pressured situations for which diverter systems serve as a "safety valve" limits the use of the performance standard approach. Performance standards for diverter systems that would assure the safety of operations would need to be worded in a way that requires the use of specific minimum size diverter lines (e.g. 10 inch and 12 inch diverter lines). The text of the final rule simply specifies these minimum sizes. The draft API RP document will be reviewed when it becomes final. At that time consideration will be given to the adoption of the requirements in that document or portions thereof. Under § 250.3 a lessee/operator may obtain approval for the use of a diverter system which would provide equal or better protection than a diverter system which meets the minimum design specified in § 250.59. The rule has been revised to provide a 2-year period for compliance with the new diverter requirements.

Comment—There were a few comments submitted concerning the proposed requirement in § 250.59(a) to install a diverter system when drilling both conductor and surface hole from floating drilling operations, unless otherwise approved by the District Supervisor. The commenters pointed out the undesirability of bringing gas up the riser to the drilling facility and recommended flexibility in dealing with well control prior to setting conductor casing. One commenter recommended the addition of language to this paragraph which would allow removal of the diverter (annular sealing assembly) if a pilot hole is drilled and the hole is stable, in order to perform hole-opening operations prior to running casing. One commenter recommended that language be added to the proposed rule to address the situation where the subsea BOP is run before drilling surface hole. The diverter system would be inoperable if the subsea BOP were closed.

Response—These recommendations were not adopted. The situations described by the commenter are better handled on a case-by-case basis. The diverting of an uncontrolled flow into the ocean to avoid the flow of gas at the surface may or may not be the better

choice, depending upon the particular circumstances.

The recommendation to revise the rule to allow rigging down the diverter system to open the hole was not adopted on the grounds that the increased exposure to risk is not justified.

Comment—There were numerous comments submitted concerning the proposed requirements in § 250.59(c) for the diverter system to include remote-controlled valves in flow lines, limit the number of turns to two in the flow path, utilize a minimum radius of curvature of three pipe diameters in any turn, install fail-safe open automatic valve actuators, and protect the system controls and control lines from damage. The commenters recommended revision of the rule to require a "minimum" number of turns in the flow path, delete minimum radius of curvature, delete the requirement for fail-safe-open automatic valve actuators, and clarify the language regarding protection of system controls and lines. One commenter recommended 90-degree turns which are "targeted."

Response—These recommendations have been adopted in part and the paragraph revised to read:

(c) The diverter system shall be equipped with remote-controlled valves in the flow and vent lines that can be operated from at least one remote-control station in addition to the one on the drilling floor. Any valve used in a diverter system shall be full opening. No manual or butterfly valve shall be installed in any part of the diverter system. There shall be a minimum number of turns in the vent line(s) downstream of the spool outlet flange and the radius of curvature of turns shall be as large as practicable. All right-angle and sharp turns shall be targeted. Flexible hose may be used for diversion lines instead of rigid pipe if the flexible hose has integral end couplings. The entire diverter system shall be firmly anchored and supported to prevent whipping and vibration. All diverter control instruments and lines shall be protected from physical damage from thrown and falling objects.

Comment—There were many comments submitted concerning the proposed requirements in § 250.59 (d)(1) and (d)(2) regarding spool outlet size, branch lines for downwind diversion, and diverter line sizes. The commenters recommended use of the term "wellhead" rather than "BOP" for clarity. Several commenters recommended a decrease in the proposed minimum line and spool sizes, and others would increase the minimum line size to 12 inches. The advocates of smaller sizes believe that, from past experience, spool outlets and lines of 6-inch diameter and branch line diameters of 6 inches are adequate and states that it would be costly to comply with the rule. One commenter would add that diverter units that serve also as BOP's should comply with the annular type BOP design requirements specified in Section III G3 of API Spec 16A.

Response—The recommendation to substitute "wellhead" for "BOP" was adopted. The remaining recommendations were not adopted. There are occasions when the lessee elects to retain a diverter system above the BOP after surface casing is set. However, this is not a requirement. The information available to MMS does not support the belief that diverters have performed well. The API Spec 16A is not considered applicable as a basis for low-pressure annular preventers used only for flow-diversion purposes.

Comment—There were several comments submitted concerning the proposed requirement in § 250.59(e)(1) to equip a one-spool outlet system with branch lines for downwind diversion. All of the commenters recommended revision of the proposed requirement so that branch lines would not be required on dynamically positioned drill ships.

Response—The recommended revision was adopted and the proposed rule was revised accordingly. The rule allows for branch lines off of a single spool. The heading of a dynamically positioned drill ship can be controlled so as to be into the wind. In this case, downwind diversion capability can be provided with only one vent line.

Comment—There were many comments concerning the proposed requirement in § 250.59(e)(2) to utilize 12-inch diverter spools and lines. Several commenters recommended revision of the proposal to require two 6-inch spools and lines or a single spool outlet with flow area equivalent to two 6-inch diameter lines and full-opening valves. One commenter agreed that line size should be at least 12 inches. The former commenters believed that their recommended sizes have proven adequate in the past and that to refit would be costly.

Response—The recommendations have not been adopted. The MMS has no evidence supportive of a requirement which would allow smaller spool or line sizes.

Comment—There were numerous comments submitted concerning the proposed requirement in § 250.59(f) to actuate the diverter system and flow test the lines. Several commenters recommended revision of the rule to require a pressure test when nippled up on conductor casing, require actuation prior to spud, and delete the proposed daily actuation and flow tests. One commenter recommended a functional test when installed and weekly thereafter. The commenters believed daily actuation and flow tests will cause wear to the sealing element and deposit cuttings in the system lines.

Response—The text and requirements in § 250.59(f) have been revised to differentiate between surface conductor diverter systems and other surface wellhead and subsea configurations and to require that diverter systems on surface wellhead and configurations be pressure-tested to 200 psi when nippled up on conductor casing. Daily function testing is not considered excessive after taking into account the short period of time a diverter is required during drilling of the well. Further, flow tests serve to clear mud, cuttings, and other obstructions from the diverter system lines.

Comment—One commenter recommended adding a new § 250.59(h) to permit the use of subsea diverters.

Response—The recommendation was not adopted. Subsea diverters involve a new technology that is being evaluated by MMS. Subsea diverter systems may be permitted on a case-by-case basis as alternative technology in § 250.3.

Comment—Several commenters recommended that the entire text of § 250.60(b)(1)(iii) be deleted. Their position was that drilling fluid programs are variable and change due to well conditions, and specified ranges and tests may not apply. They believed that the lessee can best determine the acceptable drilling fluid to accomplish desired wellbore conditions.

One commenter recommended the paragraph be changed to read "Mud properties are suitable for tripping" and "are within the specified ranges required by the mud program." They believed the mud program as approved may change as the well is drilled.

Response—Section 250.60(b)(1)(iii) was revised by deletion of the phrase "in effect at the time." It is recognized that the lessee's mud program is subject to modification during the course of drilling and that the ranges in mud properties specified far in advance of actual drilling operations may not continue to be applicable. The intent of the rule is to recognize that mud properties are to be monitored continuously and corrections made if and when needed. Mud is to be properly conditioned and suitable for tripping before proceeding with any trip.

Comment—Several of the commenters recommended deleting § 250.60(b)(2)

requiring the driller to note the circulation of mud in the hole. They claimed that the requirement has no benefit and should be deleted.

Response—This recommendation was not adopted. This record of mud circulation is useful for retrospective analysis of causes of well-control problems and as a supervisory control over performance.

Comment—One commenter claimed that the requirement in § 250.60(b)(3) for filling the annulus with mud when 5 stands of drill pipe have been removed in no way relates to the 75 psi or any other logical requirement. When 10 stands of 5-inch pipe are pulled from a 12¼-inch hole, the hydrostatic head is reduced by only 22 psi. The commenter recommended, however, that there be some provision for continuous filling of the hole from a trip tank.

Response—The proposed rule was not changed. The rule for 5 stands is based on the practicalities under field conditions where the hole may change from taking to making fluid. Pulling and running drill pipe can destabilize the hole by a "swabbing" action on the wellbore. The time required to pull 5 stands is considered to be an appropriate time lapse between separate measurements of the amount of fluid required to fill the hole for purposes of comparison against pipe displacement volumes. Continuous-fill trip tanks are acceptable provided equivalent regular measurements, checks, and balances are made on pipe displacement volumes versus volumes of fluid required to fill the hole.

Comments—All of the commenters recommended that § 250.60(b)(4) be deleted. They noted that the control of pipe running and pulling speeds to preserve stability of the hole requires discretion, judgment, and adjustments to fit the prevailing conditions. They claimed that it is already an industry practice but is subject to differing interpretations by drilling crew members and not an item which is enforceable under a regulation.

Response—These recommendations were not adopted. It is recognized that selecting proper running and pulling speeds requires knowledge of hole conditions and judgment. Nevertheless, swabbing and surging remain the most common primary causes which lead to loss of well control. Flagrantly excessive running and pulling speeds are recognizable, and compliance at these extremes is enforceable.

Comment—Some commenters on proposed § 250.60(b)(6) stated that having the maximum pressure to be contained under the BOP posted near the driller's control panel as required in this paragraph could lead someone to open the choke when this pressure was exceeded while the well condition was actually safe. Opening the choke would reduce the back-pressure on the formation and thus allow additional formation fluid to flow into the wellbore creating another kick, and compounding the existing problem. For these reasons, the commenter recommended that § 250.60(b)(6) be deleted.

One commenter agreed that the maximum allowable pressure should be posted but accompanied by further explanation as to under what conditions the pressure applies, e.g., to prevent formation breakdown or to prevent burst of casing.

A few commenters recommended deleting the entire paragraph because they believe indiscriminate use of the posted maximum pressure could create problems with misapplication. They stated that the maximum pressure to be contained under the BOP is dependent on a number of variables and could change due to a change in well conditions. The plan to bleed excess pressure through the choke during well-control operations should be carefully reviewed and approved by the lessee as a part of the well-control plan.

One commenter expressed the belief that if the well can be shut in and stabilized, the casing seat pressure will decrease or increase only slightly until the influx reaches the casing seat, provided the bottomhole pressure remains constant. As the influx passes the casing seat, the pressure at that point will decline and then remain constant, regardless of the surface pressure. Limiting casing pressure for fear of leak-off will most likely result in a hydrostatic pressure drop and allow further influx of fluid from the kicking zone. They recommended that the regulations clearly define the casing limits and lessee options. The value to be posted on the driller's control panel should be defined as a maximum of 80 percent of the casing internal-yield pressure. A lesser value may be required by the APD or from results of a casing integrity survey.

Response—The recommendation to delete § 250.60(b)(6) was not adopted. However, the phrase "before controlling excess pressure by bleeding through the choke" was deleted. The portion of the proposed rule which would require the value of maximum allowable pressure be posted near the driller's control panel and which identifies the maximum pressure to be contained under the BOP before bleeding through the choke failed to make clear the circumstances under which bleeding would be an appropriate action. The posting of the maximum pressure should include appropriate explanations to assure a clear understanding by users of its use and implications. The posting of a maximum allowable pressure is considered of value and was not deleted. The lessee remains under an obligation to include the maximum pressure to be contained under the BOP with respect to each casing string as a factor in well control contingency plans.

Comment—Many commenters recommended deleting the reference to hydrate zones in § 250.60(b)(7). They claimed the technology does not currently exist for total control of hydrates. This type of drilling is highly specialized and must be planned and effected on a case-by-case basis. Mud temperatures may not need to be controlled.

Response—Section 250.60(b)(7) has been revised to permit measures of safety to be utilized other than monitoring or control of drilling fluid temperatures. Permafrost and hydrate zones exist in the OCS. Mud-program design and well control in permafrost and hydrate zones are more appropriately customized to fit site-specific conditions and are better handled on a case-by-case basis as the commenters noted.

Comment—Many commenters recommended that § 250.60(b)(8) be revised to require the installation of an operable degasser prior to commencement of drilling operations for use throughout the drilling of the well. They believed degasser equipment may not be necessary during well-completion operations.

Response—This recommendation was adopted. Once casing has been set and all zones have been cemented off, an influx of formation fluid would not be expected to occur. Therefore, if completions are defined as operations after production casing has been set and cemented, degassers may not be needed. The text in § 250.60(b)(8) of the final rule has been revised accordingly.

Comment—One commenter suggested an alternative to the procedures in § 250.60(b)(9) would be to bullhead kill fluids back through the drill-stem test tools in order to push produced fluids back into the formation. They stated that there are cases where lost circulation exists after drill-stem tests and mud/fluid circulation is not possible. The attempt to circulate would merely push oil and gas into the annulus.

One commenter recommended that there should be a provision for pulling drill pipe "to the fluid" after a drill-stem test that does not flow to the surface.

Response—Section 250.60(b)(9) was revised to recognize that bullheading test fluids back into the source formation with a kill fluid pumped through the test tools is an acceptable procedure in those cases where circulation of the well-control fluid is not possible.

The commenter who suggested a provision for pulling pipe "to the fluid" did not indicate a procedure for safe and pollution-free disposal of the fluids after they are brought to the surface. Provisions which allow for such situations appear in § 250.3.

Comment—A few commenters recommended that the phrase "and other tests as may be deemed necessary by the District Supervisor" in § 250.60(c)(1) be deleted. They believe the operator should determine which tests are necessary for mud quality and control and that onsite judgment is necessary to do so.

Several commenters recommended that the entire text of § 250.60(c)(1) be deleted or revised. They believed that the lessee is the best authority to determine what testing equipment is necessary and what tests are required for proper evaluation of the drilling fluid system. They did not believe that the District Supervisor is in an appropriate position to prejudge or determine onsite what drilling fluid tests are needed and the testing frequency required. They recommended that the revised rule include performance-oriented requirements for having testing equipment available at the rig site, specifying that appropriate tests be conducted and recorded in the driller's report.

Response—The recommendations were not adopted. Mud properties and conditions are the first line of protection against loss of control over the well. The District Supervisor must retain the authority to order tests to be made on mud characteristics and condition based upon a determination that such tests are needed.

Comment—Several commenters suggested the word "accurately" be deleted from § 250.60(c)(2)(ii) because the word is too open to interpretation, and the word "used" clarifies the function of the device.

Response—The recommendation was not adopted. The accuracy of measuring devices is important. Simple deletion of the word would not resolve the commenters' expressed concerns about openness to interpretation.

The intent of the rule is that the measuring device be of sufficient accuracy to suit the purpose for which the information is used. Neither precision at a laboratory level nor crude approximation is intended. Attempts to quantify the word "accurately" would lead to lengthy and detailed specifications and would be contrary to the concept of performance standards.

Comment—Several commenters recommended that § 250.60(c)(2)(iii) be revised to read, "Mud-return indicator with a visual and audible warning device, and." They claimed that a mud-return indicator is simply a warning device used to sense whether drilling fluid returns are present. Therefore, the mud-return indicator equipment cannot determine quantitative flow rates, and the reference to volumes should be deleted.

Response—These recommendations were adopted in part. The device referred to is envisioned to be a flowline sensor, alternately known as a "flow/no flow," "flow show," and "mud-return indicator" which can be combined with pump discharge rate measuring devices to indicate a relationship between mud input and mud output. The first sentence in § 250.60(c)(2)(iii) of the final rule has been revised.

Comment—Several commenters expressed a belief that the quantity of mud required in § 250.60(d)(1) should be left to the discretion of the lessee who will be exposed to economic loss if adequate mud volume is not maintained.

Several commenters would delete the entire text of § 250.60(d)(3). They believed that the reference to "sufficient quantities of mud and materials" is too open to individual interpretation. The maintenance of well control is covered in § 250.50 where it states, "The lessee shall take necessary precautions to keep its wells under control at all times."

Response—These recommendations were not adopted. "Sufficient mud quantities," standing alone is open to interpretation. Section 250.64(f)(7) of the final rule requires the lessee to propose in the APD the mud quantities to be kept at the site. In the approval process, the District Supervisor considers drilling and wellbore conditions, geographical location, nearness to sources of resupply, and infrastructure factors. Section 250.50 is written in general terms and lacks the specificity required for this important well-control requirement.

Comment—One commenter desired clarification of the use of the word "following" in § 250.60(e). The use of the word "following" in the proposed rule seems to raise some questions as to what is and what is not required during the first year after the effective date.

Several commenters desired clarification of "enclosed mud-handling areas." On many rigs, the solids removal area is typically open on one or more sides. However, during bad weather, tarps are often erected, and this could be interpreted as an enclosed mud-handling area. Also, this section appears to overlap into USCG regulations for enclosed-mud areas in the barge area of the rigs.

One commenter claimed that this is an example of two Federal Agencies writing independent regulations on the same subject, i.e., safety precautions in enclosed mud-handling areas. They also claimed that pressure-sensitive alarms are not reliable or practical. They further stated that if MMS believes that the USCG regulations are inadequate, input to the USCG is appropriate.

Response—Section 250.60(e) of the final rule has been modified to make clear the date when the listed requirements become effective and to indicate that current requirements will remain in effect until that date.

Since the proposed regulations were written, an API committee has been actively reviewing API RP 500B which classifies areas based on their potential for the accumulation of combustible concentrations of gases. The MMS adopted API RP 500B for production operations under Subpart H. To retain consistency between the drilling and production regulations, the MMS has revised Subpart D to reference the ventilation specifications found in API RP 500B. The RP is similar to the USCG existing rule for ventilation on MODU's and does not pose any substantial conflicts with those requirements, while providing similar requirements for structures and facilities that are not subject to USCG jurisdiction.

The MMS believes that the capability to prevent the buildup of combustible concentrations of gas which may be released from the mudhandling system is necessary to mitigate a serious threat to human life and safety on a drilling unit. Accordingly, § 250.60(e) requires that all mud-handling areas which are classified as per API RP 500B where dangerous concentrations of combustible gas may accumulate, shall be adequately ventilated. This requirement is consistent with USCG regulations.

It is recognized that clarification of "enclosed mud-handling areas" is desirable. However, the multiple factors which affect the ability of an area to accumulate dangerous concentrations of combustible gas, including airtight seals, number and sizes of accesses, amount of ventilation available, and adequacy of circulation make it difficult to define an "enclosed area" for the purpose of establishing minimum ventilation requirements. To clarify the intent of the

§ 250.60(e), the term "enclosed" has been deleted and minimum ventilation requirements have been established for mud-handling areas which can be achieved by either natural or artificial means. This provides for a minimum level of safety in mud-handling areas.

Recognizing that areas which achieve the minimum requirements through natural ventilation may not be maintained at a negative pressure, only those areas using mechanical ventilation are subject to negative pressure requirements. The regulations do not prohibit the use of tarps or other temporary barriers for use as windbreaks, etc., providing these barriers do not result in a level of ventilation by natural or mechanical means which is below the minimum required for safety of operation.

The USCG in 46 CFR Part 108 "*Design and Equipment*" addresses, in part, classified locations and "ventilation for enclosed classified locations." The USCG regulates these items for MODU's. The USCG plans to introduce similar rules for all other manned/fixed platforms and structures on the OCS. Once USCG rules are in place and applicable to other drilling units (e.g., landtype rigs used on gravel islands, ice islands, arctic structures, MODU's which have their jacking equipment removed, and other fixed/bottom founded platforms), MMS will evaluate the need to modify its requirements for those facilities.

The MMS continues to work with the USCG in an effort to update existing MOU's addressing the separate and overlapping areas of responsibilities of the two Agencies.

Comment—Several commenters recommended revising the § 250.60(e)(1) to read, "Be ventilated with high-capacity mechanical ventilation systems capable of replacing the air once every 5 minutes while drilling fluid is being circulated." They suggested that the revision would provide a simple, inherently safe area which would be well-ventilated during drilling fluid circulation. The safety of the area would not be dependent on equipment responding to an alarm from gas detection equipment.

Response—Section 250.60(e)(1) has been revised to include the recommended change as an acceptable alternate approach. The revision provides for simpler and inherently safer operations. However, in the arctic, a required high-capacity ventilation circulating system would create an enormous heating requirement to keep the circulating mud from freezing during the winter.

Comment—Several commenters recommended deleting the last sentence in § 250.60(e)(2) which requires pressure-sensitive alarm equipment on the grounds that this equipment is difficult to maintain at offshore locations.

Response—Section 250.60(e)(2) of the final rule has been revised to permit the use of open-door alarms, automatic-door closing devices, air locks, or other devices as approved by the District Supervisor. The rule recognizes that pressure sensors may not be the only mechanism that can be used to ensure that negative pressure is being maintained.

Comment—Several commenters recommended deleting the entire text of § 250.60(e)(3). With gas detector equipment installed at the shale shaker, this type of equipment is not necessary in the drilling fluid handling area. An alarm at the shale shaker would be the only device needed for this area.

Response—This recommendation was not adopted. The shale shaker area may not be located in the only enclosed mud-handling area. However, the proposed rule was revised to exempt open areas ventilated by natural means from the requirement for gas detectors and alarms. As a necessary corollary to a requirement for gasdetection systems, an operational test and recalibration at least once every 90 days is required in § 250.60(e)(6) of the final rule.

Comment—There were several comments submitted concerning the proposed requirements in § 250.61 to provide for securing of wells by various tools. Some of the commenters would revise the proposal to allow the use of pipe rams and an inside BOP in lieu of the use of blind-shear rams. One commenter would delete the word "timely" as unnecessary regarding the installation of well securing tools. One commenter believed the proposal is in order.

Response—The recommendation to allow the use of pipe rams and inside BOP's was adopted, given special circumstances. In floating drilling operations, the use of pipe rams and an inside preventer may be an acceptable alternate to the use of blind-shear rams to secure the well, provided there is a lack of sufficient lead time or special circumstances.

The word "timely" is meant to convey to the lessee the importance of taking full advantage of available lead time. The suggestion to delete the word "timely" from the proposed rule was not adopted.

Comment—There were several comments submitted concerning the proposed requirements in § 250.64 for lessee submittal of information regarding the maximum adverse environmental and operational conditions the rig is designed to withstand in § 250.64(b)(1) and vessel certification documentation in § 250.64(b)(2). The commenters recommended deletion of these requirements since they view them as a USCG concern. Another commenter recommended revision of § 250.64(b)(2) to delete references to U.S.-flag vessels and foreign-flag vessels.

There were numerous comments submitted concerning the proposed requirement in § 250.64(b)(3) to submit data with an APD related to design and operating limits and contingency plans to be followed, if necessary. Several commenters recommended deletion of the proposal, on the grounds that it is beyond the scope of MMS jurisdiction. Other commenters would revise the rule to require the submission of only the design and operating limits. One commenter would revise the rule to provide for the acceptance of the appropriate parts of the USCG approved MODU operating manual.

Response—Section 250.64(b)(2) of the final rule has been revised to clarify that "documentation of operational limitations" rather than "classification" is the intent. The recommendations to delete § 250.64(b) (1), (2), and (3) were not adopted, but the paragraphs were revised to make the requirements in (b)(3) applicable only to frontier areas. In frontier areas, the operational limitations under the environmental conditions anticipated for the area and rig operating manual are evaluated as part of the review and approval process of the lessee's contingency plans. The MMS does not approve MODU Operating Manuals. The MMS asks the operator to supply a copy of this manual along with information requested in § 250.64(b) which will be used for reference by MMS personnel in reviewing and evaluating the lessee's contingency plans.

The references to U.S.-flag vessels and foreign-flag vessels were deleted.

Comment—There were several comments received concerning the proposed requirement in § 250.64(b)(4) to submit a program with an APD which provides for safety in floating drilling operations, including seismic and geologic data. A few commenters recommended deletion of the proposal as unnecessary and duplicative of information contained in the shallow hazards report. Other commenters would delete the proposed seismic and geologic data, water depth, drilling fluid hydrostatic pressure, etc., in the belief

that the data have been furnished in other reports and the APD.

Response—The recommendation to delete these requirements was not adopted. The information collections suggested for deletion are considered critical to MMS's ability to assure operational safety. When information is already available in MMS files, it is only necessary for the lessee to reference the documents containing the needed information.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(e). The commenters recommended that a lessee not be required to resubmit data on a drilling unit once approval is obtained in an OCS Region, unless equipment changes are made which affect the rated capacity of the unit.

Response—These recommendations were not adopted. Each of MMS's OCS Regions represents a large geographical area with diverse local environmental and geological drilling conditions. For these reasons, each District Supervisor must retain the authority to inspect drilling units to assure that they are equipped to handle local conditions and specific circumstances. In frontier areas, rig approval may be considered on a case-by-case basis.

Comment—There was one comment submitted concerning the proposed requirement in § 250.64(f)(1) to submit a plat showing surface and subsurface locations of the proposed wellbore to be drilled and of all the wells previously drilled in the vicinity from which information is available. The commenter would delete as unnecessary the locations of all wells previously drilled in the vicinity.

Response—The recommendation was not adopted. The District Supervisor may need the required information in order to expedite the evaluation and approval of the lessee's APD.

Comment—Comments were submitted concerning the proposed requirement in § 250.64(f)(2) that lessees submit the anticipated surface pressure and calculations used to determine the anticipated surface pressure. One commenter would delete the proposal to submit the calculations as impractical. One commenter would better define "anticipated surface pressure."

Response—These recommendations were not adopted. The lessee's estimate of the anticipated surface pressure is a primary factor in design of its well casing program, BOP's, and other well-control equipment and has a bearing on well-control procedures.

Comment—One commenter believed that the referenced data records required in § 250.64(f)(2)(vii) should not be submitted unless requested on a case-by-case basis by the Regional Supervisor.

Several other commenters recommended that this paragraph be deleted since the information is already required to be submitted with the Exploration Plan.

Response—These recommendations were not adopted. Information submitted in support of the APD is applicable to a site-specific location and includes many site-specific details not submitted with an Exploration Plan. Specific information previously submitted with the Exploration Plan need not be resubmitted but should be referenced.

Comment—There were a few comments submitted concerning the proposed requirement in § 250.64(f)(3)(ii) to submit a well-control procedure if the anticipated surface pressure exceeds the annular BOP rated working pressure. The commenters recommended deletion of the proposed requirement on the grounds that the annular BOP would not be used at surface pressures exceeding the anticipated surface pressure.

Response—These recommendations were not adopted. The information required under this paragraph relates to the requirements in § 250.56(c) which may allow the rated working pressure of the annular preventer to be less than the anticipated surface pressure.

The information required in § 250.64(f)(3)(ii) of the final rule is necessary. Its purpose is to provide evidence to the District Supervisor that the lessee is prepared to use other well-control measures and procedures to assure that the installation of a lower rated annular preventer would not compromise safety.

Comment—There were numerous comments submitted concerning the proposed requirement in § 250.64(f)(3)(iv) to submit a dimensioned schematic drawing of the diverter system. The commenters recommended that the proposal require less detailed information on the grounds that such detail is unnecessary, and the relationship of the wellhead to the rig is not known until the rig is moved on location.

Response—These recommendations were adopted in part. If the diverter system dimensions "as-built" differ from those given in the APD, submittal of a Sundry Notice (Form MMS-331) is in order. The direction, length, and turns throughout the path of flow, including that through hoses, are necessary information. The rule is revised to delete the word "dimensioned" and to include valve size in the list of information needed.

The size of the valves in a diverter system and the number and radius of turns are critical factors in the diverter system's performance capabilities.

Comment—One commenter recommended deletion of the proposed requirement in § 250.64(f)(3)(v) to submit a detailed schematic of the BOP stack and recommended that a brief description be submitted instead.

Response—The recommendation was not adopted. The BOP stack components, arrangement, and bore sizes are essential information about vital well-control equipment.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(f)(4)(ii) to submit assumptions made to determine casing design values. The commenters recommended the deletion of this requirement as burdensome and beyond MMS scope of jurisdiction. They would revise the rule to require the submission of design factors only.

Response—These recommendations were not adopted. Calculations are no better than their underlying assumptions. Therefore, the assumptions are necessary for proper evaluation by MMS personnel.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(f)(5)(i) and (ii) to submit the drilling prognosis, including plans for coring and logging. The commenters recommended revision of the rule to require submittal of "projected plans" for coring and logging as those plans may change as the drilling operations progress.

Response—The provision has been modified to require projected plans for coring and logging. It is understood that coring and logging plans given in support of the APD are informational. But, it is important and useful information. The use of the term "prognosis" was intended to recognize that plans were subject to change.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(f)(5)(iv) to submit estimated depths at which encounters with water, oil, or gas are expected. The commenters would delete this proposed requirement as having no significance.

Response—The recommendation was not adopted, however, § 250.64(f)(5)(iv) in the final rule was revised to recognize the need for such information.

The estimated depths of hydrocarbon occurrences are useful in following the progress of a well, anticipating possible problem zones, and for resource evaluation. Estimated depth of hydrocarbon zones are used in some

instances for seasonal drilling restrictions.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(f) (6), (7), and (8) to submit details of the cementing program, mud program, and directional drilling program, respectively. The commenters recommended deletion of these requirements on the grounds that the accuracy of detailed information may change as the well progresses; therefore, the requirement would cause unnecessary paperwork.

Response—The recommendations were not adopted. It is understood that certain aspects of the programs are, by their nature, projections. The program plan is needed for an informed and proper review of the proposed drilling program. The type of cement to be used is pertinent information for this review.

Certain aspects of the mud program including the minimum quantities of mud and mud materials to be kept onsite are needed as part of a contingency plan. In some cases, there are stipulations for discharges and disposal of the mud materials that may be relevant and which are necessary to address in the mud program. When the mud program described in the APD is deficient, there is sufficient cause for not approving the APD.

Directional survey programs provide important and indispensable information for the District Supervisor to use to evaluate concerns such as the potential for encroachment of lease boundaries, for unnecessary penetration of problem zones, for locating the drill site, and of the course and targets for possible relief wells. Lessees routinely prepare directional drilling programs in their own self-interest. The burden imposed by requiring submittal of copies of the program is therefore minimal.

Comment—There were several comments submitted concerning the proposed requirement in § 250.64(f)(11) to submit other information as may be required by the District Supervisor. The commenters recommended the deletion of this requirement on the basis that individual Supervisor's prerogatives would create inconsistency in submittal requirements.

Response—The recommendation was not adopted. The MMS recognizes the need to avoid disparities in interpretation and nonuniform enforcement measures. However, the unique nature of drilling operations requires that the District Supervisor exercise a degree of independence when considering site specific conditions during their review and approval of drilling plans and the revision of such plans.

Comment—There were a few comments submitted concerning the proposed requirements in § 250.65 for submittal of Form MMS–331, Sundry Notices and Reports on Wells.

One commenter recommended that the coastal State affected receive a copy of the proposed change in plans from the lessee or MMS. One commenter stated that Form MMS–330, Well (Re)Completion Report and Log, would satisfy the proposed requirement for completed or recompleted wells.

Response—This recommendation was not adopted. The lessee's plan (EP and DPP) and major revisions of approved plans are sent to the coastal State(s) for review and consultation or coastal consistency as appropriate. The Form MMS–331, Sundry Notices and Reports on Wells, is used for a variety of requests for approval or subsequent reports of performing certain operations pursuant to an approved EP or DPP. The MMS has revised reporting Forms MMS–330, MMS–331, MMS–331C, and MMS–332 to improve clarity in the information being sought and to minimize duplicative and overlapping information collections.

Comment—Several comments were submitted concerning the proposed requirement in § 250.65(c) to submit a certified plat regarding the final surveyed well location, water depth, and rotary kelly bushing elevation once they have been determined. The commenters recommended clarification of the term "certified plat."

Response—Section 250.65(c) of the final rule has been revised to provide for the submission of a plat certified by a registered land surveyor.

Comment—One commenter recommended that a provision should be added to § 250.66 that specifically sets the record retention period. Storage problems could result from indefinite retention periods.

Response—This recommendation has been adopted. The first sentence in § 250.66(a) of the final rule has been revised by inserting the words "for a period of 2 years" between the word "keep" and before the word "at."

Comment—There were several comments submitted concerning the proposed requirement in § 250.66 for the lessee to keep well records at the field office nearest the OCS facility or other locations conveniently available to the District Supervisor. The commenters recommended that the proposed rule be revised to allow the lessee complete discretion as to where operating records are kept, as long as they are available and can be inspected by MMS personnel during normal business hours. One commenter would delete the proposal regarding other information required by the District Supervisor.

Response—These recommendations were not adopted. Records of operations kept at a location which is far from the District and the operations to which the records apply would adversely affect the ability of the operator's personnel and MMS's District Supervisor to carrying out their responsibilities. Recordkeeping at field offices is allowed as an alternative to lessees being required to maintain a set of records on each offshore facility.

Comment—There were several comments submitted concerning the proposed requirement in § 250.66(b) for the lessee to transmit duplicate copies to the District Supervisor of the records of all activities related to and conducted during the suspension or temporary prohibition of drilling operations or attached to Form MMS–330 or MMS–331. The commenter recommended that this proposed rule be clarified to ensure consistency in submittal.

Response—The recommendation was adopted. The information referred to is that which pertains to activities conducted under a suspension of operations as described in § 250.10. To make this clear, § 250.66(b) of the final rule has been revised by inserting the phrase "under the provisions of 30 CFR 250.10, Suspension of production and other operations," between the words "prohibited" and "the lessee."

Comment—There were a number of comments submitted concerning the proposed requirement at § 250.66(c)(3) to furnish copies of the daily drilling report showing location, description, and status of all wells on leased land upon request by the Regional or District Supervisor. The commenters recommended that the proposed rule be revised to provide the daily drilling report only, and exclude the requirement for status of all wells on the lease, as the daily drilling report does not show this.

Response—This recommendation was adopted and § 250.66(c)(3) of the final rule has been revised accordingly. The location, description, and status of all wells on leased lands other than drilling wells are available to the District Supervisor from other documents and sources.

Comment—There were numerous comments submitted concerning the proposed requirement at § 250.66(c)(4) to furnish copies of service company reports on cementing, perforating, acidizing, analyses of cores, testing, or other similar services. The commenters recommended that the proposed rule be

revised to provide that lessee reports be furnished rather than copies of the service company reports on the grounds that service company reports may be inexact, limited, or unavailable, and the requirement consequently would be burdensome.

Response—This recommendation was not adopted. Service company reports are especially important documentation regarding operations that are not witnessed by MMS personnel. The information contained in those documents is also useful for verifying and interpreting other data submitted by the operator.

Comment—There were several comments submitted concerning the proposed requirement at § 250.66(d) to transmit, as soon as available, copies of logs or charts of electrical, radioactive, sonic and other well-logging operations, directional-well surveys, and analysis of cores. Also, composites of multiple runs and directional-well surveys are required to be transmitted to the District Supervisor as soon as available but not later than 30 days after completion of such operations for each well. The commenters recommended that the requirement be revised to provide for the submittal of the listed material as soon as available and composites within 30 days after completion of operations on the well. The proposal, as written, is considered by the commenter to be redundant, and the commenter's proposed revision is considered to be consistent with other required submittals of information. One commenter pointed out that this information is required in § 250.66(a) and is required to be submitted upon request in § 250.66(c) (1) and (4). The first sentence of § 250.66(d) is presently in effect, and the information is required within 30 days after well-completion. One commenter suggested that MMS bear the cost of additional copies.

Response—Minor changes were made in § 250.66(d) of the final rule. The intent of the rule is that composite logs be submitted as soon as available but not later than 30 days after completion of the well. The words "such operations for" have been deleted from the last sentence to clarify the intent. Minor elements of apparent redundancy among the paragraphs of § 250.66 are present for the sake of added clarity.

Comment—There was one comment concerning the proposed requirement at § 250.66(f) for the lessee to submit any other reports and records of operation requested by the District Supervisor.

The commenter recommended that this part of the proposed rule be deleted on the grounds that the requirement is too broad or arbitary, and the lessee should know specific requirements "up front."

Response—This recommendation was not adopted. The unique nature of each drilling and production operation makes it important that lessees and MMS recognize its authority and responsibility to require a lessee to provide any and all the information needed to assure that the lessee's proposed activity can be conducted safely.

Comment—Several commenters recommended deleting the word "all" between the words "take" and "necessary" from § 250.67(a)(1) on the grounds that the use of the inclusive term "all necessary precautions" places the lessee in an untenable liability position in the event an H_2S incident occurs.

Response—This recommendation was not adopted. The purpose of § 250.67(a)(1) is similar to that of § 250.50 in that it is intended to provide direction and to state goals. In order to reduce any problems in interpretation that the word "all" may cause, § 250.67(a)(1) of the final rule has been revised by adding the words "and practicable" between the words "necessary" and "precautions."

Comment—A commenter recommended the word "unknown" be changed to "suspected" for clarification of the intent of § 250.67(a)(2).

Response—This recommendation was not adopted. Section 250.67(b)(3) outlines the meaning of "zones where the presence of H_2S is unknown."

Comment—One commenter, referring to the definition of the word "facility" in § 250.67(b), contended that since satellite-well protection structures utilized by it do not meet the criteria that would cause them to be defined as a production facility, those satellite structures should not be subjected to the requirements for the installation of H_2S protection, warning devices, and safety equipment specified under the proposed rules. The commenter argued that since these satellite structures do not hold pressurized vessels or any other type of equipment for the separation, processing, or transport of produced liquids or gas, they should be exempt from the current definition of a "facility" and be addressed separately as to the requirements for H_2S detection, monitoring, and protective-breathing equipment.

One commenter recommended changing the criteria of H_2S atmospheric concentration from 20 ppm to 50 ppm contending this is an acceptable concentration for the protection of health for an 8-hour day, 5-day week.

A few commenters contended that the proposed definitions for "zones known to contain H_2S" and "zones where the presence of H_2S is unknown" assume that the technology used in forecasting the actual conditions is based on highly reliable methods of determining zone classification. These forecasts rely on data validity, personnel experience, and some judgment which must be applied. The commenter recommended that these definitions be revised to reflect that forecasts are made using the best available data and judgments.

One commenter stated that the definition of "zones where the absence of H_2S has been confirmed" needs further classification. A strict interpretation of the proposed regulations would require use of all H_2S precautionary measures for all wildcats. An alternative might be to require H_2S detection and monitoring equipment only for wildcat wells or zones where the presence of H_2S requirements down to a specific geologic area, such as Miocene, where H_2S has historically not been encountered throughout OCS waters, specifically in the GOM Region.

Several commenters referring to § 250.67(b)(3) recommended substituting the phrase "continuous and homogeneous bedding exists" with the phrase "equivalent stratigraphic units" on the grounds that continuous and homogeneous bedding is often totally undefinable over short geographic distances, therefore, proof of that continuity may rarely be possible. Geologic units, on the other hand, are often correlative over much greater distances.

Response—These recommendations have not been adopted other than to modify § 250.67(b)(3). Section 250.67(b)(3) of the final rule has been revised by replacing the words "continuously and homogeneous bedding exists" with "equivalent stratigraphic units exist." It is recognized that faults, salt domes, and other breaks in continuity can prevent correlation of geologic and seismic data to show an absence of H_2S.

Satellite well-protection structures meet the essential criteria to be defined as production facilities. However, there may be situations where some of the requirements concerning H_2S protection and warning devices may not be necessary. Satellite structures can be treated as special cases, and according to § 250.3, the lessee may request and the District Supervisor may grant departures from some of the operational requirements.

Recommended practices developed by the oil industry consider 20 ppm as an

acceptable concentration for 8 hours of exposure. Those recommended practices do not include 50 ppm as being an acceptable exposure level for 8 hours. Current Occupational Safety and Health Administration Permissible Exposure Limit for H_2S is a 20-ppm ceiling or 50-ppm peak exposure for 10 minutes in an 8-hour shift only if no other measurable exposure occurs.

The final rule is designed to protect human health and life by requiring the use of H_2S precautionary measures for proposed drilling in "zones where the presence of H_2S is unknown."

Comment—In § 250.67(c), one commenter recommended revising the first sentence to read:

> Based on data furnished by the District Supervisor, operations will be classified as those in an area that is known to contain H_2S, where the presence of H_2S is unknown, or where the absence of H_2S has been confirmed. Should there be disagreement with the data furnished by the District Supervisor, a classification of operations can be made supported by applicable information such as geologic and geophysical data and correlations, well logs, formation tests, cores, and analyses of formation fluids on a case-by-case basis.

The commenter contended that it would be an undue burden on the operator and lead to the creation of massive paperwork to request a classification from the District Supervisor prior to any operation. The MMS should provide a master list classifying each geologic formation and areas as containing H_2S, as not containing H_2S, or the presence of H_2S is unknown. Then, if an operator has data that are in conflict with this master list, the operator can present that data on a case-by-case basis.

Several commenters recommended that MMS's approval of the "request for classification of probability of encountering hydrogen sulfide" be based on revised zone definitions as discussed in comments submitted under § 250.67(b).

One commenter recommended changing the word "unknown" to "suspected" concerning H_2S zones.

Response—These recommendations have not been adopted; however, § 250.67(c) of the final rule has been modified by the addition of a sentence which reads:

> The classification shall be updated when additional data indicate there is cause for a change in an approved classification.

It is the lessee's responsibility to demonstrate that its proposed drilling activity can be conducted in a safe and environmentally acceptable manner.

It is unfortunate that, except in a few localized areas, no organized body of geologic and drilling information base exists on which MMS can make advance categorizations of the probability that H_2S will be encountered. Thus, forecasts must be made using the best available data and judgments.

The recommendation to change the word "unknown" to "suspected" has not been adopted. The H_2S incidents could very well occur in zones where the presence of H_2S is "unsuspected." Requirements in zones where the presence of H_2S is only "suspected" is insufficient as well as vague.

Commenters are referred to §§ 250.33(a)(9) and 250.34(a)(6) which require lessees to request the Regional Supervisor's approval of a classification in connection with the approval of EP's and DPP's.

Comment—Several commenters recommended adding a sentence at the end of § 250.67(d) to read:

> These requirements shall be implemented at least 1,000 feet prior to entering any zone known to contain H_2S.

The commenters contended that since H_2S containing zones may be deeply buried and require months of drilling operations before it becomes necessary to prepare the rig and crew for H_2S operations, expenses for installation and maintenance of equipment and training personnel for long periods of time prior to the point of need are not reasonable or justifiable.

Several commenters recommended implementing the requirements of § 250.67(e) 1,000 feet before entering a zone where the presence of H_2S is unknown.

Response—This recommendation has not been adopted. The proposed criteria of 1,000 feet prior to entering an H_2S zone or encountering a zone where the presence of H_2S is unknown is too arbitrary for general application, may not provide sufficient time for preparation, and assumes that the depths of such zones are accurately known. A shut-down of drilling operations while preparations are completed could be more expensive than preparing equipment and personnel earlier. The intent of the rule is that the lessee be fully prepared to cope with H_2S before drilling into an H_2S bearing zone and while that zone is open to the wellbore. The lessee's proposed H_2S Contingency Plan is the best means of addressing the particular circumstances.

Comment—A commenter recommended deleting the words "approval" from the first sentence of § 250.67(h)(1) and "approved" in the second sentence on the grounds that the approval process could interfere with the proposed timing of an operation. A plan should be on file but not necessarily approved.

Response—This recommendation has not been adopted. The planned operations along with the H_2S Contingency Plan must be approved by the authorized MMS official prior to start of operations.

Comment—A commenter recommended that under § 250.67(h)(1)(ii), the job position responsible for the overall safety of the personnel should be a part of the platform owner/operator's organization and not part of the lessee's organization.

Response—The responsibility for any and all activities on a lease ultimately rests with the lessee. Although the operator of a platform may not be a part of a lessee's organization, the lessee remains responsible for the actions of the platform operator.

Comment—In § 250.67(h)(1)(iii), one commenter recommended changing the word "air" to "atmosphere." Another commenter recommended deleting the 10-ppm concentration level cited in (A), claiming that the relatively high incidence of false alarms inherent with the use of a 10-ppm sensor will lead to a undesirable degree of complacency.

Another commenter contended that it is important that the presence of the three distinct levels in § 250.67(h)(1)(iii) be indicated through the visual and audible alarms discussed in § 250.67(h)(3), (4), and (5) and suggested that these paragraphs be changed to better support the intent of § 250.67(h)(1)(iii).

Response—The recommendation to change the word "air" to "atmosphere" was adopted. The recommended modification to § 250.67(h)(1)(iii) was not adopted.

The 10-ppm concentration level requirement in 250.67(h)(1)(iii)(A) remains. According to § 250.67(h)(5)(i), the H_2S detection and monitoring system activates audible and visible alarms when the concentration of H_2S exceeds 20 ppm. Sensors are available which perform at 10 ppm without nuisance signals, provided they are appropriately protected and maintained.

Section 250.67(h)(3) of the final rule has been revised to require that a visual alarm be activated by detection equipment at 20 ppm. Section 250.67(h)(4) of the final rule has been revised to require that an audible alarm be activated by detection equipment at 20 ppm, and § 250.67(h)(5) of the final rule has been revised to clarify that the detection system be capable of accurately sensing a minimum

concentration of 10 ppm of H_2S in the atmosphere.

Comment—A commenter recommended deleting the last two sentences from § 250.67(h)(1)(iv) concerning briefing areas on the grounds that the requirement is too specific and that any prudent operator will have safe briefing areas in its plan.

Response—This recommendation was not adopted. The specification for two briefing areas actually clarifies and defines the minimum number required.

Comment—Two commenters recommended revising § 250.67(h)(2) to say that the requirements would be implemented 1,000 feet prior to entering any zone known or suspected to contain H_2S that would produce a concentration of 20 ppm in the ambient work atmosphere. One of the commenters also suggested that training of crews weeks before penetrating an H_2S zone could result in the personnel becoming complacent.

Response—The recommendation has not been adopted. Waiting to implement the onsite safety training program 1,000 feet prior to encountering a zone which contains H_2S is arbitrary and not practicable as a rule. Drilling rates may be in excess of 2,000 feet per day and the depth of the zone may not be known with accuracy. Required preparation must be accomplished well in advance of the actual drilling of H_2S bearing formations. It is intended in § 250.67(h)(2) of the final rule that training be initiated, completed, and reviewed as appropriate before a H_2S bearing zone is encountered.

Comment—One commenter recommended deleting the phrase "H_2S detectors and" from § 250.67(h)(2)(iii) on the grounds that the location of detectors is not relevant to all personnel, e.g., the cook does not need to know an H_2S detector is located on the bell nipple.

Response—This recommendation was not adopted. All personnel should be as knowledgeable as reasonably possible about the location of H_2S detectors and the steps and protective measures to be initiated when an alarm is sounded.

Comment—In § 250.67(h)(2)(vi), several commenters recommended replacing the phrase "prior to beginning operations" with the phrase "within 24 hours after duty begins" contending that the MMS requirement, as proposed, is onerous.

One commenter recommended deleting the phrase "and training session" claiming it to be redundant with § 250.67(h)(2) (i), (ii), (iii), and (iv). This commenter recommended replacing the phrase "each crew prior to beginning operations" with the phrase "all personnel at the facility" contending that a drill should include everyone on board and not just the crew.

One commenter recommended changing § 250.67(h)(2)(vi) to require weekly training sessions for drilling or workover operations and monthly sessions for production operations contending that since contract people are coming and going frequently during drilling and workover operations, drills and training sessions on a weekly basis would be necessary. However, since production operations are conducted at a more moderate pace, monthly sessions would be more appropriate inasmuch as personnel on the facility are well trained, and the risk of an H_2S release is less than during drilling operations.

Another commenter claims that the requirement to conduct a drill and training session once every 7 days for each crew is excessive.

Response—The recommendation was adopted to allow the conduct of a drill for each crew member within 24 hours after their duty begins. The recommendation that a training session be conducted within 24 hours was not adopted. With contract and other personnel coming and going frequently, training for all personnel upon arrival is considered vital. Problems with H_2S may arise at any time.

The recommendation that drills include all personnel on the facilities was adopted.

The recommendation that drill and training sessions for drilling and workover operations be conducted more frequently or at different intervals than those for production operations has not been adopted.

Comment—In § 250.67(h)(3), a commenter pointed out that there is no mention of visual indicators (i.e., flashing lights) to be activated by the H_2S monitoring system as required in § 250.67(h)(5).

Response—The comment has been duly noted, and § 250.67(h)(3) of the final rule has been revised to include a requirement for a visual alarm.

A new § 250.67(h)(3)(ii)(E) is added to make clear that production facilities with wells capable of producing H_2S be marked with warning signs under nonemergency as well as emergency conditions.

Comment—In § 250.67(h)(4), several commenters contended that there is no reason to install explosion-proof warning devices in an unclassified location where they would be surrounded by other nonexplosion-proof electrical equipment. Only warning devices installed in classified locations, as defined in 46 CFR 108.70 through 108.77, should be required to be explosion-proof.

One commenter recommended that the warning devices required in the paragraph have a unique sound used only for H_2S warning; otherwise, the same device would be used for a production alarm and for H_2S warning which would be confusing.

One commenter recommended that it be made clear that the audible devices and paging systems are intended to complement, not reduce or eliminate the need for the visual warning devices.

Response—The recommendations have been adopted, and § 250.67(h)(4) of the final rule has been modified to incorporate the suggestions.

Comment—One commenter recommended adding the phrase "including various sensor locations for production platforms" to the last sentence in § 250.67(h)(5)(i) on the grounds that, for safety reasons, production platforms as well as drilling rigs should be equipped with H_2S sensors.

One commenter recommended inserting the phrase "as appropriate" after the phrase "poorly ventilated" contending that production or workover/completion operations will not have some of these areas. The sensing points specified apply to drilling operations only.

Several commenters recommended deleting the phrase "in hazardous quantities" in § 250.67(h)(5)(i) contending that this improves clarity and is consistent with the phrase "may accumulate" in § 250.67(h)(8).

One commenter recommends that H_2S detection and monitoring equipment should be provided on mobile drilling rigs at all times contending that the cost to install the equipment is minimal.

Response—These recommendations have been adopted with the exception of the one relating to mobile drilling rigs. The phrase "as appropriate" has been added and the phrase "in hazardous quantities" deleted from § 250.67(h)(5)(i) in the final rule.

The H_2S detection and monitoring equipment need not be provided on mobile drilling rigs where the absence of H_2S has been confirmed.

Comment—In § 250.67(h)(5)(ii), several commenters contended that it is unnecessary and counterproductive to calibrate detection and monitoring equipment every 8 hours or even every day.

One commenter contended that the majority of available equipment is capable of staying in calibration for over a week but most only recommended calibration every 2 weeks. This time

span could be shortened if it is found that the instruments are substantially out of calibration each week.

A few commenters recommended changing the calibration frequency for drilling and production to "monthly with an operational check" contending that the calibration frequencies specified are totally unjustified and could lead to a reduction in safety because some sensors reduce their sensitivity to H_2S each time they are exposed to it. Some manufacturers of detectors recommend a calibration schedule of 30 to 90 days depending on the installation.

Several commenters recommended initial calibration with daily functional checks and weekly field calibrations thereafter contending that it can take up to 3 hours to calibrate all equipment. This would require additional personnel to run calibrations.

Several commenters recommended changing the wording in the first two sentences to read:

> The H_2S detection and H_2S monitoring equipment shall be initially field calibrated when drilling approaches a potential H_2S bearing zone and functionally tested at least once daily with weekly field calibrations when drilling, well completion, and/or well workover operations are being conducted in an H_2S environment. The H_2S detectors for production operations shall be field calibrated at least weekly.

The commenters contended that MMS's requirements for sustained equipment calibration once every 8 hours can render the sensors inoperative by burning them up. Calibration of the equipment every 8 hours will require two full-time people to test and service the equipment with little or no increase in safety or equipment reliability.

Another commenter recommended that the calibration frequency be curtailed to once every 12 hours when drilling, completion, and/or workover operations are being conducted in an H_2S environment. This is more than adequate for most systems available and suits the work shifts involved.

Response—After careful consideration of these recommendations, § 250.67(h)(5)(ii) of the final rule has been revised to require a calibration frequency of 24 hours when approaching an H_2S bearing horizon or drilling a horizon whose H_2S content is unknown; 12 hours when drilling, well-completion, and well-workover operations are being conducted in an H_2S environment; and at least once every 7 days during production operations. Manufacturers' recommendations concerning calibration frequency vary widely. The range is from once each week to once every 3 months. However, technology has not advanced to the point where the performance of H_2S sensors is predictable enough for reliability. The environment in which the device is placed is a major factor. Therefore, frequent calibration of these devices must be required to assure safety of operations.

Comment—In § 250.67(h)(5)(iii), several commenters recommended changing the second sentence to read:

> After H_2S has been initially detected, poorly ventilated areas not equipped with fixed H_2S detection equipment shall be evaluated, utilizing a portable H_2S detection instrument.

The commenters contended that areas with fixed detection equipment do not need to be checked with portable equipment.

One commenter recommended inserting the phrase "concentration of 20 ppm" after H_2S in the second sentence to define inspection frequencies. The commenter contended that smaller concentrations of H_2S are not harmful.

Response—The recommendation to permit the use of portable equipment to test poorly ventilated areas not equipped with fixed H_2S detection equipment has been adopted, and § 250.67(h)(5)(iii) of the final rule has been revised accordingly.

The recommendation to insert the phrase "concentration of 20 ppm" in the second sentence of § 250.67(h)(5)(iii) has not been adopted. The addition of that phrase could mislead personnel into assuming that a lower concentration would be acceptable and frequent inspections unnecessary. Concentrations of H_2S increase by accumulation of gases in low-lying and unventilated areas.

Comment—In § 250.67(h)(6), one commenter suggested that consideration should be given to installing an H_2S detection/monitoring system equipped with visual and audible alarms on all workboats attendant to facilities operating in known or unknown H_2S environments.

Response—This recommendation has been adopted. The proposed rules failed to include adequate safety measures for the protection of crews on standby vessels, crew boats, and workboats and for the safe evacuation of personnel from a facility. Therefore, § 250.67(h)(1)(v) and 250.67(h)(6)(iv) of the final rule have been revised to provide that protection.

Comment—In § 250.67(h)(6)(i), (iv) and (v), several commenters recommended deleting the phrase "and/or SO_2" in those paragraphs contending that sulphur dioxide (SO_2) results from burning H_2S and that normally SO_2 zones do not exist. Therefore, the phrase would be unnecessary.

Response—This recommendation has been adopted, and the phrase "and/or SO_2" has been deleted from § 250.67(h)(6)(i), (iv), and (v) of the final rule.

Comment—Several commenters recommended deleting § 250.67(h)(6)(ii) because it deals with the storage location of protective-breathing apparatus that is sufficiently addressed in § 250.67(h)(6)(i) where it is required that personnel have immediate access to protective-breathing apparatus.

Response—This recommendation was not adopted. In order for personnel to have immediate access to respirators, the storage location must be easily accessible.

Comment—In § 250.67(h)(6)(iv), several commenters recommended the deletion of the second sentence which states:

> When 20 ppm or more of H_2S is detected, workboats shall be notified to move upwind and stay under power until the H_2S is brought under control at the source.

The commenters contended that requirements/actions to be performed by workboats during emergency releases should be defined in the H_2S Contingency Plan and are specific to the installation and hazards.

Response—This recommendation has been adopted. The second sentence in § 250.67(h)(6)(iv) has been deleted from the final rule. In order to make the requirement less restrictive, the words "pressure-demand type respirator" have been replaced with the words "appropriate protective-breathing equipment."

Comment—In § 250.67(h)(6)(v), a commenter recommended the use of the phrase "flight crews" in lieu of the words "pilots" and "pilots and co-pilots" contending that the language would provide for the safety of personnel who are not pilots or copilots but may be assigned to the helicopters.

Several commenters recommended that the paragraph be revised to include the phrase "immediately accessible to the heliport for the use of flight crews," contending that the phrase would provide for clearer language.

One commenter suggested deleting the last sentence in the paragraph contending that there are numerous different types of respirator equipment and there would not be a way to ensure that pilots and copilots are trained to operate and use the equipment placed on a facility for them.

Response—The recommendations to substitute the phrase "flight crew" for

"pilots" and "pilots and co-pilots" have been adopted. The recommendation to delete the last sentence of § 250.67(h)(6) was not adopted.

Section 250.67(h)(6) of the final rule requires that all flight crew members be trained in the use of the particular type(s) of respirator equipment made available for them.

Comment—In § 250.67(h)(7)(iii), several commenters recommended substituting the phrase "chalkboards and note pads" with the phrase "chalkboards and/or note pads" contending the language provides flexibility and clarity for the use of that equipment at various locations under different climatic conditions.

Response—This recommendation has been adopted.

Comment—In § 250.67(h)(9), several commenters recommended that the provision be revised to account for incidents of short-term releases of H_2S (e.g., sampling, purging, etc.) that can result in a short duration atmospheric concentration in excess of 50 ppm but do not dictate initiation of emergency procedures and regulatory agency notifications.

Response—This recommendation has been adopted.

Comment—In § 250.67(i)(2), one commenter recommended deleting the entire provision contending that the Garrett-Gas-Train Test and other analysis techniques for soluble sulfides simply measure the quantity of soluble sulfides present in the fluid and that there is not a direct correlation between a soluble sulfides measurement and ambient H_2S measurements.

One commenter recommended that in the first sentence of the subparagraph the phrase "and the results * * * the other sensors." be replaced with the phrase "to confirm the presence of H_2S, if the concentration of H_2S detected by air sensors is in excess of 20 ppm" contending that measurements of soluble sulfides are meaningless once H_2S has broken out and is detectable on the surface and that the Garrett-Gas-Train analysis detects soluble sulfides and not H_2S.

Response—The substitution of "to confirm * * * in excess of 20 ppm" for "and the results * * * the other sensors" has been adopted. The recommendation that § 250.67(i)(2) be deleted has not been adopted. Detection of H_2S in the mud system is a key defense against exposure since the toxic gas must enter the mud systems before it can be released at the surface. The Garrett-Gas-Train method is one of several detection methods that may be used to confirm and quantify the amount of soluble sulfides in the mud.

Comment—In § 250.67(i)(3)(i), one commenter recommended revising the provision to read: "When drilling within 100 feet of a known H_2S-bearing zone, drilling fluid additives, such as lime and caustic soda for control of H_2S, shall be available at the facility. When H_2S has been detected, the additives should be added as needed," contending that caustic soda and lime have proven effective in mud systems without the use of any so-called scavengers.

One commenter recommended revising the provision to read: "When H_2S is detected, scavengers for the control of H_2S may be added to the oil or water base mud system," contending that the use of scavengers should not be mandatory.

Several commenters recommended that the phrase "added to * * * mud systems" in the first sentence of the provision be replaced with the phrase "available on the facility. When H_2S has been detected, scavengers shall be added to the drilling fluid only after H_2S is detected" contending that arbitrary addition of a scavenger before H_2S is detected could mask the detection of sulfides in the drilling fluid.

Response—These recommendations have been adopted, and § 250.67(i)(3)(i) of the final rule has been revised accordingly.

Comment—In § 250.67(i)(3)(ii), one commenter recommended deleting the entire paragraph contending that control of pH should be dependent on exact mud type, and an arbitrary pH level of 10 is not recommended for some mud types.

One commenter recommended revising the paragraph to read: "Additives for the control of fluid density and pH should be added to the water-base control fluids to eliminate the influx of fluids containing H_2S and maintain a pH of at least 10," contending that controlling the influx of H_2S by increasing the mud weight is the most effective program when dealing with H_2S.

Response—These recommendations were not adopted. Maintaining a high pH is an effective way to control H_2S, and muds that are compatible with a pH of 10 are available. It is unnecessary to include in the rule that adding weighting materials to the mud system is an effective control against influx.

Comment—In § 250.67(i)(4), several commenters recommended revising the second sentence in the provision to read, "The gases so removed shall be collected and vented to the atmosphere in a well-ventilated location away from personnel."

One commenter contended that the requirement for a closed flare system with pilots and automatic igniter in operation during essentially all operations is not reasonable. A closed flare system is not needed until the operator approaches a suspected H_2S-bearing zone. One commenter agreed that gases containing H_2S should not merely be "vented" in a well-ventilated location, away from personnel, but should also be burned.

Response—The recommendation to revise the rule to allow direct venting without burning the gases has not been adopted. The intent of the rule is that H_2S gas be fully contained until exhausted at the flare outlet where it is to be burned. Approval for direct venting, if justified, can be handled on a case-by-case basis. Degassing is not required until the well-control fluids contain H_2S.

Comment—In § 250.67(k)(1), one commenter recommended changing "an H_2S zone" in the paragraph heading to "a zone known to contain H_2S" for consistency in the rule. The rewording would make tests that are performed in a zone where the H_2S concentration is 50 ppm comply with the mandate of the rule.

Several commenters recommended deleting the words "competent" and "knowledgeable" from the last sentence in the paragraph contending that competence and knowledge implies the lessee can guarantee personnel whose response to training results in adequate performance on the job. Personnel can be trained, but competence and knowledge can only be assumed.

Response—The recommendation to revise the heading to "Well testing a zone known to contain H_2S" has been adopted as being consistent with § 250.67(b) where such a zone is defined.

The recommendation to delete the words "competent" and "knowledgeable" from the last sentence of § 250.67(k)(1) of the final rule has not been adopted. Competence and knowledge can be ascertained, and incompetent or inexperienced personnel should not be employed in the hazardous well testing of zones known to contain H_2S.

Comment—In § 250.67(k)(5), one commenter recommended replacing the word "tubing" with the word "tubulars" in the first sentence contending that the terms "tubing" and "drill pipe" are not defined. Tubulars encompasses tubing, drill pipe, and casing.

One commenter recommended replacing the words "treated fluid" with the words "fluid treated" in the last sentence for clarity.

Several commenters recommended the deletion of the second sentence

contending there is no technical reason not to use drill pipe in testing oil wells containing H_2S. This has been common practice in the past and should be continued subject to the provisions contained in API RP 49, draft 2nd edition. There are many instances, such as in low-pressure wells, where certain types of drill pipe are perfectly safe.

Response—The recommendations have been adopted to replace "tubing" with "tubulars" in the first sentence and "treated fluid" with "fluid treated" in the last sentence of § 250.67(k)(5) of the final rule.

The recommendation to delete the second sentence from § 250.67(h)(5) was not adopted. The District Supervisor can approve the use of drill pipe for H_2S oil-well testing as an alternate methodology under § 250.3 when that action is justified.

Comment—In § 250.67(l)(1), one commenter recommended replacing the phrases "H_2S zone" in the heading and "H_2S environments" in the first sentence of the provision with the phrase "a zone known to contain H_2S" for consistency in the rule and because the meaning of the words H_2S environments has not been defined.

Another commenter recommended adding a new sentence to read: "New technology may be used with the approval of the District Supervisor." This would increase flexibility for the use of new standards as they develop.

Response—The recommendation to replace the phrase "an H_2S zone" in the heading with the phrase "zones known to contain H_2S" has been adopted. The revised heading is consistent with § 250.67(d) that requires operations in accordance with § 250.67(l)(1) in zones known to contain H_2S.

The recommendation to add a new sentence specifically allowing the use of new technology upon approval by the District Supervisor has not been adopted. Section 250.3 permits this action so there is no need to include similar provisions in § 250.67 of the final rule.

Comment—In § 250.67(l)(2), several commenters recommended revising the heading and the paragraph to add drill pipe to the tubular goods to be designed according to NACE MR-01-75 requirements for use in H_2S environments.

Response—The recommendation has been adopted.

Comment—In § 250.67(l)(3), several commenters recommended the paragraph be revised to exclude bolts, nuts, and fittings not subjected to exposure to H_2S from the requirement to conform to NACE standard MR-01-75 contending that this is an unnecessary requirement for those components that can only be exposed to H_2S bearing fluids at atmospheric pressure in the event of a leak or component failure.

Response—This recommendation was adopted.

Comment—In § 250.67(l)(6), several commenters recommended adding the following sentence to the end of the paragraph "Welding and burning operations should comply with § 250.52" contending that this addition will provide more complete guidance to the lessee.

Response—This recommendation was not adopted. Compliance with NACE MR-01-75 is specified in the paragraph. Section 250.52 addresses safety precautions only in welding and burning operations and is not a useful reference in § 250.67(l)(6) of the final rule.

Comment—In § 250.67(m)(2), one commenter recommended adding the word "conventional" before the phrase "coring operations" contending that the requirements of the paragraph do not apply to sidewall coring.

Response—This recommendation has been adopted.

Comment—In § 250.67(m)(4), one commenter recommended adding the phrase "or if the well is under pressure" at the end of the paragraph contending that stripping operations are normally performed to remove tubing utilized to initiate flow. If the well does flow or exhibit pressure, the potential for H_2S being released is increased in the areas of the stripping rubbers.

Response—This recommendation has been adopted.

Comment—In § 250.67(m)(6), one commenter recommended deleting the last two sentences of the paragraph contending that they are redundant since high stresses mentioned in the third sentence are the result of the conditions listed in the last two paragraphs.

Several commenters recommended revising the third sentence by replacing the word "employed" with the word "taken" stating that the proposed revision would provide consistency with the sentence that follows.

Response—The recommendation to delete the last two sentences of § 250.67(m)(6) has not been adopted. The items listed in those sentences recite some of the conditions that expose drill strings to high stresses. The purpose of the partial list is to provide clarity.

The recommendation to replace the word "employed" with the word "taken" has been adopted. This change provides continuity with the subsequent sentence.

Comment—In § 250.67(m)(7), several commenters recommended changing the phrase "flare lines" in the second sentence with the phrase "flare line outlets" contending that the location or path of the flare line will be dictated by the design of the facility and will undoubtedly be away from critical areas.

One commenter recommended replacing the phrase "flare lines" with the phrase "the flare line used" contending that multiple flare lines will likely exist.

Several commenters recommended rewording the fourth sentence to read: "Alternate methods for igniting the flare shall be available" contending that the method(s) of flare ignition should be left to the discretion of the operator.

Response—These recommendations have been adopted.

Comment—In § 250.67(m)(10), several commenters recommended revising the paragraph to read: "The H_2S content in the fuel and/or instrument gas should not exceed 50 ppm" contending that the cost of a gas-sweetening system for fuel to fire gas turbines may not be justified. The commenters further stated that the lessee should be required to demonstrate the safety and reliability of use of this gas in the specific situation and that the 50 ppm level is selected for safety reasons in circumstances requiring instrument bleed or pressure relief.

Response—This recommendation has not been adopted. The use of gas containing H_2S for instruments is considered an unsafe practice because of its toxicity and characteristic of accumulating in low or unventilated places. The use of gas containing H_2S for fuel is more appropriately handled on a case-by-case basis.

Comment—In § 250.67(m)(11), one commenter recommended replacing most of the paragraph consisting of the phrase "either externally coated * * * in corrosive concentrations" with the word "protected" contending that the word eliminates ambiguity.

Several commenters recommended revising the paragraph to provide for internal and external protection for corrosion and suggested wording for the paragraph.

Response—The recommendation to substitute the word "protected" for "either externally coated * * * in corrosive concentrations" has not been adopted. The regulation needs to specify the acceptable means of corrosion protection.

The recommendation to revise the paragraph to provide for internal and external protection for corrosion has been adopted.

Comment—In § 250.67(m)(12), several commenters suggested the paragraph pertaining to threaded connections be deleted. The commenters contended that there is no technical justification to limit the use of tapered thread designs. This will preclude use of autoclave type or Hydril™ and other proprietary-type threads.

Response—This recommendation has been adopted and the succeeding paragraphs renumbered in the final rule.

Comment—In § 250.67(m)(13), several commenters recommended that the paragraph be revised by replacing the phrase; "of H_2S-resistant materials" with the phrase, "suitable for use in H_2S environments," contending that H_2S resistant materials cannot be specifically defined for elastomer applications.

Response—The recommendation has not been adopted. The recommended change is not viewed as adding clarity to the intent of the paragraph.

Section 250.68, Training in well control, has been deleted from Subpart D and its provisions have been transferred to Subpart O.

Subpart E—Well-Completion Operations

Subpart E, Well-Completion Operations, and Subpart F, Well-Workover Operations, incorporate and update requirements contained in § 250.92 and OCS Order No. 6 regarding well-completion and well-workover operations. The updated requirements reflect experience in the field and technological advances. Well-completion and well-workover operations are a significant portion of oil and gas operations and involve a number of critical and dangerous tasks. Over 20 blowouts occurred in the OCS between 1966 and July 1, 1987, during well-completion and well-workover operations.

Portions of Subparts E and F have been revised in the final rule in response to comments received. Additional changes were made in an effort to clarify the requirement of the rule.

In response to the **Federal Register** Notice of March 18, 1986 (51 FR 9316), 14 comments were received from industry concerning Subpart E, 12 comments were received from industry concerning Subpart F, and 4 comments were received from other interested parties concerning Subparts E and F. A discussion of specific comments and MMS responses follows.

Comment—Several commenters offered general observations. One commenter strongly supported promulgation of Subparts E and F. One commenter expressed concern over the specific well-shutdown requirements during equipment movement. One commenter recommended that Subparts E and F be combined. One commenter recommended that the performance standards be compatible with all conditions and circumstances that may exist (i.e., freezing conditions, storms, age of equipment).

Response—The specific well-shutdown requirements during equipment movement are addressed in §§ 250.72 and 250.92 of the final rule. The recommendation to combine Subparts E and F was not adopted. These subparts deal with two separate and distinct types of operations; therefore, the requirements should be kept separate to avoid confusion. The performance standards in Subparts E and F are applicable to conditions and circumstances relating to well-completion and well-workover activities.

Comment—One commenter concurred with the methodology in § 250.70 of using performance-type standards to regulate operations. Another commenter thought that the proposed performance standards were too general in that (1) the wording "harm or damage" should be defined to mean any adverse impact, and (2) the wording should prohibit instead of just protect against "harm or damage."

Response—The recommendation to define the meaning of "harm or damage" was not adopted. The proposed definition is interpretive, as would be most definitions, unless numerical quantities are identified. Performance standards supplement but do not replace specific regulatory requirements. The title of § 250.70 has been changed to "General requirements."

Comment—The only commenter on § 250.71 concurred with the paragraph.

Response—The commenter's concurrence is appreciated. The text of § 250.71 was modified to more clearly define "well-completion."

Comment—Several commenters submitted suggestions on § 250.72 concerning the activities required or permitted during the movement of well-completion rigs on and off a production platform. Several commenters suggested that specific requirements be deleted and that the equipment movement be conducted in accordance with operators' approved General Plan for Conducting Simultaneous Operations. A number of commenters suggested that the well-shutdown requirements were excessive in that (1) the equipment required to shut in the producing wells was redundant, and (2) the shutting in of all producing wells on a platform was unnecessary. One commenter suggested that the movement of certain types of well-completion and workover rigs onto or off a platform should be exempt from the shutdown requirements for producing wells.

Response—The movement of a completion rig onto or off of a producing platform is a critical operation. However, recognizing that some platforms have more than one well-bay, the final rule only requires that wells in the same well-bay that are capable of producing be secured during rig movement operations. A General Plan for Conducting Simultaneous Operations does not normally include sufficiently specific detailed procedures for equipment movement. Thus, that document would be unsatisfactory for use in regulating such operations. It is recognized that a shut-in back-pressure valve may be a redundant piece of safety equipment. However, the final rule only requires the back-pressure valve on wells from which a rig or related equipment is to be moved prior to removing the BOP system and installing the tree. A shut down limited to the well that is to be worked on or to those wells in the area adjacent to that well leaves the other producible wells in the wellbay too vulnerable to damage during equipment movement. Also, it should be noted that a well that is shut in at the surface by closing the master valve would not be shut in should the wellhead be knocked off.

Comment—Many commenters concurred with the requirement for an emergency shutdown system (ESD). Several commenters suggested that a specific location for an ESD station be deleted. They suggested that using the "General Plan for Conducting Simultaneous Operations" required in proposed § 250.123 was sufficient as a regulatory requirement.

Response—The recommendation to delete the requirement for an ESD station near the driller's console or the well-servicing unit operator's work station in § 250.73 was not adopted. The location of the ESD station at a less accessible location may delay the activation of an ESD. Since the General Plan for Conducting Simultaneous Operations does not contain specific procedures for ESD stations, it is not an acceptable alternative. Moreover, the requirement for a General Plan for Conducting Simultaneous Operations found in proposed § 250.123 has been deleted from the final rule (see also the discussion for proposed § 250.82 that follows).

Comment—Several commenters suggested that swabbing and tubing pulling be added to § 250.74 as additional operations that require the

lessee to take appropriate precautions against the potential release of H_2S gas. One commenter suggested the phrase "on a well" between "conducted" and "in" be deleted. One commenter concurred with the requirement as written.

Response—These recommendations have been adopted. The operations added to the listing in § 250.74 of the final rule may lead to H_2S exposure. Section 250.74 has been modified by deletion of the phrase "on the well" from between "conducted" and "in" and by substituting "including but not limited to" for "especially during." Section 250.74 was also revised by replacing the phrase "and pulling pumps and packers" with the phrase "swabbing, and pulling tubing, pumps, and packers" in the next to the last sentence.

Comment—One commenter concurred with the requirement in § 250.75 for subsea completions as written. Another suggested that subsea well completions be designed and operated in accordance with proposed API RP 17A, Design and Operation of Subsea Production Systems.

Response—This recommendation was not adopted. Proposed API RP 17A is a new document and can be considered for incorporation by reference after appropriate review of the final API RP 17A to ascertain that the recommended practice provides for the desired level of safety and environmental protection. Section 250.75 was revised to assure a better understanding of what is required.

Comment—Several commenters objected to the specific requirement in § 250.76 that safety meetings be recorded in the operations log, suggesting that the operators should have the option of determining the document to be used to record safety meetings.

Response—The recommendation was adopted. The operator must record the date and time that each safety meeting is held. Revised § 250.76 requires that the information be recorded and available at the facility for review by MMS representatives.

Comment—Several commenters suggested that welding and burning operations should be conducted in accordance with § 250.52 and that other requirements contained in § 250.77 were redundant. One commenter concurred with the present wording.

Response—The recommendation that § 250.77 simply require that welding and burning operations be conducted in accordance with § 250.52 was adopted and the text of the section modified accordingly.

Comment—Several commenters suggested that certain requirements in § 250.78 pertaining to electrical requirements be deleted as redundant. One commenter concurred with the present language.

Response—Upon reconsideration, it was decided that § 250.78 should simply incorporate by reference the electrical requirements contained in § 250.53. Section 250.78 of the final rule has been revised accordingly.

Comment—One commenter concurred with the requirement in § 250.79 for well-completion structures on fixed platforms as written.

Several commenters recommended that the second and third sentences be deleted as items which the operator will consider as appropriate.

Response—The recommendation that the second sentence of § 250.79 be deleted was adopted. The text of that sentence merely enumerated conditions that affect platform loading. The recommendation to delete the third sentence of § 250.79 was not adopted. Platforms deteriorate with time and use; hence, in the interest of safety, it is necessary to ascertain that a structure continues to be capable of withstanding the loads that it is expected to experience during its continued use.

Comment—Several commenters suggested that the requirements in § 250.80 be expanded to allow the use of manually operated shutdown devices for diesel engines used in emergency situations or for continuously attended diesel engines. These commenters also recommended that further detailed studies be conducted on diesel-engine runaways prior to implemention of any requirements. A number of commenters suggested that the regulation be deleted, contending that it is a significant increase in regulatory burden without sufficient evidence that the requirement is necessary. One commenter stated that the shutdown device does not prevent engine runaway but only stops the engine in the event of it.

Response—The recommendation to expand the language of § 250.80 to allow continuously attended diesel engines to be equipped with manually operated shutdown devices was adopted. This change should cover most of the diesel engines being used in emergency situations. The recommendation to delete the requirement was not adopted. It is recognized that the function of a shutdown device does not prevent diesel engine runaway, but it can shut down a diesel engine before a fire occurs. Section 250.80 in the final rule permits the use of either remote operated manual or automatic shutdown devices for continuously attended diesel engines.

Comment—One commenter questioned the effectiveness of the safety device required in § 250.81. Several commenters suggested that the phrase "all units" be replaced with the phrase "conventional rigs," stating that the required safety device would not apply to all rigs and that hydraulic units that pull doubles are used for well-completion operations and the proposed safety feature is built in.

Response—It is recognized that units which do not have both a traveling block and a crown block do not need the safety device. Section 250.81 has been revised to provide that units which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block.

Comment—One commenter concurred with the provisions of § 250.82 as written. Other commenters addressing other provisions of this subpart suggested that the General Plan for Conducting Simultaneous Operations mentioned in § 250.123(d) supersedes the requirements in § 250.82.

Response—To avoid confusion, the requirement for submitting a General Plan for Conducting Simultaneous Operations has been eliminated. Therefore, proposed §§ 250.82 and 250.123(d) have been eliminated and submission of the plan is not required in the final rule.

Comment—Several commenters recommended that the authority in § 250.83 (now § 250.82) for the District Supervisor to initiate field rules be deleted. They contend that the operator is best equipped to evaluate the geological and engineering information and propose specific operating requirements for a field. One commenter commended the provisions of the regulation.

Response—The recommendation to delete the District Supervisor's authority to initiate the establishment of field rules was not adopted. In fields where there is more than one operator, MMS personnel have access to all the available geological and engineering data and information required to determine whether field rules are needed. Section 250.82 of the final rule has been modified to clarify that field rules may modify the specified requirements of Subpart E. Due to the deletion of proposed § 250.82, proposed § 250.83 has been renumbered § 250.82 in the final rule.

Comment—One commenter suggested that the requirement in § 250.84(a) (now

§ 250.83(a)) of prior approval of well-completion operations be deleted. Several commenters recommended that a provision for oral approval be added to the section. Many of these commenters also suggested that the last sentence giving criteria for approval be deleted so as to streamline the approval process, contending that the 30-day subsequent report contains all necessary information. Also, they suggested that approval requirements for MMS's Districts be standardized. One commenter suggested that the phrase "the completion objective" be substituted for the word "conditions" in the third sentence.

Response—The recommendation to delete the requirements prior to approval of well-completion operations was not adopted. These operations represent significant changes that require prior MMS review and approval. Oral approvals are provided for in § 250.6. The approval requirements of MMS's Districts have been standardized to the extent that the information to be supplied by the operator for a proposed completion (e.g., operating procedures and OCS subsurface conditions) has been standardized. The third sentence of § 250.83(a) in the final rule has been revised by replacing the phrase "conditions or plans" with the phrase "the completion objective or plans." Section 250.83 has been further modified by deleting the fourth sentence.

Comment—One commenter recommended in proposed § 250.84(b) (now § 250.83(b)) that the wording be revised to require submittals only for multiple completions and completions begun after a suspension of drilling operations, contending that simple single and selective single completions should be allowed to commence without prior approval. Several commenters suggested that the entire paragraph be revised to require only a brief description of the work to be performed, the completion objectives, and a statement on expected surface pressures. The commenters contend that further technical review by MMS is unnecessary and is both paper and manpower intensive since operators thoroughly review their well-completion plans, designs, and procedures. Several commenters suggested that proposed § 250.84(b)(4) (now § 250.83(b)(4)), dealing with H_2S precautions, is unnecessary and duplicative of § 250.74.

Response—The recommendation to allow certain well-completion operations to be conducted without prior approval was not adopted. In the past, single well-completion operations have been conducted and the rig moved off location without the driving of protective casing. Situations have occurred where these types of completions have then been damaged. Prior approval of these operations allows the District Supervisor to review the proposed procedures and require necessary protective measures. The recommendation that only minimal information be submitted was not adopted. Review of a brief description of proposed well-completion procedures by MMS representatives will assure the use of minimum standards for the safety of operations. It also permits MMS to conduct an analysis and comparison of the lessee's data and information with data and information not available to the lease operator. The required information is needed to provide for a comprehensive technical analysis of the proposed operation. Consistency in information submittal will aid in the consistency of the MMS-approval process. To further clarify what information is needed, the "type and weight of completion fluids" has been added to the information to be submitted for MMS review. The recommendation to delete proposed § 250.84(b)(4) (now § 250.83(b)(4)) was not adopted. The purpose of this provision was to require that information be submitted pursuant to § 250.67 of the final rule.

Comment—Several commenters recommended that § 250.85(b) be deleted, stating that the requirement is covered in § 250.85(a) and that prudent operations dictate that sufficient quantities of well-control fluids be maintained.

Response—The recommendation was adopted, and proposed § 250.85(b) was deleted.

Comment—One commenter recommended that proposed § 250.85(c)(2) be deleted, while several commenters recommended that proposed § 250.85(c)(3) be deleted. The commenters stated that these requirements pertain primarily to drilling operations, would be difficult and unnecessary to comply with in many operations, and that trip tanks would be sufficient for monitoring returns in cased-hole operations. One commenter recommended that the audible alarm device be eliminated as it would give too many false alarms because of fluid movement. Several commenters suggested that proposed § 250.85(c)(4) be renumbered as a separate provision not directly related to proposed § 250.85(c) (1), (2), and (3), since they reviewed this requirement as an operation which did not deal with equipment. One commenter proposed to delete the five stands as criteria for filling the hole because in some cases this may amount to a minimal decrease in pounds per square inch (psi). Several commenters suggested that a new paragraph be added that would exempt operations conducted under pressure (i.e., snubbing and coiled-tubing operations) from the requirements in proposed § 250.85.

Response—The recommendations to make proposed § 250.85(c)(4) a separate provision was adopted. The recommendation to eliminate proposed § 250.85(c) (2) and (3) was not adopted. Trip tanks are normally used to monitor the fill up when pipe is being removed from the hole. Returns need to be monitored at all times including when going in the hole on trips. That monitoring should include warning devices which minimize the chance of human error. The equipment required by the regulation can usually be installed without major modifications. The recommendation to delete the five stands as criteria for filling the hole was also not adopted. The pulling of stands and assuming a minimal decrease in psi may lead to a failure to recognize a swabbing action in the well.

The recommendation that a paragraph be added to exempt operations conducted under pressure was not adopted. The majority of completion operations are not conducted under pressure. When a completion operation is conducted under pressure, it will normally be conducted with a completion rig that is required to have the equipment. Due to the deletion of proposed §§ 250.85(b) and 250.82, § 250.85(c) (1), (2), and (3) have been renumbered as § 250.84(b) (1), (2), and (3) and proposed § 250.85(c)(4) has been redesignated as § 250.84(c).

Comment—Several commenters recommended deletion in § 250.86(a) (now § 250.85(a)) of the requirement to submit a well-control procedure if the expected surface pressure exceeds the working pressure of the annular preventer. They stated that prudent operations dictate that the annular preventer would not be used in this situation. Therefore, the requirement is an unnecessary paperwork burden.

Response—This recommendation was not adopted. The submittal of a well-control procedure simply requires an additional statement on a form that will already be submitted. The well control procedure will serve to notify both the operator and MMS inspection personnel of the limited protection provided by an annular preventer. The second sentence of § 250.85(a) of the final rule requires that the working pressure rating of a

BOP system and the system components must "exceed" not just "equal or exceed" expected surface pressure to which they may be subjected. This change will provide a greater degree of protection for the operation and is consistent with the requirements contained in § 250.56 of the final rule. The phrase "except that the working pressure of the annular preventer need not exceed 5,000 psi" was deleted since this point should be covered by the operator's well-control procedures.

Comment—Several commenters recommended the deletion of § 250.86(b)(3) (now § 250.85(b)(3)) and the incorporation of requirements for tapered drill string into § 250.86(b)(2). The commenters stated that four preventers are adequate for safety when using a tapered drill string. One commenter questioned the need for additional preventers other than the ones required in proposed § 250.86(b)(1) when using tapered drill string. That commenter also suggested that provisions be included for the use of variable bore rams.

Response—The recommendation that only four preventers (one pipe ram for each size of string) be required when using tapered drill string was adopted for those instances where the expected surface pressure is less than 5,000 psi. In this situation, stripping could be done with a pipe ram and the annular preventer. Therefore, MMS has revised tapered drill string requirements in § 250.85(b)(3) (proposed § 250.86(b)(3)). The recommendation to include a provision for the use of variable bore rams was adopted. On the basis of comments received on § 250.56(g)(3) on drilling which recommended deletion of the use of a crossover sub, the provision for the use of a crossover sub was deleted from § 250.85(b)(3)(ii) of the final rule.

Comment—Several commenters stated that the locking devices in proposed § 250.86(c) (now § 250.85(c)) are not normally installed on the preventer stack and recommended that the word "on" be replaced with the word "for" in proposed § 250.86(c)(3). The commenters also suggested that the equipment described in proposed § 250.86(c)(5) be allowed to have a pressure rating equivalent to the ram preventers or anticipated surface pressures, whichever is less. They stated that higher pressure-preventer equipment may be in use than is required.

Response—The recommendation to replace the word "on" with the word "for" was adopted. However, the recommendation that the equipment specified in proposed § 250.86(c)(5) be allowed to have a pressure rating less than the pressure rating of preventer equipment was not adopted. Allowing associated equipment to have lesser pressure rating than the pressure rating of a preventer may lead to catastrophic failures when unexpected high pressures are encountered. In order to be consistent with § 250.56(d)(5), § 250.85(c)(5) in the final rule (proposed § 250.86(c)(5)) was modified to require that at least one of the valves on the kill line be remotely controlled, except that a check valve may be used in specific situations.

Comment—A commenter stated that there is no wrench to fit an inside blowout preventer as required by § 250.86(d) (now § 250.85(d)). Therefore, it was recommended that the phrase "inside BOP and" should be deleted.

Response—The recommendation was adopted and the phrase "inside BOP and" deleted from § 250.85(d) of the final rule.

Comment—Several commenters recommended that ram-type BOP's and related equipment required by proposed § 250.87(a) (now § 250.86(a)) be pressure tested to the lesser of (1) the rated working pressure of the equipment, (2) the maximum anticipated surface pressure, and (3) 70 percent of the minimum internal yield pressure of the casing. They also recommended that maximum anticipated surface pressure be included as criteria for determining the test pressure of the annular-type BOP's. They contend that the single-testing criteria of 70 percent of the minimum internal yield pressure of the casing for ram-type BOP's may be greater than 5,000 psi and would, therefore, require an upgrade in BOP equipment to 10,000 psi. They also contend that maximum anticipated surface pressure is a prime consideration in selecting a BOP stack and should, therefore, be included as a pressure-testing criteria. One commenter suggested that the rated working pressure of the casinghead or components in the BOP assembly be included as testing criteria for ram-type BOP's, contending that testing should not be conducted above the working pressure of the weakest link in the system.

Response—These recommendations have been adopted to the extent that "the rated working pressure of the equipment" has been incorporated as pressure-testing criteria for the ram-type BOP's and related equipment, and recognition is given to the fact that testing to "70 percent of the minimum internal-yield pressure of the casing" criteria may cause a considerable upgrade in equipment. The recommendation to add "the maximum anticipated surface pressure" as pressure-testing criteria for both ram-type and annular-type BOP's was not adopted. Methodologies used in determining the maximum anticipated surface pressure have been too varied for general acceptance as testing criteria. Those methodologies have included such concepts as (1) detailed technical calculations, (2) percentages of the anticipated bottomhole pressures, and (3) zero psi with the rationale that if proper mud weights are maintained, no surface pressures will exist. It is generally recognized that test pressures should not exceed the maximum working pressure of the weakest link. However, the recommended changes were not adopted since all associated equipment is required to have a rated working pressure at least equal to that of the ram-type BOP's pursuant to § 250.85(c) of the final rule. In order to avoid confusion or an excessive upgrade of equipment, "the rated working pressure of the equipment" should be the basis for determining the testing criteria for ram-type and annular preventers. However, in recognition of the limitations of these criteria, language has been added to § 250.86(a) which allows the District Supervisor to approve other testing criteria. Since variable bore rams were added in § 250.85(b) (proposed § 250.86(b)), a requirement was added to test surface BOP system components with water as this is deemed more appropriate than mud in detecting leaks. Section 250.86(a) (proposed § 250.87(a)) has been revised to incorporate the appropriate recommendations.

Comment—Several commenters suggested that stuck pipe and pressure-control situations should only be listed as examples of operations that may cause delays in BOP testing under proposed § 250.87(b) (now § 250.86(b)). The commenters stated that these two situations are not the only operations that may cause delays, and additional flexibility is needed. The commenters also recommended that only the affected seal be tested following repairs as provided in proposed § 250.87(b)(3). Their rationale is that the entire BOP system should not require retesting merely to verify the integrity of a pressure seal.

Response—The recommendation to treat stuck pipe and pressure-control operations as examples of operations that may cause delays in BOP testing was not adopted. Any other operations require the prior approval of the District Supervisor before BOP testing is delayed. Section 250.86(b)(2) of the final

rule (proposed § 250.87(b)(2)) was revised to permit delay in the testing of blowout preventer equipment other than blind or blind shear rams. The recommendation that proposed § 250.87(b)(3) specify that only the affected pressure seal will be pressure tested after repairs requiring the disconnecting of a pressure seal was adopted. Section 250.86(b)(2) and (3) of the final rule have been revised accordingly.

Comment—One commenter suggested that the paragraph in proposed § 250.88(a) (now § 250.87(a)) requiring that tubing strings have the necessary strength and pressure integrity and be otherwise suitable for its intended use be deleted because no operator would use unsafe equipment. One commenter concurred with the regulation. Several commenters recommended replacing the word "into" with the word "in" and deleting the phrase "or continued to be used." They stated that the wording is vague and that the requirement is duplicative and unnecessary. Also, they contend that economic justification for equipment replacement should be vested with the operator.

Response—The recommendation for deletions was not adopted. The regulation states the performance requirement that tubing be suitable for its intended use. Safety of operations and protection of the environment are major factors in decisions regarding equipment replacement. Economic justification must be considered, but it cannot supersede safety. The recommendation to replace the word "into" with the word "in" was adopted. Due to the deletion of § 250.82, § 250.88(a) has been renumbered § 250.87(a) in the final rule.

Comment—Many commenters recommended that the requirement in proposed § 250.88(b) (now § 250.87(b)) be deleted, stating that the regulation departs from performance-type standards, is open to various interpretations, and prescribes operations that a prudent operator would routinely do. Several commenters suggested that the phrase "every 30 days and the results submitted to the District Supervisor" be deleted from the requirement and replaced with the sentence "results of the evaluation will be maintained in the operator's well file." They stated that it is an unnecessary reporting requirement to submit the results to the District Supervisor. They also contend that the operator is best able to determine when the casing should be evaluated and that a time factor only serves as a basis for issuing Incidents of Noncompliance. Another commenter suggested that the phrase "30 days" should be replaced with the phrase "30 operating days," and the pressure-testing requirement be deleted from the regulation.

Response—The recommendation to delete the casing testing requirements from proposed § 250.88(b) was not adopted. If operators routinely evaluate the casing as they should, the regulation will not require any additional operations. The recommendation to delete the requirement from proposed § 250.88(b) to submit the results of casing tests to the District Supervisor was not adopted. The District Supervisor needs this information to evaluate the safety of continued operations on a well. The recommendation to either delete the 30-day timeframe or revise it to 30 operating days was also not adopted. Failure to include a timeframe in the final rule could lead to nonevaluations or different interpretations as to what is meant by prolonged operations. In recognition that pressure testing is only one of the possible methods of evaluating the casing integrity, it has been retained in the final rule as an acceptable method of testing. The limiting phrase "drilling or extended" has been deleted from § 250.87(b) of the final rule to clarify the requirements of the provision.

Section 250.88(c) (now § 250.87(c)) has been modified to include a requirement that the District Supervisor be notified immediately when a sustained casing pressure is observed. The District Supervisor needs this information to assess the situation and, if necessary, require the development and initiation of corrective action.

Comment—One commenter concurred with the regulation in proposed § 250.88(d) (now § 250.87(d)). Several commenters suggested that the phrase "in the vertical run of" be replaced with the word "on" stating that the number of blowouts attributable to wing valves was not given in the MMS rationale and, therefore, no data were presented to support the additional expense. They also stated that the requirement is not consistent with API RP 14C.

Response—The recommendation that the rule permit surface safety valves to be located on the tree and not specifically in the vertical run was not adopted. The surface safety valve is normally used to shut in wells. If it is located on the wing, it is more susceptible to damage than it would be if it were located in the tree. Additionally, this location will serve to contain well pressure in the lower part of the tree near the casinghead which is the strongest point.

Subpart F—Well-Workover Operations

Comment—One commenter concurred with the methodology in § 250.90 of using performance-type standards to regulate well-workover operations. Another commenter thought that the performance standards were too general in that (1) the wording "harm or damage" should be defined to mean any adverse impact, and (2) the wording should prohibit instead of just protect against "harm or damage." This commenter also recommended that specific training be included as regulatory requirements.

Response—The recommendation to define the meaning of "harm or damage" was not adopted. The definition proposed by the commenter is interpretive, as would be most definitions, unless numerical qualities are identified. Performance standards supplement but do not replace specific regulatory requirements. The need for specific training requirements is discussed elsewhere. The title of § 250.90 has been changed to "General requirements."

Comment—Several commenters recommended in § 250.91 that additional items be included as routine operations and that the additional operations should not require prior MMS approval. One commenter suggested that MMS approval only be required for work which affects the well-completion zone, stating that this would be simpler than enumerating routine operations.

Response—The recommendation to include additional activities in the list of routine operations was not adopted. All operations which involve pressure and affect a zone must be reviewed and approved by MMS personnel. The recommendation to eliminate the enumeration of routine operations and to only require approval of work that affects the well-completion zone was not adopted. The suggested elimination would lead to confused interpretations regarding what activity affects the zone and thus what activity requires prior approval.

Comment—Several commenters suggested that the specific requirement in § 250.92 to shut in producing wells be deleted and that the regulation simply require that equipment movement be conducted in accordance with an operator's approved General Plan for Conducting Simultaneous Operations. Several commenters suggested that the well shut-in requirements were excessive in that (1) the equipment required to shut in the wells was

redundant, and (2) the shut-in of all wells on the platforms was unnecessary. One commenter suggested that the movement of certain type well-workover rigs (snubbing units, wireline units) on or off a platform should exclude that platform from the well shut-in requirements.

Response—The movement of well-workover rigs onto or off of a producing platform is a critical operation. However, recognizing that some platforms have more than one well-bay, the final rule only requires that wells in the same well-bay that are capable of producing hydrocarbons to be secured during rig movement operations. A General Plan for Conducting Simultaneous Operations does not normally include sufficiently specific procedures for equipment movement. Thus, that document would be unsatisfactory for use in regulating such operations. It is recognized that a shut-in back-pressure valve may be a redundant piece of safety equipment. However, the final rule only requires this piece of equipment on a well when the tree or BOP stack is removed. Shutting in only the well that is to be worked on or only those in the area adjacent to the well to be worked on leaves the other wells too vulnerable to damage and subsequent loss of control during equipment movement. Shutting wells in only at the surface would not provide adequate protection, since there would be no protection if the wellhead should be knocked off. However, recognizing that some workover operations may involve movement of minimal equipment, a provision has been added which authorizes the District Supervisor to limit the application of the shut-in requirements during the movement of specific types of equipment.

Comment—Two commenters concurred with the requirement of § 250.93 concerning ESD's. Several commenters suggested that the specific location of the ESD station near the driller's console be deleted. They suggested that using the General Plan for Conducting Simultaneous Operations required in proposed § 250.123 was sufficient as a regulatory requirement.

Response—The recommendation to delete the requirement for an ESD station near the driller's console or the well-servicing unit operator's work station in § 250.93 was not adopted. Any other location of the ESD station may not be immediately accessible and may prevent, or at least delay, activation of an ESD. Since the General Plan for Conducting Simultaneous Operations does not contain specific procedures for ESD stations, it is not an acceptable alternative. It should also be noted that the requirement for submitting a General Plan for Conducting Simultaneous Operations has been deleted from the final rule.

Comment—Several commenters suggested that swabbing and pulling tubing be added to § 250.94 as additional operations that require the lessee to take appropriate precautions against the potential release of H_2S gas. One commenter suggested that the phrase "on a well" be deleted from the second line for clarity. One commenter concurred with the requirement as written.

Response—The recommendations have been adopted. The operations suggested by commenters that may lead to H_2S exposure have been added to the operations listed in the final rule (§ 250.94) that require appropriate precautions. Section 250.94 of the final rule also incorporates language which clarifies that an operator is not required to institute the required precautions to protect against H_2S exposure when a workover operation involves a well and zone which are known not to contain H_2S gas.

Comment—Several commenters recommended in § 250.95 that routine operations be deleted from the requirement for approval of subsea operations, stating that, as written, such operations as pulling the safety valves for inspection every 6 months will require MMS approval.

Response—The recommendation that routine operations for subsea completions be allowed without prior MMS approval was not adopted. When subsea technology and operations become routine, MMS will consider deleting "routine" operations from the prior approval process. The text of § 250.95 has been modified to assure a better understanding of what is required.

Comment—Several commenters objected to the requirement in § 250.96 that safety meetings be recorded in the operations log, suggesting that the operators should have the option of determining the document to be used to record safety meetings.

Response—The recommendation was adopted. The operator should be permitted to decide where to verify that safety meetings are held. Therefore, MMS has changed § 250.96 in the final rule to simply require that the information be recorded and available at the facility for review by MMS representatives.

Comment—Several commenters suggested in § 250.97 that welding and burning operations should be conducted in accordance with § 250.52 and that other requirements contained in § 250.97 were redundant. One commenter concurred with the present wording.

Response—The recommendation that § 250.97 simply requires that welding and burning operations be conducted in accordance with § 250.52 was adopted. Section 250.97 of the final rule has been revised accordingly.

Comment—Several commenters recommended that certain requirements in § 250.98 pertaining to electrical requirements be deleted as redundant. One commenter concurred with the present language.

Response—Upon reconsideration, it was decided that § 250.98 should simply incorporate the requirements of § 250.53 by reference in § 250.98. Under the final rule, § 250.98 requires that operations be conducted in accordance with the electrical requirements contained in § 250.53.

Comment—One commenter concurred with the requirement in § 250.99 for structures on fixed platforms as written. Several commenters recommended that the last two sentences of the requirement be deleted, stating that it should be left to the operator to determine the structural capability of the platform.

Response—The recommendation to delete the second sentence of § 250.99 was adopted. This sentence enumerated some of the conditions that affect loading and is not necessary. The recommendation to delete the last sentence of § 250.99 was not adopted. Platforms deteriorate with time and use; hence, in the interest of safety, it is necessary to ascertain that a structure is capable of withstanding the loads that it is expected to experience during its continued use.

Comment—Several commenters suggested that the requirement in § 250.100 be modified to allow for the use of manually operated shutdown devices for diesel engines used in emergency situations or diesel engines continuously attended. These commenters also recommended that further detailed studies be conducted on diesel-engine runaways prior to implementation of any requirements. A number of commenters suggested that the regulation be deleted, contending that it is a significant increase in regulatory burden without sufficient evidence that the requirement is necessary. One commenter stated that the shutdown device does not prevent diesel-engine runaway but only stops the engine in the event of runaway.

Response—The recommendation to modify the language of § 250.100 to

allow diesel engines which are continuously attended to be equipped with manually operated shutdown devices was adopted. This change should also cover most diesel engines that are being used in emergency situations. The recommendation to delete the requirement was not adopted. It is recognized that the function of a shutdown device does not prevent diesel-engine runaway, but it can shut down a diesel engine before a fire occurs. Section 250.100 of the final rules permits the use of automatic or remote operated manual shutdown devices for continuously attended diesel engines.

Comment—One commenter questioned the effectiveness of the safety device required in § 250.101. Several commenters suggested that the phrase "all units" be replaced with the phrase "conventional rigs," stating that the required safety device would not apply to all rigs and that hydraulic units that pull doubles are used for well-workover operations; therefore, the proposed safety feature is built in.

Response—It is recognized that units which do not have both a traveling block and a crown block do not need the required safety device. Section 250.101 has been revised to provide that units which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block.

Comment—One commenter concurred with the provisions of § 250.102 as written. Commenters, addressing other provisions of this subpart, suggested that the General Plan for Conducting Simultaneous Operations mentioned in § 250.123(d) supersedes the requirement of § 250.102.

Response—To avoid confusion, the requirement for submitting a General Plan for Conducting Simultaneous Operations has been eliminated. This action results in the deletion of § 250.102, which necessitates the renumbering of §§ 250.103 through 250.109.

Comment—Several commenters recommended that the authority in proposed § 250.103 (now § 250.102) for the District Supervisor to initiate field rules be deleted. They contend that the operator is best equipped to evaluate the geological and engineering information and propose specific operating requirements for a field. One commenter commended the provisions of the regulation.

Response—The recommendation to delete the District Supervisor's authority to initiate the establishment of field rules was not adopted. In fields where there is more than one operator, MMS personnel have access to all the available geological and engineering data and information required to determine whether field rules are needed. Section 250.102 of the final rule has been revised to clarify that field rules may modify the specified requirements of Subpart F. Proposed § 250.103 has been renumbered § 250.102.

Comment—Several commenters recommended that provision be made in proposed § 250.104(a) (now § 250.103(a)) for oral approval. Many of these commenters also suggested that the last sentence giving criteria for approval be deleted so as to streamline the approval process contending that the 30-day subsequent report contains all necessary information. Also, they suggested that approval requirement for MMS's Districts be standardized. One commenter suggested that the enumeration of routine operations listed in § 250.91 be deleted and that prior approval only be required for work that affects the well-completion zone. The commenter contends that such an approach would be simpler.

Response—The recommendation that a specific provision for an oral-approval process be added to proposed § 250.104(a) was not adopted. Section 250.6 authorizes oral approvals.

The approval requirements of MMS's Districts have been standardized to the extent that the information supplied by the operator for a proposed workover (e.g., operating procedures and OCS subsurface conditions) has been standardized. The recommendation to only require prior approval for work that affects the well-completion zone and to delete the definition of routine operations was not adopted. Such a procedure would lead to significant inconsistencies in operators' determinations of what affects the zone, or it would require MMS to enumerate what operations should be submitted for approval. Section 250.103 (proposed § 250.104) of the final rule has also been revised by deleting the third sentence. Due to the deletion of § 250.102, proposed § 250.104 has been renumbered § 250.103 in the final rule.

Comment—Several commenters recommended that the entire paragraph in proposed § 250.104(b) (now § 250.103(b)) be revised to require only a brief description of the work to be performed, the workover objectives, and a statement on expected surface pressures. The commenters contend that further technical review by MMS is unnecessary and both paper and manpower intensive since the operators thoroughly review their well-workover plans, designs, and procedures. Several commenters suggested that proposed § 250.104(b)(3) is unnecessary and duplicative of § 250.94.

Response—The recommendation that only minimal information be submitted was not adopted. A review of a brief description of proposed well-workover procedures by MMS representatives will assure the use of minimum standards for the safety of operations. It also permits MMS to conduct an analysis and comparison of data not available to the lease operator. The required information is needed to provide for a comprehensive technical analysis of the proposed operation. Consistency in information submittal will help in the consistency of the MMS-approval process. To further clarify what information is needed, the "type and weight of workover fluids" has been added to the information to be submitted for MMS's review. The recommendation to delete proposed § 250.104(b)(3) was not adopted. The purpose of the provision was to require that information be submitted pursuant to § 250.67.

Comment—Several commenters recommended that the additional information required in proposed § 250.104(c) (now § 250.103(c)) not be submitted separately but as part of the well-workover objective. They contend that further technical review by MMS is unnecessary and is both paper and manpower intensive since the operators thoroughly review their well-workover plans, designs, and procedures. One commenter was concerned that MMS's requirement of submitting a reason for abandonment of the present zone may lead to MMS forcing lessees to produce uneconomic zones.

Response—The recommendation was adopted to the extent that the additional information is to be submitted as part of Form MMS–331. The recommendation to drop the requirement for prior MMS review and approval of workover proposals was not adopted. Review of proposed well-workover operations is needed to assure the safety of those operations. That review and analysis may include data and information available to MMS personnel but not available to the operator proposing the work. It is not the intent of MMS to force lessees to produce uneconomic zones but to have all pertinent information submitted to MMS for the review and approval process. Therefore, § 250.103(c) of the final rule has been revised to incorporate appropriate language changes.

Comment—Several commenters recommended that the proposed § 250.105(b) be deleted stating that the

requirement is covered and that prudent operations dictate that sufficient quantities of well-control fluids be readily available.

Response—The recommendation to delete proposed § 250.105(b) was adopted.

Comment—One commenter proposed to delete from § 250.105(c) (now § 250.104(b)) the five stands as criteria for filling the hole because, in some cases, this may amount to a minimal decrease in psi.

Response—This recommendation was not adopted. The pulling of stands and assuming a minimal decrease in psi may lead to failure to recognize a swabbing action in the well. Due to the deletion of §§ 250.102 and 250.105(b), § 250.105(c) has been renumbered § 250.104(b).

Comment—Several commenters recommended that proposed § 250.105(d)(3) (now § 250.104(c)(3)) be deleted, and one commenter also recommended that § 250.105(d)(2) (now § 250.104(d)(2)) be deleted. The commenters stated that these requirements pertain primarily to drilling operations, would be difficult and unnecessary in many operations, and that trip tanks would be sufficient for monitoring returns in cased hole operations. One commenter recommended that the audible alarm device be eliminated as it would give too many false alarms because of fluid movement. Several commenters suggested that a new paragraph be added that would exempt operations conducted under pressure (i.e., snubbing and coiled tubing operations) from the requirements of proposed § 250.105 (now renumbered § 250.104).

Response—The recommendation to eliminate proposed § 250.105(d)(2) and (d)(3) (now § 250.104(c)(2) and (c)(3)) was not adopted. Trip tanks are normally used to monitor fill up when drill pipe is being removed from the hole. Returns need to be monitored at all times including when going in the hole on trips. That monitoring should include warning devices which minimize the chance for human error.

The equipment required by the regulations can usually be installed without major modifications. The recommendation that a paragraph be added to exempt operations conducted under pressure was not adopted. If operations are conducted under pressure on a workover rig, the required equipment will already be installed. If they are not conducted on a workover rig, the equipment requirements can be discussed with the District Supervisor. Due to the deletion of §§ 250.102 and 250.105(b), § 250.105(d) has been renumbered § 250.104(c).

Comment—Several commenters recommended deletion of the requirement to submit a well-control procedure from proposed § 250.106(a) (now § 250.105(a)), if the expected surface pressure exceeds the working pressure of the annular preventer. They stated that prudent operations dictate that the annular preventer would not be used in this situation; therefore, the requirement is an unnecessary paperwork burden.

Response—The recommendation was not adopted. The submittal of a well-control procedure simply requires an additional statement on a form that will already be submitted. The well-control procedure will serve to notify both the operator and MMS inspection personnel of the limited protection provided by an annular preventer. The second sentence of § 250.105(a) of the final rule requires that the working pressure rating of the BOP system and system components must "exceed" not just "equal or exceed" expected surface pressure to which they may be subjected. This change will provide a greater degree of protection for the operation and is a change consistent with requirements contained in § 250.56. The phrase "except that the working pressure of the annular preventer need not exceed 5,000 psi" was deleted since this point should be covered by the operator's well-control procedures. Due to the deletion of § 250.102, § 250.106 has been renumbered § 250.105.

Comment—Several commenters recommended the deletion of proposed § 250.106(b)(3) (now § 250.105(b)(3)) and the incorporation of the requirements for a tapered drill string into § 250.106(b)(2) (now § 250.105(b)(2)). The commenters stated that four preventers are adequate for safety when using a tapered drill string. One commenter questioned the need for any additional preventers than those required in proposed § 250.106(b)(1) when using tapered drill string. That commenter also suggested that provisions be included for the use of variable bore rams.

Response—The recommendation to require only four preventers (one pipe ram for each size drill string) when using tapered drill string was adopted where the expected surface pressure is less than 5,000 psi. In this situation, stripping could be done with a pipe ram and an annular preventer. Therefore, MMS has revised tapered drill string requirements in § 250.105(b)(3) of the final rule. The recommendation to include a provision for the use of variable bore rams was adopted. On the basis of comments received on proposed § 250.56(g)(3) on drilling which recommended deletion of the use of a crossover sub, the provision for the use of a crossover sub was deleted from § 250.105(b)(3) of the final rule.

Comment—In proposed § 250.106(c) (now § 250.105(c)), several commenters stated that locking devices are not normally installed on the preventer stack and recommended that the word "on" be replaced by the word "for" in § 250.105(c)(3). All commenters also suggested that the equipment in § 250.106(c)(5) be allowed to have a pressure rating equivalent to the ram preventers or anticipated surface pressure, whichever is less. They stated that higher pressure preventer equipment may be in use than is required.

Response—The recommendation to replace the word "on" with the word "for" in proposed § 250.106(c)(3) was adopted. However, recommendations that the equipment specified in proposed § 250.106(c)(5) be allowed to have a pressure rating less than the preventer equipment were not adopted. If associated equipment were allowed to have a lesser pressure rating than the preventer catastrophic failures might occur when unexpected high pressures are encountered. In order to be consistent with § 250.56(d)(5), proposed § 250.106(c)(5) (now § 250.105(c)(5)) was modified to require that at least one of the valves on the kill line be remotely controlled, except that a check valve may be used in specified situations.

Comment—Several commenters recommended that the BOP requirements in proposed § 250.106(d) (now § 250.105(d)) be reduced to one set of pipe rams and a tubing stripper or annular preventer. They contend that one pipe ram is sufficient and that the crown valve can serve as the blind ram on concentric workovers. Also, they state that on older platforms, there is not sufficient room to stack the equipment required and work in safety.

Response—The recommendations to lessen the BOP requirements of proposed § 250.106(d) were not adopted. If problems develop during the operations, equipment must be available that can be activated immediately. Two sets of pipe rams should always be available to allow for stripping into the hole. If safe operations dictate an alternate configuration, the alternative may be submitted for approval under § 250.3, Performance requirements; however, MMS believes that in some cases, platform modification may be necessary to provide levels of safety and environmental protection equal to or exceeding that provided for in the regulations. Proposed § 250.106(d) is now § 250.105(d) of the final rule.

Comment—In proposed § 250.106(g) (now § 250.105(g)), several commenters stated that there is no wrench to fit an inside blowout preventer. Therefore, the phrase "inside BOP and" should be deleted.

Response—The recommendation has been adopted and the phrase "inside BOP and" deleted from § 250.105(g) of the final rule.

Comment—Several commenters recommended that ram-type BOP's and related equipment required by proposed § 250.107(a) (now § 250.106(a)) be pressure tested to the lesser of (1) the rated working pressure of the equipment, (2) the maximum anticipated surface pressure, and (3) 70 percent of the minimum internal yield pressure of the casing. They also recommended that maximum anticipated surface pressure be included as criteria for determining the test pressure of the annular-type BOP's. They contend that the single testing criteria of 70 percent of the minimum internal yield pressure of the casing for ram-type BOP's may be greater than 5,000 psi and would, therefore, require an upgrade in BOP equipment to 10,000 psi. They also contend that maximum anticipated surface pressure is a prime consideration in selecting a BOP stack and should, therefore, be included as pressure-testing criteria. One commenter suggested that the rated working pressure of the casinghead or components in the BOP assembly be included as testing criteria for ram-type BOP's, contending that testing should not be conducted above the working pressure of the weakest link in the system.

Response—These recommendations have been adopted to the extent that "the rated working pressure of the equipment" has been incorporated as pressure-testing criteria for the ram-type BOP's and related equipment, and recognition is given to the fact that testing to "70 percent of the minimum internal-yield pressure of the casing" criteria may cause a considerable upgrade in equipment. The recommendation to add "the maximum anticipated surface pressure" as pressure-testing criteria for both ram-type and annular-type BOP's was not adopted. Methodologies used in determining the maximum anticipated surface pressure have been too varied for general acceptance as testing criteria. These methodologies have included such concepts as (1) detailed technical calculations, (2) percentages of the anticipated bottomhole pressures, and (3) zero psi with the rationale that if proper mud weights are maintained, no surface pressures will exist. It is generally recognized that test pressure should not exceed the maximum working pressure of the weakest link. However, the recommended changes were not adopted since all associated equipment is required to have a rated working pressure at least equal to that of the ram-type BOP's pursuant to § 250.105(c) of the final rule. In order to avoid confusion or an excessive upgrade of equipment, "the rated working pressure of the equipment" should be the basis for determining testing criteria for ram-type and annular preventers. However, in recognition of the limitations of these criteria, language has been added to § 250.106(a) to allow the District Supervisor to approve other testing criteria. Since variable bore rams were added in § 250.105(b) (proposed § 250.106(b)), a requirement was added to test surface BOP system components with water as this is deemed more appropriate than mud in detecting leaks. Section 250.106(a) (proposed § 250.107(a)) has been revised to incorporate the appropriate recommendations.

Comment—Several commenters suggested that stuck pipe and pressure control situations should only be listed as examples of operations that may cause delays in BOP testing under new § 250.106(b) (proposed § 250.107(b)). The commenters stated that these two situations are not the only operations that may cause delays, and additional flexibility is needed. The commenters also recommended that only the affected seal be tested following repairs as provided in proposed § 250.107(b)(3). Their rationale is that the entire BOP system should not require retesting merely to verify the integrity of a pressure seal.

Response—The recommendation to treat stuck pipe and pressure control operations as examples of operations that may cause delays in BOP testing was not adopted. Any other operations require the prior approval of the District Supervisor before BOP testing is delayed. Section 250.106(b)(2) of the final rule (proposed § 250.107(b)(2)) was revised to permit a delay in the testing of blowout prevention equipment other than blind or blind shear rams. The recommendation that the proposed § 250.107(b)(3) specify that only the affected pressure seal will be tested after repairs requiring the disconnection of a pressure seal was adopted. Section 250.106(b)(2) and (3) of the final rule have been revised accordingly.

Comment—One commenter suggested that in proposed § 250.108(a) (now § 250.107(a)) the paragraph requiring that tubing strings have the necessary strength and pressure integrity and be otherwise suitable for its intended use be deleted because no operator would use unsafe equipment. One commenter concurred with the regulation. Several commenters recommended replacing the word "into" with the word "in" and deleting the phrase "or continued to be used." They stated that the wording is vague, and the requirement is duplicative and unnecessary. Also, they contend that economic justification for equipment replacement should be vested with the operator.

Response—The recommendations for deletion were not adopted. The regulation states the performance requirement that tubing be suitable for its intended use. Safety of operations and protection of the environment are major factors in decisions regarding equipment replacement. Economic justification must be considered but it cannot supersede safety. The recommendation to replace the word "into" with the word "in" was adopted. Due to the deletion of § 250.102, § 250.108 has been renumbered § 250.107 in the final rule.

Comment—Many commenters recommended that the requirement in proposed § 250.108(b) (now § 250.107(b)) be deleted, stating that the regulation departs from performance-type standards, is open to various interpretations, and prescribes operations that a prudent operator would routinely do. Several commenters suggested that the phrase "every 30 days and the results submitted to the District Supervisor" be deleted from the requirement and replaced with the sentence "results of the evaluation will be maintained in the operator's well file." They stated that it is an unnecessary reporting requirement to submit the results to the District Supervisor. They also contend that the operator is best able to determine when the casing should be evaluated and that a time factor only serves as a basis for issuing Incidents of Noncompliance. Another commenter suggested that the phrase "30 days" should be replaced with the phrase "30 operating days" and the pressure testing requirement be deleted from the regulation.

Response—The recommendation to delete the casing testing requirement from proposed § 250.108(b) was not adopted. If operators routinely evaluate the casing as they should, the regulation will not require any additional operations. The recommendation to delete the requirement from proposed § 250.108(b) to submit the results of casing tests to the District Supervisor

was not adopted. The District Supervisor needs this information to evaluate the safety of any future operations on a well. The recommendation to either delete the 30-day timeframe or revise it to 30 operating days was also not adopted. Failure to include a timeframe in the final rule could lead to nonevaluations or different interpretations as to what is meant by prolonged operations. In recognition that pressure testing is only one of the possible methods of evaluating the casing integrity, it was retained in the final rule as an acceptable method of testing. The limiting phrase "drilling or extended" was deleted from § 250.107(b) of the final rule to clarify the requirement of the rule.

Section 250.108(c) (now § 250.107(c)) has been modified to include a requirement that the District Supervisor be notified immediately when a sustained casing pressure is observed. The District Supervisor needs this information to assess the situation and, if necessary, require the development and implementation of corrective action.

Comment—One commenter concurred with the regulation in proposed § 250.108(d) (now § 250.107(d)). Several commenters suggested that the phrase "in the vertical run of" be replaced with the word "on" stating that the number of blowouts attributable to wing valves was not given in the MMS rationale. Therefore, no data were presented to support the additional expense. They also stated that the requirement is not consistent with API RP 14C. One commenter recommended that the word "removed" be changed to "replaced" stating that it should not be necessary to change tree configuration unless the tree is to be replaced.

Response—The recommendation that the rule permit surface safety valves to be located on the tree and not specifically in the vertical run was not adopted. The surface safety valve is normally used to shut in wells. If it is located on the wing, it is more susceptible to damage than it would be if it were located in the tree. Additionally, this location will contain well pressure in the lower part of the tree near the casinghead which is the strongest point. The recommendation to require the equipment only if the tree is replaced was not adopted. When a tree is removed, it is an excellent time to make equipment improvements. Section 250.107 of the final rule has been modified by deleting the phrase "If the tree is removed during a well-workover operation," from the second sentence of proposed § 250.108(d).

Comment—In proposed § 250.109(b) (now § 250.108(b)), several commenters suggested that it is unnecessary to test the lubricator each time it is installed, stating that the lubricator union may be broken several times during workover operations on a well while changing wireline tools and that retesting after each change would create unnecessary delays. Many commenters also recommended changing the word "well-head" to the word "well" stating that lubricators are not installed on the wellhead but on either the tree or the blowout preventer.

Response—These recommendations were adopted. Testing the lubricator each time it is installed would be time consuming and would not enhance the safety of the operation. Testing upon initial installation is all that should be required. A provision has been added which clarifies the condition under which a lubricator assembly is required. This is a commonly used piece of equipment and should present no major modifications in wireline operations. If there is well pressure, the assembly allows for the removal of the wireline and tools without stripping the annular preventer. Therefore, the section has been revised accordingly. Due to the deletion of § 250.102, § 250.109(b) has been renumbered § 250.108.

Subpart G—Abandonment of Wells

The provisions of this subpart were addressed in comments received in response to the proposed revision of the rule published in the **Federal Register** on March 18, 1986 (51 FR 9316), and a proposed revision to 30 CFR 250.44, Wellbore abandonment, published in the **Federal Register** on August 21, 1986 (51 FR 29947). The provisions of the proposed revision of § 250.44 have been incorporated into this consolidated rulemaking rather than being promulgated as a separate action. Subpart G now includes the provisions for protective structures on the seafloor where required and reporting requirements for wells that remain in a temporarily abandoned status. The latter revision provided the specific requirements for the temporary abandonment of a well pending a determination as to whether the well will be completed or permanently abandoned.

The final rule provides for the isolation of resource-bearing and freshwater-bearing zones to ensure protection of the environment and conservation of these resources. Further, the subpart provides for the minimization of structures on the OCS and the prevention of conflicts with other uses of the seafloor and the OCS. It provides for the temporary abandonment of a drilling well and allows the suspension of a former producing well until all of the wells of a particular structure are to be abandoned so that the abandonments may be accomplished in the most efficient manner while maintaining protection of the environment.

During the review of the proposed rule, several changes were identified that should make the language of the regulation clearer.

Subtitles were added to some sections to enhance readability and ease of reference. The phrase "including supportive well logs and test data" was added to § 250.111(a) to ensure that submittals include specific information needed by the District Supervisor to make the approvals where warranted. For the same reason, § 250.111(b) was changed from "results obtained" to "size of casing removed, depth of the casing removal point, and the amount of casing removed from the well."

The various paragraphs were reworded to indicate a specific volume of fill to be used as a minimum in each instance where needed, and wording was changed in some paragraphs to provide consistency in language when describing amounts of cement used.

Comment—One commenter proposed the deletion of a sentence in § 250.110 that no producing well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the District Supervisor. This commenter stated that a well can be profitable for one company to operate but not for another company with different overhead costs and that MMS should not have the authority to make a company continue to operate a marginal well or field when it is no longer in the best economic interest of that company to do so.

Response—This recommendation was not adopted. It is recognized that lessees may have different operating costs. The final rule provides for consideration of these differences by allowing the operator to demonstrate to the satisfaction of the District Supervisor that the well is no longer profitable to the operating company. It is not the intent of these regulations to require a lessee/operator to produce wells at a loss. However, the lessor, in exercising its responsibility for conservation of natural resources and prevention of waste, needs the opportunity to review the abandonment of producible wells or fields prior to action being undertaken.

Comment—Several commenters requested deletion of the general

requirement in § 250.110 to plug and abandon any well which is no longer used or useful for lease operations. Commenters felt this requirement was unreasonable. They stated that over the life of a structure, the number of nonfunctional wells on many platforms is large; production would be lost in an effort to individually plug each abandoned well; and a better method is to wait until all wells on a platform are nonproductive before plugging and abandoning, unless a well poses a hazard to safety or the environment.

Response—Section 250.110 has been modified to clarify the requirement. The purpose of the general requirements of this subpart is to ensure that all wells drilled will be plugged promptly and abandoned when no longer of use to the operator. It is recognized that, as a reservoir is depleted, the abandonment of individual platform wells completed in other reservoirs is not an efficient means of operation and, further, may result in a loss of production. As long as those wells that have been shut in due to a lack of productive capability do not pose a safety hazard and are not causing pollution of the environment, there is no compelling reason to require them to be abandoned individually.

Comment—Several commenters recommended the insertion of the phrase "written or oral" approval in the first paragraph in § 250.111. These commenters stated that former OCS Order No. 3 allowed plugging and abandonment operations to commence after obtaining an oral approval from the District Supervisor. This is critical from a practical standpoint when dealing with dry holes and well workovers where downhole conditions may dictate immediate action such as plugging and abandonment. Waiting for written approval before proceeding with these operations is considered impractical from a safety standpoint and onerous from an economic standpoint.

Response—This recommendation has not been adopted. Provisions for oral approval have been deleted from this section and consolidated in Subpart A, § 250.6, Oral approvals, since oral approvals apply to more than one section of the regulations.

Comment—One commenter recommended the addition of a provision for the abandonment of zones set up as through-tubing alternates, utilizing through-tubing bridge plugs and cement deposited by a dump bailer. This would be an abandonment method other than to clean out and abandon the wellbore as provided in § 250.112. This commenter suggested adding that the cement and plug set for isolation must be tested to a minimum of the calculated pressure differential of the two zones involved. This would satisfy the requirement of permanent abandonment.

Response—This recommendation was not adopted. The comment appears to address abandonment of a lower production zone by placing a bridge plug in the tubing and placing a cement plug within the tubing on top of the bridge plug by means of a wireline bailer. In general, MMS provides for the use of alternative technologies in § 250.3, Performance requirements. However, the suggested abandonment would not meet the requirements of the regulations under any circumstances. Abandonment of a single zone completion within a multiple-completion well by means of plugging the tubing is not sufficient to ensure the isolation of zones within the wellbore. The tubing must be removed and the casing perforations plugged as provided in this section.

Comment—Several commenters felt that the placement and setting depths of additional cement plugs should not be left to the discretion of the District Supervisor. The commenters contend that the requirement for cement plugs to isolate oil, gas, or fresh water zones should be sufficient and, therefore, the last sentence in § 250.112(a) should be deleted.

Response—This comment was not adopted. Well conditions like abnormal pressure, large pressure differentials, long sections of open hole, or other conditions may be encountered which may dictate additional cement plugs to prevent migration of formation fluids.

In meeting its responsibility to ensure safety of operations and prevention of pollution, MMS must retain the discretion to exercise an engineering judgment to require additional plugs where necessary.

Comment—Some commenters recommended a modification in § 250.112(b)(2) which would eliminate the 50-foot minimum cement plug inside the casing on the basis that it "will eliminate many nuisance requests for a deviation to the District Supervisor."

Response—This recommendation was not adopted. This section establishes minimum guidelines for cement plugs and retainers and establishes the requirement for a minimum of 50 feet of cement above the retainer. The MMS believes that a minimum cement plug of at least 50 feet will normally be necessary to assure the integrity of the cement plug across the casing shoe.

Comment—One commenter suggested new wording for the last sentence in § 250.112(b)(2) to clarify this requirement.

Response—The suggestion was adopted and the last sentence revised. In addition, § 250.112 has been restructured, and this requirement is now contained in paragraph (b)(1).

Comment—One commenter recommended changes in § 250.112(c)(1) to set the retainer above the uppermost perforated interval instead of above the top of the perforated interval and proposed a revision of the last sentence for clarification.

Response—The recommended language was not adopted. The abandonment of a well with multiple perforated intervals requires all perforated intervals to be isolated to prevent migration of fluids and pressure between zones in accordance with § 250.112(a). Minor editorial changes were adopted to provide the clarity sought by the commenter and to maintain consistency with the language of previous paragraphs.

Comment—One commenter proposed that the words "if set by displacement, or 10 feet on top of the bridge plug if placed with a dump bailer" be added to § 250.112(c)(2). The commenter asserts that when laying a balanced plug with tubing or drill pipe, 50 feet may be necessary to assure a good plug but that when spotting cement with a dump bailer, 10 feet should be adequate for corrosion protection and the formation of a redundant pressure seal.

Response—This recommendation was not adopted. The MMS has insufficient information to verify that a lesser volume of cement placed by the dump bailer method would provide equivalent safety of a 50-foot plug placed by the displacement method and has elected to maintain the 50-foot guideline for minimum protection against leakage.

Comment—Several commenters suggested an additional abandonment method of "A 200-foot cement plug shall be set by the displacement or bullhead method within 100 feet above the perforations." These commenters stated that this is often the way wells are abandoned in routine operations; yet special approval to effect this type of well abandonment operation is currently required.

Response—The recommended alternative provides for isolation of perforated intervals consistent with § 250.112(c). The recommendation was adopted in part as an additional alternative plugging method. However, the MMS cannot verify the use of the bullhead method as a common practice among OCS operators and has elected not to adopt this part of the commenter's recommendation.

Comment—At § 250.112(d), several commenters suggested an additional abandonment method by placement of a 200-foot long plug within the first 100 feet above the stub. This is often the method used for abandoning wells in routine operations. Currently, special approval is required to effect this type of well abandonment. The addition would simplify the paperwork and approval process.

Response—The recommendation was adopted because it provides the same degree of protection as a cement retainer or permanent bridge plug with cement cap. The paragraph has been rewritten accordingly. The recommended language has been modified to clarify that a plug 200 feet long is a minimum requirement.

Comment—Several commenters proposed the deletion of the word "mud" from § 250.112(h). They stated that a fluid of sufficient hydrostatic pressure should be all that is required by the regulations. "Mud" offers no advantage in some well-abandonment operations.

Response—This recommendation was adopted and the word "mud" was deleted. Although most drilling fluids are referred to as "mud," it is recognized that operators may use other fluids, such as seawater, in place of "mud."

Comment—One commenter recommended that § 250.112(h) be deleted entirely because the requirement that the density of this fluid be sufficient to exert a hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs has no bearing on the effectiveness of the plugs and that the length of the cement plugs and/or appropriate mechanical devices should be sufficient to withstand any differential pressure exerted across them.

Response—It is recognized that fluid density and hydrostatic pressure should be based on the well conditions at the time of abandonment and not necessarily on the formation pressure encountered while drilling. The text in § 250.112(h) has been revised accordingly.

Comment—Several comments were received regarding § 250.112(i). One commenter said that the proposed flexibility for site clearance requirements on abandonments in § 250.112(i) is a desirable feature but that a uniform 15 feet below mud-line requirement is not consistent with rules allowing platforms to remain in place in deeper waters where there is no concern for interference with fishing or navigation. The commenter recommended that the second sentence of this subparagraph be changed since it refers to "all obstructions" being removed, contrary to the flexibility provided in the first sentence. It was recommended that the sentence be revised as follows:

> The lessee shall verify in accordance with § 250.114 that the location has been cleared to the extent required by the District Supervisor.

Response—The recommendation was adopted. It was not intended to require site clearance procedures where the requirement for removal of a wellhead has been reduced or eliminated.

Comment—One commenter recommended that § 250.112(i) be modified to require that the District Supervisor consult with the affected States prior to making a determination on wellhead removal to assist the District Supervisor in determining whether a waiver of wellhead removal would affect other seafloor user groups, particularly commercial fishing interests.

Response—This recommendation was not adopted. The rule provides that removal of a subsea wellhead may be reduced or eliminated when its presence would not constitute a hazard to other users or multiple users, including commercial fishing. Commercial fishing or other uses would have been addressed in the lease sale environmental impact statements and specifically addressed in the EP's or DPP's which described the well. In addition, each plan is reviewed in detail by MMS, other Federal and State agencies, and local agencies and organizations through the mandates of the Act, the NEPA, and the CZMA. The MMS will consult with States and other interests when that action is appropriate with respect to a determination that a subsea wellhead need not be removed.

Comment—One commenter advised that they believe all equipment should be removed from the seafloor, unless it can be shown that removal would be more environmentally damaging than leaving the equipment in place and that this determination by the Regional Supervisor should be subject to consistency with the affected State's coastal management program.

Response—This recommendation was not adopted. The conditions of the requirement, as written, will substantially satisfy the concerns of the commenter for protection of the environment. The waiver of wellhead removal would be approved only when the remaining material would not result in a hazard for other users of the seafloor. This reduction in removal and site clearance procedures will not be permitted in any fishing, multiple use, or known hazards area. Further coastal zone consistency review does not appear to be necessary.

Comment—Some commenters felt that the depth at which the temporary plug is required to be set in § 250.113(a)(2) should be allowed to be deeper than the first 200 feet below the mud line. They recommended that the plug be allowed to be set within the first 500 feet below the mud line. This would allow for more weight when drilling the cement plug, particularly in shallow waters.

Response—This recommendation was not adopted. The MMS believes that, for temporary abandonment of wells which might be reentered, this recommendation would not provide any additional safety margin for reentry without significantly diminishing the objectives of the top plug requirement.

Comment—Several commenters proposed addition of an exemption from this requirement for casing strings which have not been drilled out. This addition would clarify the intent that casing which has not been drilled out needs no cement plug or bridge plug added at the base of the casing string. The float equipment and/or cement left in the casing would provide adequate isolation.

Response—The proposed addition was adopted for clarification. The proposed rule was not intended to require a plug where casing had been cemented, and the casing shoe and cement remaining in the casing had not been drilled out.

Comment—A commenter stated that the "site clearance" requirement in § 250.114 should be tempered by the "rigs to reefs" program.

Response—The "rigs to reefs" policy envisions circumstances under which a few offshore platforms might be left in place where the required artificial reef construction and maintenance permits are obtained from the U.S. Army Corps of Engineers (Corps). The U.S. position on offshore platform removal was developed in interdepartmental policy group meetings with representatives of the USCG, EPA, Corps, and State Department. Significant changes were not required in Title 30 of the Code of Federal Regulations to implement MMS's Rigs to Reefs policy.

Comment—Several commenters stated that it should not be necessary to submit a letter from a service company in order to verify site clearance in § 250.114. A sundry notice with the pertinent information should suffice. It is impractical to hold up submittal of required forms while trying to secure materials from outside sources when

certification by the lessee on a sundry notice is required. Therefore, they suggested a new paragraph (b) that would accept the certification by the lessee or operator submitted on Form MMS–331, Sundry Notices and Report on Wells.

Response—This recommendation was adopted. A Form MMS–332 with pertinent information filed by the lessee bearing the signed certification of the lessee as to the accuracy of data is legally binding and should suffice.

In the **Federal Register** Notice of August 21, 1986 (51 FR 29947), MMS solicited comments on a proposed rule amending § 250.44. Comments and responses to those comments follow.

Comment—Several commenters mentioned the relationship of the August 21, 1986, proposal with the March 18, 1986, proposal, noting that the requirements are different.

Response—The proposed rule in § 250.44 published on August 21, 1986, and the comments received from that proposal have been considered in developing the final rule to the March 18, 1986, proposed rule. This final rule, therefore, integrates the two proposals into a single final rule.

Comment—One commenter indicated that language should be added to the regulation to make it clear that the decision to temporarily abandon the well is that of the lessee.

Response—The rule has been revised to make it clear that the decision to complete or abandon the well is that of the lessee/operator.

Comment—A suggestion was made by several commenters to change the wording of the regulation to indicate that oral approval for the temporary abandonment may be granted. Some indicated that written application and approval would follow the oral approval.

Response—The operating regulations at 30 CFR 250.6 provide that, when written approval is required by the regulations, the lessee may obtain oral approval provided that it is followed by written confirmation. It is not necessary to repeat such a provision at each point in the regulations where a written approval is required.

Comment—A few commenters felt that approval authority for temporary abandonment should be delegated in writing from the Director to the District Supervisor.

Response—The delegation of authority is accomplished through the Department of the Interior Manual and the MMS Manual. The final rule reflects the authority delegated to the District Supervisor to approve temporary abandonment and the method for protection of obstructions left above the seabed resulting from a temporary abandonment.

Comment—One commenter felt that the rule as structured would preclude the lessee from doing additional testing of the well or using the well to test technology, such as recovery technology, while temporarily abandoned.

Response—The final rule establishes minimum requirements for temporary abandonment of wells and does not preclude reentering a well for any purpose, including testing or trial use of new technology. Upon the completion of such testing or trial use, the well must be properly conditioned for temporary or permanent abandonment.

Comment—One commenter felt that the regulation should specifically address redrilling or deepening of the well. Another commenter felt that two distinct classes should be addressed—that of the former exploration or delineation well and that of the former producer.

Response—The suggested distinctions are not necessary. The final rule does not distinguish between the type of well when obtaining approval for temporary abandonment. A well which is redrilled or deepened or a former producer would be treated in the same manner as any other well. The rule is directed at the preparation of the wellbore for temporary abandonment independent of the status of the well prior to abandonment.

Comment—One commenter suggested adding "glory hole" to the list of protective structures.

Response—The MMS recognizes that a "glory hole" may be viewed as a protective structure. Also, MMS recognizes that a protective structure could consist of means other than a mechanical structure. The MMS does not believe that the regulations prohibit techniques or mechanisms other than mechanical structures to protect an obstruction. Wellheads and other equipment located in a "glory hole" that places the structure far enough below the mud line to preclude their being an "obstruction" would not be subject to the protection requirements of this regulation or require additional protection.

Comment—Several commenters felt that a report every 6 months was excessive and that an annual report would suffice. Another commenter felt that such a report was duplicative of an existing requirement to report all casing stubs on the OCS on an annual basis.

Response—This recommendation was adopted. In lieu of individual reports, the requirement is changed to an annual report which lists all such temporary abandonments and describes the lessee's intentions to reenter and complete, or permanently abandon each of the wells.

Comment—Several commenters felt that the requirements for navigation marking were addressed by the USCG.

Responses—After further review, it is recognized that the USCG has authority for regulating the marking of structures on the seafloor and that these areas of concern are adequately addressed at 33 CFR Part 67, Aids to Navigation on Artificial Islands and Fixed Structures. The final rule was changed to read that markings must conform to USCG requirements.

Comment—One commenter felt that it should be made clear that protective structures were not required in water depths greater than 100 feet. Another felt that the depth of the requirement should be at the discretion of the Director.

Response—The requirement for a protective structure was changed in the final rule to be at the discretion of the District Supervisor based on water depth, type and location of a subsea wellhead or other obstruction, and the type and timing of fishing activities in the area. The water depth of 100 feet was based primarily upon past consultations with the fishing industry in the Gulf of Mexico, but the water depth may be deeper in other OCS Regions. The OCS Lands Act Amendments of 1978, 43 U.S.C. 1801(13), established that "the Federal Government must assume responsibility for the minimization or elimination of any conflict associated with such exploitation [of oil and gas resources]." Since fishing activities and, subsequently, the necessity for protective structures will vary from Region to Region, the installation of protective structures will be based on need rather than on arbitrary water depth criteria. As discussed in the response to a comment in § 250.112(i), commercial fishing activities and other uses of the OCS would have been addressed in the lease sale EIS. Such activities will also be discussed in more detail in site specific exploration or development and production plans and effects of the proposal evaluated in the NEPA environmental review. The permit for drilling and abandonment of the well, including any requirement for protective structures, would be approved by the District Supervisor based on the findings of environmental documents and site specific plan reviews. The District Supervisor will have the opportunity to consult with

other interested parties, as appropriate, prior to making final decisions on requirements for protective structures.

Comment—One commenter responded that the rule should make it clear that witnessing is a requirement for permanent abandonment not temporary abandonment.

Response—The section has been restructured to clarify that point.

Subpart H—Production Safety Systems

The requirements relating to production safety systems contained in OCS Order No. 5, "Production Safety Systems," and 30 CFR 250.41(b) have been revised to remove unnecessary and redundant provisions and are incorporated into Subpart H, Production Safety Systems, of the final rule.

Comments concerning proposed Subpart H were received from 21 commenters. This included eight oil and gas companies, nine companies from related industries, two trade organizations, one environmental group, and one Federal Agency.

The comments received suggested both editorial and substantive changes. The comments received and the changes from the proposed rule to the final rule are discussed below.

Comment—In § 250.120, four commenters objected to the requirement in the first sentence that "state-of-the-art methods" be used. Their objections were that the wording can be misinterpreted so as to require the continual retrofitting of existing facilities and that the use of BAST is already specifically addressed in § 250.22. In addition, several commenters objected to the requirement in the last sentence that production not commence until after a preproduction inspection. They felt that this could cause unnecessary startup delays.

Response—The recommendation has been adopted. The first sentence has been deleted and the last sentence modified accordingly. The modification to the last sentence adds some flexibility to the timing of the approval process for the production safety system and preproduction inspection.

Comment—In § 250.121, one commenter recommended adding the phrase "other devices, specifically safety valve locks and subsurface safety valve (SSSV) landing nipples" to the last sentence of paragraph (a). The commenter's position is that well completions that require a wireline retrievable SSSV must have attached to them a safety valve lock and be installed in a SSSV landing nipple to work properly in the completion installation.

Response—For the past several years, there appears to have been some confusion as to the requirements associated with safety valve landing nipples and locks. These requirements are not clearly stated in OCS Order No. 5 but are included in two referenced documents (i.e., API Spec 14A and ANSI/ASME SPPE-1). The requirements were defined in the referenced documents prior to their inclusion in OCS Order No. 5 in January 1980. Therefore, the proposed paragraphs (a) and (b) have been revised to incorporate the requirements for locks and landing nipples. This is a clarification of an existing requirement rather than a new requirement mandating retrofit of existing equipment. Therefore, existing wells not previously equipped with safety and pollution-prevention equipment (SPPE) certified landing nipples and locks will be allowed to continue to operate until such time as mechanical well problems develop which dictate their replacement.

Comment—There were several comments submitted concerning the specifications for surface safety valves (SSV's). Five commenters recommended that § 250.121(b) should not require operators with pre-SPPE SSSV's in inventory to replace them solely on the basis of this requirement. Their position is that operators have many valves in inventory which are performing safely and satisfactorily. Some of the commenters also recommended that a definition of the word remanufacture be included.

Response—The use of the pre-SPPE inventory valves will continue to be permitted. This issue is dealt with in § 250.126. The reference to API Spec 14A and valves which enter the manufacturer's inventory within 3 years of its qualifying performance test date has been deleted since this situation is covered in the SPPE Program documents. A definition for the term "remanufacture" has been added to § 250.126(b)(2) of the final rule.

Comment—In § 250.121 (c) and (d), several comments were submitted concerning surface- and subsurface-controlled SSSV's. They suggested revisions for the sake of clarity, and the change is not substantive.

Response—These suggestions were adopted and appropriate revisions made in the final rule.

Comment—Several commenters suggested that § 250.121(e)(1) should require the SSSV to be installed within 15 days in lieu of 2 days. Their reasoning was that the provision should be consistent with § 250.121(i) which allows removal of a wireline or pumpdown retrievable subsurface safety device for a period of 15 days without further authorization or notice.

Response—The recommendation was not adopted. The intent is to have the SSSV installed within 2 days after the well is stabilized. It should be noted that specific language was incorporated into paragraph (e)(1) to define actions that are considered critical and thus must be approved by the District Supervisor.

Comment—There were several comments submitted concerning § 250.121(e)(2). All comments suggested revisions for the sake of clarity.

Response—These recommendations have been adopted and incorporated into the final rule.

Comment—One commenter suggested rewording § 250.121(e)(3) so as to give the lessee complete discretion as to the necessity of flowing a well while the subsurface safety device is removed. The commenter contends that shutting in the well could cause damage to the well. The commenter also stated that since the platform must be manned when the safety valve is out of the well, there is no reason to require it to be shut in.

Response—This recommendation was not adopted. It is believed that the well should be kept shut in while the subsurface safety device is out of the well unless it can be shown that allowing the well to flow is necessary for a particular operation. The District Supervisor can address specific situations on a case-by-case basis.

Comment—In § 250.121(e)(4), several commenters suggested deleting reference to § 250.126 concerning SPPE-1.

Response—This recommendation was adopted. It is recognized that the SPPE-1 program constitutes requirements for quality assurance programs, attendant accreditation of producers of SPPE, and receiving malfunction/failure reports by operators; the SPPE-1 document does not include requirements for inspection, installation, maintenance, testing, removal, or field repair. In SPPE-1, only paragraph OE-2620 stipulates operator's responsibilities. The rest of the document is applicable to the producer of SPPE equipment. Any reference to operations such as inspection, installation, or testing of SSSV's should be in accordance with the appropriate API RP 14 document.

Comment—Several commenters suggested moving the text from § 250.121(f) to § 250.124. Their position is that this revision would enhance consistency within the document.

Response—This recommendation has been adopted since the provisions of § 250.124 address production safety-

system testing and records. The text of proposed § 250.121(f) has been moved to § 250.124(a)(1)(ii) of the final rule.

Comment—In § 250.121(g), several comments were received which recommend the inclusion of the phrase "an injection valve capable of preventing backflow." The commenters' position is that an injection valve installed in an injection well should adequately satisfy the intent of this section.

Response—This recommendation has been adopted. Paragraph (g) has been redesignated (f) in the final rule.

Comment—Several commenters suggested revisions to the wording of § 250.121(h) for the sake of accuracy and clarity of subject matter.

Response—This recommendation has been adopted and the suggestion incorporated into the rule. Paragraph (h) has been redesignated (g). In addition, language was incorporated to define actions that are considered critical and thus must be approved by the District Supervisor.

Comment—In § 250.121(i), one commenter suggested deleting the last sentence in paragraph (i)(3) which sets different requirements for satellite wells the same as other wells. Their position is that satellite wells need to be covered in the same fashion as platform wells. They also contend that operators should not have to deploy personnel to man a well in inclement weather conditions where there are not any accommodations.

Response—This suggestion has not been adopted. The response time for reaction to an undesirable event on a satellite well will be considerably longer than for a platform well. If circumstances warrant relief from this requirement, the District Supervisor has the authority to grant relief from the requirement. Paragraph (i) has been redesignated (h).

Comment—In § 250.121(i)(4), one commenter suggested that the wording "or unless the well is attended" should be incorporated at the end of the first sentence in the paragraph. The commenter's position is that flowing a well to maintain production and prevent loading up should be allowed if the well is attended.

Response—This suggestion has not been adopted. This type of operation should be approved by the District Supervisor on a case-by-case basis.

Comment—In § 250.121(j), two commenters recommended that the wording "other fire detection devices" be added to the last sentence. In addition, wording was suggested that would provide qualifications to cover older existing wells.

Response—The recommendation has been adopted. The proposed requirement may be too restrictive. Platforms exist with other types of systems which have been approved. It is also recognized that the recommended changes would allow industry to take advantage of new advancements in technology. The suggested wording has been incorporated into the rule. Paragraph (j) has been redesignated (i) and paragraph (k) has been redesignated (j).

Comment—In § 250.122, several commenters recommended adding a reference to the pipeline section. Their position is that pipeline safety devices are an integral part of the surface production-safety system.

Response—This suggestion has been adopted. Since requirements for those devices are contained in § 250.154, a reference to that section in § 250.122(b) would be appropriate.

Comment—In § 250.122(c), several commenters recommended adding wording which defined remanufacture.

Response—This suggestion has been adopted and a definition incorporated into § 250.126(b)(2).

Comment—In § 250.122(d), several commenters suggested deleting reference to § 250.126.

Response—The suggestion has been adopted. The SPPE–1 program constitutes requirements for quality assurance program, attendant accreditation of producers of SPPE, and receiving malfunction/failure reporting by the operator. The SPPE–1 document is not the primary source document for requirements for inspection, installation, maintenance, testing, removal, and field repair. In SPPE–1, only paragraph OE–2620 stipulates operator responsibilities. The rest of the document is applicable to the producer of SPPE equipment. Any reference to inspection, installation, testing, etc., of underwater safety valves (USV) and SSV's should be in accordance with the appropriate API RP 14 document, not SPPE–1. In addition, after reviewing the proposed rules, it was realized that § 250.122(d) could be interpreted as allowing leakage from SSV's and USV's. Even though API Recommended Practices allow leakage rates, MMS's current rule does not allow leakage from SSV's or USV's. Section 250.122(d) has been modified to maintain MMS's policy in the final rule.

Comment—In § 250.122(e), several commenters suggested that a number of provisions be deleted. Their position is that submittal of detailed design information for mechanical and electrical systems is a burdensome regulatory requirement for both Government and industry. The commenters also believe that this information has limited regulatory utility and should not be required. The requirement, "Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers," should suffice as evidence of proper design.

Response—This recommendation was not adopted. Detailed design information is needed in the evaluation of production facilities. However, in paragraphs (e)(4)(i)(A) and (B) of § 250.122, the wording regarding the required electrical system information was changed to make it consistent with wording incorporated in the Third Edition of API RP 500B, Recommended Practices for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms.

Comment—In § 250.123(b)(1), several commenters suggested revisions to the wording of this provision for the sake of clarity of the subject matter. They suggested that paragraphs (b)(1) and (b)(1)(iv) should be consolidated. In addition, they suggested that a grandfather clause be added so as to cover uncoded vessels.

Response—The suggestion has been adopted in part. Section 250.123(b)(1)(iv) was modified and merged into § 250.123(b)(1). However, a grandfather clause was not included in these regulations since all nonstamped vessels have been grandfathered in prior regulations. The intent of excluding the grandfather clause is to preclude the installation of any future uncoded vessels. A provision has been included in the rules which would allow the continued use of uncoded vessels only after justification is presented, and the prior approval of the District Supervisor is obtained.

Comment—One commenter suggested adding wording in § 250.123(b)(1)(i) to address redundant relief valves and to exempt them from pressure setting requirements.

Response—This suggestion has been adopted. It has been MMS's policy to exclude redundant relief valves from such requirements. Therefore, language was incorporated into the paragraph to exclude redundant relief valves from the requirement.

Comment—In § 250.123(b), several commenters suggested revisions to the wording for the sake of accuracy and clarity of subject matter. Four commenters suggested that the retention of obsolete pressure recorder charts serves no useful purpose. Their position

is that the MMS requirement should be revised so as to require retention of the most recent applicable charts. One commenter questioned when to run a chart so as to establish a pressure range.

Response—The recommendations concerning obsolete pressure recorder charts were adopted and appropriate wording incorporated to address this topic. With regard to when a chart must be run to establish a pressure range, MMS's position is that a new chart needs to be run when the pressure conditions change. This may be required weekly, monthly, yearly, or whenever the conditions change. Appropriate language has been incorporated into paragraphs (b)(1)(iii) and (b)(2)(i) of § 250.123 of the final rule to address this topic.

Comment—In paragraphs (b)(2)(ii)(A) and (B) of § 250.123, several commenters suggested editorial revisions for the sake of clarity of the subject matter.

Response—These editorial revisions have been incorporated into the rule. The wording "two automatic shutdown valves" was replaced with "two SSV's." This is a clarification of an existing requirement rather than a new requirement. The regulatory intent has been to consider the second valve as an SSV since it is used as alternate protection. Therefore, MMS will require the additional valve on the wellhead to meet the ANSI/ASME SPPE-1 requirements.

Comment—In § 250.123(b)(3), one commenter suggested that the paragraph be more specific when addressing safety sensors. In addition, it was recommended that safety sensors be equipped so as to permit testing with an external pressure source.

Response—These suggestions have been adopted, and appropriate language changes have been incorporated into the document.

Comment—In § 250.123(b), several commenters recommended deleting the regulation in paragraph (b)(4)(iii) requiring that the ESD schematic be kept on the platform. Their position is that this schematic will serve no purpose on the platform. In addition, all other schematics, safe charts, deck plans, etc., required by § 250.122(e) can be maintained in offshore field offices.

Response—This suggestion has been adopted. Maintenance of this type of information on unmanned platforms is generally not practical, and the current regulatory requirement, which allows the information to be maintained on the platform *or* nearest field office, has worked well. In addition, in paragraph (b)(4)(ii), language has been incorporated to address the closure requirements of the SSV. The regulatory intent has been to require closure of the SSV within 45 seconds after automatic detection of an abnormal condition or activation of an ESD. This is a clarification of an existing regulation rather than a new requirement.

Comment—In § 250.123(b)(5)(ii), several commenters suggested deleting the automatic shutdown device on diesel engine air intakes. Their position is that the use of automatic air intake shutdown devices on attended engines and those intended for emergency use is not necessary and in some instances (cranes, fire pumps, etc.), may be highly undesirable from a standpoint of safety.

Response—This suggestion has been adopted to the degree that language has been incorporated into the regulation which permits continuously attended diesel engines to be equipped with either remotely operated manual or automatic shutdown devices. Diesel engines which are not continuously attended must be equipped with automatic shutdown devices. Diesel engines in emergency use are normally continuously attended.

Comment—In § 250.123(b)(6), one commenter recommended that the word "dehydration" in the first sentence be changed to "regeneration." The commenter's position is that this change would clarify the intent of the regulation, that is, to protect the reboiler section.

Response—The suggestion has been adopted. As proposed, the protection would have been required to extend to components such as contact towers, flash tanks, filters, and pumps. The object of the requirement is to protect the reboiler section. Therefore, to clarify MMS's intent, MMS has deleted the words "of all glycol dehydration units" from the final rule.

Comment—Several commenters recommended revisions to the wording in § 250.123(b)(7) for the sake of accuracy. In addition, four commenters recommended that reference be made to the requirements of API RP 14C. Their position is that there are requirements for pressure safety high, pressure safety low, and level safety low that are not always needed on vapor recovery compressors. The 1986 Edition of API 14C allows one to eliminate certain devices if conditions described in the safety analysis checklist are met.

Their position is that the proposed rules should continue to allow this exception procedure.

Response—These proposed regulations were based on the 1981 Edition of API RP 14C. The recognition of the provisions of the 1986 Edition of API RP 14C is being handled by a separate rulemaking action. The requirement of paragraph (ii) has been included in paragraph (i), and the subsequent paragraphs have been redesignated accordingly.

Comment—In § 250.123(b)(8), several commenters recommended editorial revisions to the wording.

Response—The text of this provision has been revised for clarification of its meaning. A sentence was added to address closed platform installations. The API RP 14G only addresses "open" platform installations. In addition, a statement concerning subfreezing conditions was included in paragraph (v). These changes provide flexibility in design while still requiring the use of proven equipment.

Comment—In § 250.123(b)(9), several commenters proposed wording which reflects MMS's policy presently followed. In addition, three commenters recommended that the proposed flow rates to define "adequate ventilation" exceed those rates included in API RP 500A, 500B, and 500C.

Response—It is recognized that API has investigated what constitutes adequate ventilation. The rule has been revised to recognize accepted standards for adequate ventilation. The revised paragraph defines adequate ventilation in an enclosed area and references API RP 500B in defining a classified area. It is believed that these changes will address the concerns of the commenters.

Comment—Several commenters recommended the addition of a reference to the electrical requirements under Subpart D in § 250.123(b). Editorial revisions to paragraph (b)(9) and the redesignation of paragraph (b)(10) as paragraph (b)(11) were also recommended. Their position is that this would make it consistent with the revisions made under fire- and gas-detection systems.

Response—This recommendation has been adopted to assure that production personnel are aware of these requirements. A new paragraph (b)(10), Electrical Equipment, has been added and paragraph (b)(10), Erosion, redesignated to paragraph (b)(11) in the final rule.

Comment—In § 250.123(b)(10), several commenters recommended changes to provide additional flexibility in maintaining erosion control records.

Response—These suggestions have been adopted in that the development and implementation of an information program of this type is usually handled by the technical staff at an onshore office. Since much of the data collected under an erosion control program requires extensive technical analysis and evaluation, maintenance of such

records in an offshore field office would serve no practical purpose. The lessee should have the flexibility to maintain such records at the most appropriate location. Therefore, appropriate revisions have been incorporated into paragraph (b)(10) (now designated (b)(11)).

Comment—Several commenters recommended deleting the word "installation" in paragraphs (c)(2)(i), (ii), and (iii) of § 250.123. Their position is that operations such as testing, recordkeeping, and inspections are not necessary if devices are not required to be installed. In addition, it was recommended that the words "downstream of the choke" be deleted from paragraph (c)(2)(ii) to permit covering pressure sensors which could be located on the upstream side of the choke.

Response—These recommendations have been adopted, and the rule has been revised accordingly. If a well is shut in, downstream sensors serve no useful purpose. Paragraph (c)(2)(iii) was eliminated. A flow safety valve (FSV) is required on a header if a well is disconnected since this safety device is designed to prevent backflow.

Comment—Several commenters suggested that simultaneous operations be approved by the Regional Supervisor in lieu of the District Supervisor. Their position is that approval by each MMS District Supervisor presents an unnecessary administrative burden and results in different requirements within each District. They conclude that regional approval would result in consistent and safer simultaneous operations.

Other commenters suggested that the "general plan for conducting simultaneous operations" supersede various requirements in other subparts.

Response—In order to clarify that a general plan does not supersede the requirements in other subparts of the regulation, the requirement that a plan be submitted in § 250.123 has been eliminated.

Comment—Several commenters recommended adding a new paragraph entitled "Welding and burning practices and procedures." Their position is that specific requirements for welding and burning operations are now found only under Subpart D, Drilling Operations. To assist production personnel in locating these requirements, a reference to § 250.52 of Subpart D should be included in Subpart H.

Response—This recommendation has been adopted, and a new paragraph (d) entitled "Welding and burning practices and procedures" has been added.

Comment—Several commenters recommended referencing API RP 14B in paragraph (a)(1)(i) of § 250.124. This is necessary for clarity and completeness since SPPE–1 does not contain the necessary information to comply with the requirements of this paragraph. Additional editorial changes were also recommended.

Response—These recommendations have been adopted. In addition, as discussed earlier, the text of proposed paragraph (f) in § 250.121 is transferred to paragraph (a)(1)(ii) in § 250.124. This will consolidate the testing requirements for subsurface safety devices. Paragraphs (iii) and (iv) are added to include testing requirements for tubing plugs and injection valves. These requirements are in OCS Order No. 5 and were inadvertently omitted from the proposed rules. The API RP 14 B which permits leakage rates for SSV's, USV's, SSSV's, and FSV's has not been adopted. This recommended practice permits leakage rates of up to 400 cc/min. for liquid and 15 cubic feet/min. for gas. On a heat release basis, both of these rates equate to approximately 900,000 Btu/hr. Since these leakage rates are unacceptably high, language has been incorporated into the regulations to permit leakage rates for SSSV's and FSV's of up to 200 cc/min. for liquid and 5 cubic feet/min. for gas. No leakage is permitted from SSV's and USV's.

Comment—Several commenters recommended changes in § 250.124(a)(2) and (3). They stated that the pressure safety valve (PSV) test tolerance in API RP 14C Appendix D required by paragraph (a) is ± 2 psi. Their position is that this is not suitable for testing PSV's on atmospheric tanks which are usually set at less than one psi. Therefore, they recommended that disassembly and inspection of these devices should satisfy the intent of this section. In addition, it was recommended to include a paragraph to address shutdown valves located in liquid discharge lines which are activated by a vessel low-level sensor.

Response—This recommendation has been adopted in order to assure consistency with current regulatory requirements.

Comment—Several commenters recommended that § 250.124(a)(4) reference API RP 14C instead of § 250.126. This is because § 250.126 references SPPE–1 which in itself does not contain the information necessary to comply with the paragraph. Their position is that the SPPE–1 program constitutes requirements for quality assurance programs, attendant accreditation of producers of SPPE, and receiving a malfunction/failure reporting by the operator.

Response—This recommendation has been partly adopted. The SPPE–1 document does not include requirements for inspection, installation, maintenance, testing, removal, and field repairs. In SPPE–1, only paragraph OE–2620 stipulates operator's responsibilities. The rest of the document is applicable to the producer of SPPE equipment. Any reference to operations such as inspection, installation, and testing of SSV's should be in accordance with the appropriate API RP 14 document, not SPPE–1. The appropriate section of API RP 14H was referenced since this section specifically covers testing of SSV's.

Comment—Several commenters suggested word changes in § 250.124(a)(5) in the interest of clarity. Other commenters suggested that the leakage rates be increased from 200 cc/min. to 400 cc/min. for liquid and from 5 cubic feet/min. to 15 cubic/min. for gas.

Response—This suggestion has not been adopted. The API permitted leakage rates of up to 400 cc/min. for liquid and 15 cubic feet/min. for gas are considered to be excessive. On a heat release basis, both of these rates equate to approximately 900,000 Btu/Hr. Therefore, the rule permits leakage rates for FSV's of up to 200 cc/min. for liquid and 5 cubic feet/min. for gas.

Comment—Two commenters recommended deleting the phrase "which can be nondestructively tested" in § 250.124(a)(6). Their position was that Temperature Safety Highs that cannot be nondestructively tested would be replaced every 6 months.

Response—This suggestion has not been adopted. The proposed change may require a process component to be shut in every 6 months.

Comment—Three commenters recommended addressing testing of fire detectors in § 250.124(a)(8).

Response—This recommendation has been adopted. Specific wording addressing "nondestructive" and "open flame" testing has been included in the final rule.

The requirements of § 250.125, Safety device training, have been transferred from Subpart H to Subpart O.

Comment—Several commenters recommended the API Quality Program API Spec Q1 as an option to the ANSI/ASME SPPE–1 program in § 250.126. Their position is that the new API program for equipment quality is comparable in many respects to MMS's proposed requirements in § 250.126.

Response—The MMS agrees that it may be appropriate to recognize other

quality assurance programs for the manufacture of safety and pollution-control equipment as being acceptable alternatives under the rule. Information has been added to § 250.126 directing interested parties where to submit alternate quality assurance programs for evaluation. The MMS is currently evaluating the API SPEC Q1 program as a possible alternate option to the ANSI/ASME SPPE–1 program.

Comment—There was one comment to delete the grandfather provision in the ANSI/ASME SPPE program.

Response—The MMS recognizes that the grandfather provision of existing rules has not been clearly understood. A new clarifying provision has been added to § 250.126 to resolve this matter. Under § 250.126, each lessee is to submit a list of SSV's, USV's, and SSSV's in its inventory as of the publication date of this rule. Safety and pollution-prevention equipment will remain on the list until the equipment is removed from service as a result of failure or malfunction or for remanufacture at which time the equipment will be removed from the list. Valves on that list will be acceptable for use in the OCS. All other SSV's, USV's, and SSSV's installed after the effective date of this rule must be manufactured, installed, and maintained in accordance with an MMS approved quality assurance program.

Subpart I—Platforms and Structures

Subpart I, Platforms and Structures, merges the provisions of the four regional OCS Orders No. 8 into a single set of regulations which apply generally to platforms and structures in the OCS. However, different geological and environmental conditions in the Regions continue to make it necessary to retain certain specialized requirements, e.g., icing effects in colder areas.

During MMS's review of the proposed rule and public comments, several revisions were identified in Subpart I that were editorial in nature and serve to more accurately reflect the intent of the regulation. These changes were not substantive and were made to the final rule. All references to MODU's and mobile drilling units were classified in this subpart as MODU's to achieve internal consistency and consistency with Subpart D. Similar editorial revisions were made to change the references to fixed platforms, fixed drilling platforms, platform, drilling unit, and structure to "platform" throughout this subpart and Subpart D.

Numerous comments to the proposed rule recommending changes editorial in nature, correcting referenced paragraphs, adding clarifying words or phrases, or revising the language of the regulation to increase clarity or eliminate redundancy were adopted by MMS, and the final rule has been revised accordingly. Many of those revisions are identified in the following discussion. Substantive comments and the respective responses are discussed under the heading of Comments and Responses.

Paragraph (f) of § 250.130 was rewritten to clarify the intent and eliminate redundant language. A new item (D) was added to § 250.131(b)(1)(v) requiring lessees in Alaska to submit plans for periodic inspections of platforms in accordance with § 250.142. The phrase "gravel or silt islands" was changed to "manmade islands" throughout the subpart since islands can be constructed of materials other than gravel or silt.

Section 250.131(b)(4)(iv) was modified to more accurately reflect the design criteria information that is to be submitted. The reference to inspection of platforms in § 250.132(a) was deleted since inspection requirements are addressed elsewhere in the subpart. Paragraph (c)(2)(iv) of § 250.134 was restructured to make it clear that, in general, the risk of experiencing maximum specified design events is to be held constant.

The words "construction and" were replaced with the words "fabrication or" in the introductory paragraph of § 250.135(c)(2) to better describe when the live loads would be encountered.

A phrase to better define the platforms to which the section applies, i.e., those located in areas associated with ice movement, was added to § 250.135(d)(4)(i). Similarly, the phrase "where appropriate" was added to § 250.135(e)(2). A phrase "for structural purposes" was inserted between the phrases "are used" and "the mechanical" in § 250.137(a)(2)(iv) to clarify when properties of material data are to be submitted.

The phrase "design earthquake loads" was changed to "loads induced by earthquake ground motions" to clarify the intent of § 250.137(c)(2)(iii).

The word "than" was inserted between the phrases "allowable stress less" and "the yield stress" at § 250.137(c)(4)(iv). While this does change the meaning of the sentence, the original omission was an error which could be inferred from reading the sentence. Paragraph (c)(5) of § 250.137 was restructured and revised to clarify the purpose of the required ductility analysis. The language of § 250.139(a)(1) was corrected to avoid unintentional exclusion of certain types of piles and platforms.

In § 250.139(b)(1)(i), the phrase "characteristics of the site" was added, and the phrase "familiarity of the area" corrected to "similarity of the area" to allow the use of appropriate available data and more clearly reflect the intent of the paragraph. The term "seafloor survey" was changed to "shallow hazard" survey in § 250.139(b)(1)(i)(A) and § 250.139(b)(2) to better characterize the survey to be conducted. Section 250.139(b)(1)(ii) was reworded to make clear that existing data could be used where deemed applicable and sufficient. The wording of § 250.139(b)(2)(ii)(B) was revised for clarity. The last sentence of § 250.139(b)(4)(i) was revised to clarify the intent.

In § 250.139(c)(1)(i), the phrase "analysis of the safety of the foundation" was changed to "design of the foundation" to more accurately reflect the intent of the requirement. Similarly, the phrase "with respect to changes in soil characteristics" was added to § 250.139(c)(2) to make clear the factors to which cyclic loading effects apply. The order of paragraphs (i) and (ii) of § 250.139(c)(3) was reversed to enhance clarity. Section 250.139(c)(4)(i) was rephrased to clarify the intent of the paragraph. The phrase "deteriorating soil strength" was corrected to "deterioration of strength" in § 250.139(c)(5)(ii).

The phrase "Post installation loadings" was changed to "In-place platform loadings" to more clearly define the loadings that are to be addressed by § 250.139(c)(6)(ii). The phrase "and between piles in a group" was added to § 250.139(d)(1)(iii) to clarify the interactive behaviors to be addressed by the regulation.

The title of § 250.139(e) was changed from "Gravity platform" to "Gravity platform foundations" to make it consistent with similar paragraph titles in this section. The phrase "local contact pressure due to irregular contact" was changed to "local pressures due to irregular contact" in § 250.139(e)(3)(iii).

The comments of a more substantive nature and MMS's response to those comments are presented below.

Comment—In the preamble to Subpart I, the MMS invited recommendations as to whether the requirements of the proposed Subpart I or the requirements of API RP 2A or those of the American Bureau of Shipping (ABS) would best assure the desired structural integrity of offshore platforms. Several commenters recommended the use of API RP 2A, and one commenter recommended the use of ABS rules for offshore installations.

Response—A new paragraph (g) has been added to § 250.130 which requires

that in addition to, and where they do not conflict with, the requirements in Subpart I, the requirements for platform design, fabrication, and installation specified in the documents entitled API RP 2A: Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms; or American Concrete Institute (ACI) 357R, "Guide for the Design and Construction of Fixed Offshore Concrete Structures," shall be followed when appropriate. These documents are widely used and are frequently updated to reflect the knowledge and experience of the offshore industry as it evolves. The specific design and construction details they contain can aid operators to meet several of the performance-oriented requirements of Subpart I.

The ABS rules were not deemed appropriate for inclusion in the final rule. The ABS's rules are similar to the requirements under Subpart I and also reference, in general, the API and ACI codes and standards.

Comment—The MMS also invited comments "as to whether alternatives to the third-party verification program are available which would better and more economically accomplish the purpose of that program." Several commenters responded to this invitation with essentially identical comments. Their response was that this program, or any alternative program, was unnecessary, costly, time consuming, and contributed little to the safety, security, and integrity of OCS platforms. They recommended the program be eliminated. A few of the commenters felt that the program had functioned well and recommended the program be continued. One commenter stated that the third-party verifier had supplemented existing company programs with a minimum of added burden.

Response—The recommendations to eliminate the program were not adopted. Experience since 1980 has shown that numerous problems have occurred in the design and construction of many of the structures subject to the requirements of the program. Technical oversight by MMS ensures that such problems are acknowledged and resolved. Further, it is our opinion that the level of effort and expertise of some lessees has risen, in part because of the existence of the Platform Verification Program. Several favorable comments were received from respondents who have had experience with the program. Further, incorporation of fabrication and installation Certified Verification Agent (CVA) inspections into an operator's inspection effort can minimize the lessee's economic burden.

Comment—One commenter suggested that a statement should be included in § 250.130(b) requiring that written approval by the Regional Supervisor be received by the lessee prior to installation of the platform or structure. The commenter also noted that timeframes were not specified for submittals or approvals.

Response—This recommendation that the written approval of the Regional Supervisor be obtained prior to platform installation was adopted and § 250.130(b) was revised accordingly. The recommendation that timeframes be specified for submittals and approvals for platform installation plans was not adopted. These plans are very complex, and each is designed to address problems unique to a specific platform proposed for a specific offshore location.

Comment—One commenter recommended that all platforms should be subject to the Platform Verification Program in § 250.130(c). The commenter suggested that the determination of whether or not a platform design is "novel" to a particular "area" as specified in paragraph (c)(4) is difficult to make since neither "novel" nor "area" is defined. The respondent also suggested that the determination of whether an area is seismically active requires the establishment of a threshold level in § 250.130(c)(5).

Response—This recommendation has not been adopted. Platforms installed in the shallow waters of the mature areas of the GOM need not be subject to the Platform Verification Program. Hundreds of these platforms have been installed over the years. A substantial number of designers and construction firms have a significant amount of experience in the design, fabrication, and installation of these platforms. The present MMS approval process provides adequate review of the plans for these platforms.

Good engineering judgment coupled with guidance found in documents such as API RP 2A are used to determine when the seismicity of an area is to be a significant design consideration. In seismically active areas, wave, wind, and current induced loads greatly exceed seismically induced loads. All loading conditions need to be checked. Thus it is not necessary to define a specific threshold level of seismic activity.

Comment—Several commenters expressed the view that industry has gained enough experience to change the threshold water depth limit for platform verification from 400 to 600 feet in § 250.130(c)(1). A few respondents suggested new wording for paragraph (c) which they deemed to be simpler and more straightforward than the proposed language.

Response—The recommendation to extend the threshold water depth from 400 to 600 feet has not been adopted. It is recognized that operations in the shallow water 400 feet and less of the GOM have a well documented record of satisfactory performance. That record is the reason for limiting the application of the detailed requirements of the Platform Verification Program to structures that are to be installed in over 400 feet of water. It is premature to extend the threshold water depth from 400 to 600 feet. The number of platforms installed in water deeper than 400 feet is relatively small, and the operating history of these platforms is relatively short. The modified rewording for § 250.130(c) was adopted.

Comment—One commenter recommended that the last sentence of § 250.130(d) be changed so that the definition of "major modifications" includes changes which "exceed or may cause to exceed the original design loading of the platform."

Response—This recommendation was not adopted. The wording of paragraph (d), as written, adequately covers the cited contingency. Such changes referred to by the commenter would indeed constitute a major alteration of the original plan, but they need not be specifically cited in the regulations.

Comment—One commenter recommended that major repairs of damage not require the approval of the Regional Supervisor as specified by § 250.130(e)(1) if such repairs restore a platform to original conditions.

Response—This recommendation was not adopted. A determination of whether the platform has been restored to its original condition is a matter of judgment, and the Regional Supervisor is responsible for making or concurring in that determination. For those cases where restoration exactly duplicates the original fabrication, the Regional Supervisor's approval should be readily obtained unless it is determined that the original conditions provide insufficient protection.

Comment—A new paragraph was proposed for inclusion in § 250.130 by a few commenters who felt that implementation of § 250.134 through 250.144 can best be accomplished by reference to well developed codes, standards, and practices which represent the constantly evolving knowledge and experience of the offshore industry. Two codes they consider most appropriate for this purpose are API RP 2A and ACI 357R.

Response—This recommendation was adopted with minor modifications, and a new paragraph (g) was added to

§ 250.130. The use of API RP 2A is a recognized means to fulfill Platform Verification Program requirements. The MMS's personnel participated in the development of the ACI 357R document.

Comment—A few commenters recommended that grid coordinates, as required at § 250.131(b)(1)(ii), be given in only one of the three grid coordinate systems with the selection based on the site location. They felt that any duplication of latitude and longitude coordinates, the Univeral Transverse Mercator, State Transverse Mercator, or State Lambert Coordinate systems is unnecessary.

Response—This recommendation was not adopted. The MMS, USCG, adjacent coastal States, and other users of marine location information utilize the different coordinate systems. The reporting of a platform location in all three systems reduces the potential for error, provides a quick and reliable mechanism for crosschecking the reported location, and ensures greater accuracy in the location of platforms on maps using one of the different coordinate systems.

Comment—A few commenters recommended that § 250.131(b)(4)(v) be deleted in its entirety because they believed that it could result in large volumes of work to prepare extensive drawings to satisfy this requirement. They further stated that they felt it to be an unnecessary submittal since "a platform is either designed within the requirements or it is not."

Response—This recommendation has not been adopted. Satisfying this requirement does not result in large work volumes or extensive sets of drawings. The sketches called for are small, one-line sketches with only the bent or row numbers indicated, which need not be to scale and can be drawn on size 8 ½" x 11" paper. For further details, the CVA or MMS can simply refer to the structural drawings called for in § 250.131(b)(1)(iii). While all platforms must be designed within the requirements, they are designed with varying degrees of conservativeness. These simple sketches allow the CVA and MMS to grasp the degree of conservativeness used in a particular design (or for selected members in a design). In many cases, this knowledge can be used to justify what may otherwise be judged questionable assumptions or results in other aspects of a platform's design. Such information aids the reviewer in evaluating all assumptions and results. The MMS has, in the past, required these sketches of lessees and has not received any negative comments regarding unreasonable workloads.

Comment—A few commenters recommended that the wording of the last sentence of § 250.131(b)(1)(iv)(B) be slightly modified to clarify the intent of this requirement. One commenter recommended its deletion, claiming fulfillment of § 250.131(b)(3)(ii) will make a fatigue analysis unnecessary.

Response—The recommendation to modify the last sentence was adopted. The respondent who recommended deletion did not demonstrate how a description of the effect of environmental and functional loads on the soil foundation required under § 250.131(b)(3)(ii) relates to the need for a structural fatigue analysis.

Comment—A few commenters felt that the requirement for certification of plans and specifications proposed at § 250.131(d) would greatly increase the volume of documentation to be submitted. They recommended that the requirement found in OCS Order No. 8 be retained, as it was more appropriate and addressed maintenance of the structure whereas the proposed language did not. They further felt that the term "detailed structural plans" needed to be defined.

Response—This recommendation was adopted and appropriate language changes made.

Comment—One commenter recommended that the notification period be changed from 1 week to 48 hours since the 48-hour notification is current practice and is sufficient notification.

Response—This recommendation was not adopted. Current practice, as found in OCS Order No. 8 requirements, is one week. This has been the practice since at least 1980 for GOM and Pacific OCS Regions and since 1982 for the Alaska OCS Region. Reducing this requirement to 48 hours would make MMS's scheduling its witnessing of load-out and tow-out activities difficult. Should this notification period present a problem on a particular project, then a waiver may be requested.

Comment—One commenter recommended that a section of the dispute procedures from the present MMS document "Operating Procedures for the OCS Platform Verification Program" be incorporated into § 250.132. This commenter felt that a means for settling disputes is needed.

Response—This recommendation has not been adopted. Disputes are inherent to the lessee/lessor relationship, and procedures for handling them are covered in the lease contract, the law, and the regulations.

Comment—One commenter expressed some concerns about the qualification and selection process for identification of a CVA as given at § 250.132(b)(1). The commenter felt that companies, as well as the individuals within the companies, should be qualified for verification projects. Further, the commenter recommended that a maximum of six to eight CVA companies should be prequalified by MMS and that only these companies should be allowed to act as CVA's. All of these companies would be required to maintain the capability to function as CVA's for all three facets of verification namely design, fabrication, and installation. The commenter further recommended that a uniform system of verification should be developed such that all projects are verified in essentially the same manner and with the same amount of CVA effort for each project.

Response—This recommendation was not adopted. It is not considered desirable to limit competition between CVA's. The respondent failed to demonstrate any significant benefit to the Government or to the lessee that would result if CVA's were required to perform all three CVA functions. Such a move could serve to prevent some of the more qualified CVA's from participating in the Platform Verification Program. Under current procedures, companies, as well as individuals within companies, can be qualified for CVA projects. However, the emphasis is placed on the individuals who provide the expertise and actually carry out the work. The qualifications of those individuals are of paramount importance to assuring effective implementation of the program. The Platform Verification Program was designed to allow lessees a degree of flexibility in defining the extent of the verification effort for a particular project. It is MMS's responsibility to assure that proposed verification plans satisfy these minimum requirements. Any specific CVA effort which exceeds these minimum requirements is at the lessee's option.

Comment—One commenter recommended that paragraphs (C) and (D) be deleted from § 250.132(b)(1)(ii) since company size and computer capability are not the only indications of qualifications.

Response—This recommendation has not been adopted. These paragraphs identify a total of six indications of qualifications for a CVA. All play a part in determining the ability of an applicant to properly function as a CVA, and the criteria cited in paragraphs (C) and (D) are indicative of the resources available to the person or company to accomplish the task.

Comment—One commenter recommended that the word "abstracts" in § 250.132(b)(2)(ii) be changed to "description" since it may, as used in this paragraph, imply that a lessee must reveal the actual computer programs.

Response—This recommendation has not been adopted. Webster's New Collegiate Dictionary defines abstract as "a summary of points usually presented in skeletal form." That definition describes the nature of the information to be submitted pursuant to this paragraph.

Comment—A few commenters recommended that the wording of § 250.132(c) be changed to allow resubmittal of only those portions of the plan which are affected by a change in status. Such an allowance would reduce the lessee's burden of resubmittal considerably in some cases. Several commenters also suggested the CVA should be able to substitute project personnel as necessary without having to resubmit the plan.

Response—This recommendation was adopted in modified form. A change in personnel assigned to carry out a particular project will require the submittal of the qualifications of the newly assigned personnel to MMS for approval. This procedure is necessary to assure that qualified personnel are being substituted for personnel previously approved by MMS. Other portions of the plan need not be resubmitted when there are no changes from those portions of the approved plan.

Comment—A few commenters expressed opinions regarding the requirements of paragraphs (1)(v), (2)(v), and (3)(iv) of § 250.133(a). One felt that the specified 6-week period, within which the CVA must submit his design report to MMS, is too short; the other felt that it is too long. Also, one considered the requirement that the CVA include a recommendation to MMS in the report to either accept request modification(s) or reject the proposed design to be an excessive and expensive burden to the operator. Each commenter applied their respective lines of reasoning to the fabrication and installation phases.

Response—These recommendations were not adopted. The 6-week submittal period is considered to be adequate for the CVA and reasonable for the lessee. To date, no serious problems have developed as a result of this requirement. Further, a CVA's recommendation to MMS regarding a lessee's platform design or construction can be construed as being burdensome and expensive only if the lessee fails to meet the minimum standards for safety. The CVA's recommendation is an informed opinion based on observed data and activities. The MMS needs this informed opinion to assure that the owner/operator has in fact complied with minimum safety requirements.

Comment—A few commenters feel that CVA's should not notify MMS of changes to design specifications or fabrication procedures as provided at § 250.133(a)(2)(iv) unless they have first informed the lessee of such changes, and the lessee has decided to accept them. Both commenters proposed new wording for this requirement.

Response—This recommendation was adopted. Any changes which the CVA might propose, which are unacceptable to the lessee, must be made acceptable to the lessee and MMS prior to MMS's approval of the fabrication plan.

Comment—One commenter recommended that the words "individuals or" be deleted from § 250.133(a)(5). This commenter found the wording regarding conflict of interest less specific than the commenter's suggested wording. The commenter felt that the suggested wording will be less likely to be misinterpreted by lessees.

Response—This recommendation was not adopted. As stated in the response to comments concerning paragraphs (b)(1) and (c) of § 250.132, the individual(s) who actually carries out the work is more critical to the success or failure of a platform verification effort than the company for which that person works. The number of different circumstances in which conflict of interest judgments must be made is too large to allow the development of a very specific all inclusive statement on the subject. Thus each situation must be judged on its own merit. However, the text of this paragraph has been revised to indicate that its provisions include the appearance of a conflict(s) of interest.

Comment—One commenter recommended that in § 250.133(b)(1) only one CVA be retained on each project, and that CVA's be used for all three phases (design, fabrication, and installation). The commenter doubted that a fabrication CVA can adequately judge the acceptability of deviations from the verified design documentation.

Similarly, the commenter feels that CVA's without design experience can have difficulty in assessing such things as the severity or the possible damage to the jacket during transport from the yard to the site.

Response—This recommendation was not adopted. The reasons are stated in the response to comments regarding proposed § 250.132(b)(1). Fabrication and installation CVA's do not necessarily have to have design experience in order to properly carry out their responsibilities. A design consultant or the design CVA can be consulted by the construction CVA's or lessee should a need for that expertise become apparent.

Comment—One commenter noted that only reasonably anticipated loadings should be considered under § 250.135 (e.g., earthquake loads in California and Alaska but not the Gulf of Mexico).

Response—No change was made in § 250.135. The requirements as presently worded do not require the consideration of loads which cannot reasonably be anticipated on the leasehold. Note response to the comment of § 250.137(c)(5).

Comment—One commenter recommended that the requirement at § 250.135(c)(4), regarding accidental loads, be eliminated in its entirety.

Response—This recommendation was not adopted. Use of accidental loads is not required, only the consideration of those loads. There have been cases where accidental loads were incorporated into the design of a platform. Quantification was necessary in those cases.

Comment—A few commenters recommended that the requirements of subparagraphs (iv), (v), and (vi) of § 250.135(c)(4) be eliminated due to the lack of viable estimated load data with which to accurately quantify loads.

Response—The recommendation was not adopted. The difficulties of accurately quantifying the loads addressed in these subparagraphs is recognized. For this reason, the requirement is worded to permit the lessee to make its best effort. Special problems require special treatment on a case-by-case basis. The MMS is aware of one platform design which considered and quantified explosive overpressure loads and of another platform design which incorporated mechanisms to dissipate the energy of colliding icebergs.

Comment—One commenter recommended that the requirement at § 250.135(c)(5)(ii) be eliminated since it precludes the consideration of wave directionality and platform orientation.

Response—This recommendation was not adopted. The MMS interprets § 250.135 to permit site specific studies to use wave directionality and platform orientation when warranted.

Comment—A few commenters recommended minor revision to § 250.135(d)(1)(vi) so as to allow the use of engineering judgment when applying the requirement to address hydrostatic loading.

Response—This recommendation was adopted, and appropriate language was added.

Comment—One commenter recommended that the requirement at § 250.136(c)(4) be eliminated because it "greatly increases up front design requirements and decreases future flexibility unnecessarily."

Response—This recommendation was not adopted. Basically, the considerations enumerated in this requirement involve common sense engineering judgment and will not greatly increase design costs or decrease future flexibility.

Comment—A few commenters recommended that the last sentence of § 250.137(c)(6)(ii) be deleted since the measure of redundancy is qualitative.

Response—This recommendation was not adopted. Although methods have been proposed which would quantify redundancy, this paragraph does not require the quantification of redundancy. In many cases, good engineering judgment is all that is necessary to determine whether or not a platform can be expected to fail catastrophically as a direct result of the failure of a particular structural member or joint. For those instances where such a condition is suspected, but is not intuitively or unquantifiably clear, the lessee should discuss the matter with the CVA and/or MMS.

Comment—A few commenters recommended that paragraphs (2), (3), and (4) of § 250.138(c) be deleted and replaced with two requirements which reference existing codes (ACI 357R and ACI 318–83).

Response—This recommendation was adopted, and paragraph (c) was revised accordingly.

Comment—Several commenters recommended that waiver provisions be stipulated at § 250.139(b)(1)(ii) for those instances where platforms are set in close proximity to each other, therefore, requiring only one site investigation.

Response—This recommendation was not adopted. Departures from specific requirements may be granted by the Regional Supervisor in accordance with § 250.3(b).

Comment—One commenter recommended a revision to § 250.139(b)(4)(iii) which would allow the use of existing borehole data where good engineering judgment deemed those data sufficient.

Response—This recommendation was adopted and the provision modified to specify that the Regional Supervisor may authorize a lessee to use existing borehole data.

Comment—One commenter recommended modification of the requirement at § 250.139(b)(4)(iv) to limit the required depth of soil boring to include only the depth of influence of a particular structure.

Response—This recommendation was not adopted. Departures from the specific requirements may be granted by the Regional Supervisor in accordance with § 250.3(b) in those instances where compliance with a specified requirement may not be necessary.

Comment—Two commenters recommended revising § 250.139(b)(4)(v) to add a requirement regarding packing of samples which will enhance the integrity of shipped soil samples.

Response—This recommendation was adopted. The text of the paragraph was modified to recognize that the careful packing of samples is important.

Comment—One commenter recommended that a number of requirements be added to § 250.140 including state-of-the-art motion instrumentation and barge motion monitoring equipment, post-tow destructive testing of selected nodes, and nondestructive examination (NDE) and destructive testing of all mill plate for main member nodes.

Response—This recommendation was not adopted. Under § 250.140(c), anticipated tow conditions and structure response analyses are required. Under § 250.133(a)(3), the CVA is required to review towing records and conduct a postlaunch survey of the jacket. Should the CVA have reason to suspect the jacket might have been damaged during the tow or launch, MMS can require a more thorough inspection of the jacket, including NDE and/or destructive testing. Based on our experience to date, more stringent written requirements do not appear to be justified.

Comment—Several commenters objected to the last two sentences of § 250.140(b). One commenter wanted these sentences eliminated; whereas others proposed alternative wording.

Response—The recommendation for alternate wording of this provision was adopted.

Comment—One commenter recommended modification of the requirements at § 250.141(b)(7) (iv) and (v) to eliminate review of towing records as a means of indicating whether or not possible overstressing of the platform has occurred. The commenter feels that visual inspection alone should be sufficient to detect damage.

Response—This recommendation was not adopted. Visual inspection alone is not sufficient to detect damage. The majority of the members and joints of a platform cannot be accessed while it is on a launch barge or under water. Tight fatigue cracks are difficult to detect visually. Therefore, determination as to whether or not actual tow conditions exceeded assumed conditions is important in that a more stringent visual and/or nondestructive examination may be necessary. If assumed tow conditions were not exceeded, then a routine visual inspection by the CVA, as called for in § 250.133(a)(3), is generally all that is necessary for platforms subject to Platform Verification Program requirements.

Comment—One commenter felt that the wording of paragraph (a) of § 250.142 did not clearly indicate whether it applied to all existing platforms or just to future platforms. This commenter felt that all platforms should be inspected at least once every 5 years unless circumstances dictate that an inspection be performed sooner. The respondent also felt that cathodic protection surveys should be carried out on a quarterly basis. Further, this commenter felt that more detailed inspections should be carried out for platforms older than 5 years. One commenter considered the wording of the requirement too vague and recommended that MMS adopt the ABS Rules for Offshore Installations. One commenter recommended that MMS require more frequent periodic inspections as a platform becomes older. One commenter recommended that inspections be carried out in periods of 3 to 5 years.

Response—The final rule has been revised to require approval of Regional Supervisor for any inspection interval greater than 5 years. This requirement applies to all platforms and structures, existing and future. The MMS is aware of the fact that many lessees already have their own periodic inspection programs in operation. As experience is gained under this rule, consideration can be given to whether there is a need to require more frequent inspections.

Comment—One commenter recommended that the requirement for submission of inspection records to MMS in § 250.142(b) be deleted because it is too vague. Several commenters recommended that inspection records be maintained by the lessee but not submitted to MMS. Such records would be made available to MMS upon request. This would minimize the lessee's paperwork burden.

Response—This recommendation was not adopted. Section 250.142 does not require the submission of inspection records. It requires the reporting of the platforms that were inspected during a 12-month period.

Comment—One commenter questioned the range of applicability of

the requirements for the submission of NDE testing records under § 250.144. Further, the commenter requested clarification of the term "NDE records."

Response—This requirement, as in the past, applies to all platforms and structures. "NDE records" applies to weld and, possibly, plate NDE results on all platforms and structures. It is recognized that only a minimum NDE may be carried out on many structures which are not subject to the verification program. The records must be retained by the lessee and copies made available to MMS when requested.

Subpart J—Pipelines and Pipeline Rights-of-Way

The DOI and DOT share responsibility for safety and prevention of pollution associated with offshore pipelines. The DOI has the responsibility for the approval of the installation and modification, including repair or abandonment of pipelines, under DOI's jurisdiction on the OCS. In addition, DOI grants or approves the modification of all rights-of-way for pipelines on the OCS.

At present, there are two classifications of pipelines on the OCS. They are as follows:

1. Lease term—These pipelines are owned and operated by a lessee or operator and are wholly contained within a single lease, a group of unitized leases, or contiguous (not cornering) leases of that lessee or operator.

2. Right-of-way—These pipelines are those which are contained within (a) the boundaries of a single lease or a group of unitized leases but are not owned and operated by a lessee or operator of that lease or unit, (b) the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator, (c) the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or (d) a block(s) which is (are) unleased.

Subpart J incorporates and updates requirements currently contained in 30 CFR 250.20, Pipeline approval; OCS Order No. 9, Oil and Gas Pipelines; and 30 CFR Part 256, Subpart N, Grants of Pipeline Rights-of-way on the Outer Continental Shelf.

Final Subpart J differs from the proposed Subpart J in that—

1. The numbering of some sections has been changed as a consequence of reorganizations, modifications, and minor editorial changes needed to consolidate technical, inspection, and reporting requirements for DOI pipelines and pipeline rights-of-way. As a consequence of this action, some other sections had to be renumbered to maintain sequence. Where a comment pertains to a section which has been redesignated, this fact has been noted in the response to the comment.

2. Specific requirements concerning right-of-way applications have been added with respect to shallow hazards, preservation of cultural resources, and nondiscrimination in employment forms. In addition, requirements concerning acceptance of rights-of-way have been clarified with respect to site, structures, or objects of historical or archeological value, and improvement and maintenance of the area covered by the right-of-way. As a consequence of this action, one section has been expanded and three new sections added. These provisions include clarification of requirements under the provisions of the March 18, 1986, proposed rule. Rather than relying on general wording of the requirements contained in the proposed rule, the specifications in these provisions will better inform the right-of-way applicant of what is expected and required.

In response to the **Federal Register** Notice of March 18, 1986 (51 FR 9316), comments were received from 18 companies and special-interest groups. These comments addressed various provisions of Subpart J. The comments and actions taken are discussed below.

Comment—Several commenters indicated that clarification was necessary in §§ 250.150 and 250.151 with regard to definitions and jurisdictional boundaries and the application of DOT requirements to pipelines approved under DOI regulations.

Response—These recommendations were adopted to the extent that § 250.150 has been modified to clarify the Regional Supervisor's role and to incorporate language of the MOU dated May 6, 1976, between DOI and DOT. Definitions have been addressed in § 250.151.

Comment—One commenter suggested more stringent terminology in § 250.150(a) in regard to pipeline interference with other uses on the OCS.

Response—This recommendation was not adopted. Its adoption would unnecessarily restrict the use of pipelines on the OCS. This would interfere with the multiple-use concept and would not allow OCS resources to be utilized in an equitable manner.

Comment—Several commenters recommended the deletions of the incorporation by reference in § 250.152 (a) and (b) of API RP 14E, Design and Installation of Offshore Production Platform Piping Systems, and of API RP 1111, Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines. It was stated that the design parameters would be too stringent for this design of risers and submerged components.

Response—These recommendations were adopted. Section 250.152(a) has been modified to incorporate by reference pertinent parts of the ANSI Code for Pressure Piping, B31.8, Gas Transmission and Distribution Piping Systems. The modification ensures that regulations reflect current BAST as reflected by recommended safe industry practice. Incorporation by reference of API RP 1111 in § 250.152(a) and API RP 14E in § 250.152(b) has been deleted.

Comment—Several commenters recommended the deletion in § 250.152(c) of the reference to Table 3.1 in API RP 14E concerning internal design pressure of valves since it had been eliminated from the Fourth Edition of API RP 14E referenced in § 250.152(b).

Response—This recommendation was adopted. Since the reference to API RP 14E in § 250.152(b) was deleted, a more appropriate reference concerning valves has been incorporated. Section 250.152(c) is now designated § 250.152(b)(1), (2), and (3).

Comment—Several commenters suggested the need for requirements in § 250.152(d) that would allow for redundant overpressure protection on a platform.

Response—Upon reconsideration, it was decided that clarification of the requirements in proposed § 250.152(d) was needed. Therefore, the paragraph was modified to indicate that the requirements contained in that section apply only to pipelines connected at subsea tie-ins. The paragraph has been redesignated § 250.152(c)(3).

Comment—Several commenters expressed concern that proposed § 250.152(g) appeared to require that pipelines withstand every environmental factor listed.

Response—The proposed rule was not intended to require that pipelines withstand every environmental factor listed. Therefore, in the interest of clarifying the intent, the paragraph was modified to require that operators design and maintain pipelines using technologies and precautions that would provide protection against reasonably anticipated environmental factors. The paragraph was redesignated § 250.152(f).

Comment—Several commenters recommended that the requirement in § 250.153(a)(3) of a minimum of 18-inch separation between pipelines be modified to allow the use of pipeline bundles.

Response—Pipeline bundles are considered as a single pipeline. Section

250.153(a)(3) was rewritten to clarify that 18-inch separations are required at pipeline crossings and obstructions. The rule does not apply to pipeline spacings within a bundle.

Comment—Several commenters suggested that the requirement in § 250.153(a)(4) for riser protection for those installed prior to the effective date of these regulations be deleted since there is no historical data of risers being damaged by floating vessels.

Response—This recommendation was not adopted. It is recognized that there have been few documented incidents of risers being damaged by floating vessels. However, the proposed rule merely states the Regional Supervisor's option of requiring protection when significant potential for damage is present.

Comment—In § 250.153(b) (1) and (3), several commenters recommended changes of the pressure test requirements for new, repaired, and out-of-service pipelines. These recommendations include the following:

1. That the test duration for new pipelines be limited to 2 hours in lieu of the 8-hour test proposed by MMS,

2. That the pressure test requirements on pipelines following repairs be modified to be consistent with pertinent DOT regulations,

3. That pressure test requirements on pipelines that have been out-of-service for more than 6 months be eliminated, and

4. That no pressure test be required if bolt-on-clamps or replaced components have been manufactured under a rigid quality assurance program.

Response—These recommendations were not adopted. However, upon reconsideration some modifications were made in the proposed rule. In general, pipelines under DOI jurisdiction operate at pressures equal to or greater than those pipelines under DOT jurisdiction. Products transported by DOI pipelines are also generally more corrosive than those products transported by DOT pipelines. Furthermore, the final regulations have not incorporated the welding requirements that are contained in DOT regulations. Therefore, MMS must rely heavily on the results of a pressure test. This reliance on the pressure test justifies maintaining the test duration at 8 hours in the final rule.

However, in light of some of the economic and environmental considerations raised by the commenters, the final rule has been modified with regard to pipeline repairs and to the placement of an out-of-service pipeline. These changes are as follows:

1. It was recognized that, under normal operations, a pipeline could be taken out-of-service for a period exceeding 6 months due to several reasons including development drilling, workover operations, or market constraints. Therefore, § 250.153(b)(1) has been modified to require a pressure test only after a pipeline has been out-of-service for more than 1 year.

2. Pipeline repairs will require a pressure test with water or processed natural gas to 1.25 times the maximum allowable operating pressure (MAOP) for 2 hours.

3. Section 250.153(c) was rewritten to require utilization of a full encirclement clamp able to withstand the anticipated pipeline pressure.

4. The Regional Supervisor has the option of requiring a pressure test to verify the integrity of the system if there is a reasonable likelihood to suspect that the pipeline has been weakened by external or internal conditions.

Comment—One commenter recommended the deletion in § 250.153(b)(2) of the pressure test saying that temperature changes at the surface would have little bearing on the changes occurring in the rest of the pipeline. Another commenter recommended that the required temperature recorders in § 250.153(b)(3) should only be used if temperature changes are anticipated.

Response—These recommendations were not adopted. It is recognized that during a pressure test, temperature recordings at the surface may have little bearing on changes occurring in the submerged portion of the pipeline. However, the riser piping exposed to ambient weather conditions could exhibit variations in pressure which may be interpreted as a leak in the pipeline. Utilizing a temperature recorder synchronized with a pressure recorder would serve as an additional aid in analyzing those variations in pressure.

It was not considered to be technically feasible to require the use of a temperature recorder only to measure anticipated temperature changes since weather conditions could not be accurately predicted. In addition, temperature recorders are relatively inexpensive and would not place an undue economic burden on the operator. These recorders provide useful and cost-effective data. The paragraph was redesignated § 250.153(b)(3).

Comment—Several commenters recommended the deletion of § 250.153(c) where it is required that a 48-hour notice be given to the Regional Supervisor prior to making pipeline repairs. The commenters indicated that repairs often need to be made quickly to reduce pollution making the 48-hour notice not practical.

Response—This recommendation was adopted. Flexibility is necessary for repair requirements. Therefore, the 48-hour notice requirement has been amended to require notification prior to the repair or as soon as practicable. The requirement has been moved to § 250.158(e) of the final rule.

Comment—Several commenters objected to the requirement in § 250.154(a) that the lessee be responsible for installing, operating, and maintaining safety devices on pipelines located on a lease but not owned by the lessee. The commenters recommended that § 250.154(a) be modified to require lessees to only ensure that regulatory requirements are fulfilled. In addition, the commenters recommended the elimination of the requirement that compliance with the new regulations be required for existing pipelines within 1 year of the effective date of the new regulations. The increases in cost and pollution potential were cited as the reasons for this recommendation.

Response—It is recognized that, in some situations, a lessee cannot physically install, operate, and maintain safety equipment on pipelines owned by others. The intent of § 250.154(a) was to require lessees to ensure that others provide for these safety devices when such pipelines are installed on their leases. The wording of the final rule reflects that intent. The proposed requirement that existing pipelines be required to comply with the new requirements within a year was deleted from the final rule.

Comment—Several commenters recommended that an additional subparagraph be added in § 250.154(b) to state that a pipeline would not have to be equipped with a high- and low-pressure sensor (PSHL) if a PSHL on an upstream component would sufficiently protect the pipeline.

Response—This recommendation was not adopted. Section 250.154(b)(3) states that departing pipelines shall be protected by high- and low-pressure sensors. Section 250.154(b)(3) does not necessarily require that pipeline sensors be installed. Upstream sensors on production equipment can be utilized when those sensors provide the required protection for the pipeline.

Comment—Several commenters recommended that § 250.154(b)(1) be modified to require that FSV be located downstream of automatic shutdown valves on incoming pipelines. This would allow the valves to be checked and repaired without increasing the

pollution potential by depressuring the line.

Response—This recommendation was adopted. Therefore, the phrase "located upstream of all safety equipment" does not appear in the final rule.

Comment—One commenter recommended that § 250.154(b)(1), (2), (3), (4), (7), (8), and (9) be moved to Subpart H since pipeline safety requirements are really part of the production safety systems and that the current division is confusing and redundant.

Response—This recommendation was not adopted. In order to facilitate the rapid location of pipeline requirements, most of the requirements pertaining to pipeline matters were consolidated under Subpart J.

Comment—One commenter recommended the deletion of the requirements in § 250.154(b)(3) and (9) to shut in all production facilities on a platform with a high- and low-pressure sensor on a pipeline. The commenter stated that the continuation of gas production would not present any safety or pollution hazard if oil production operations were shut in. The only shut-in valve needed on the oil system would be the pipeline pumps since most systems have storage capacity. In addition, the commenter noted that MMS approves Safety Analysis Function Evaluation (SAFE) charts which designate those production facilities that are shut in by a PSHL on a pipeline.

Response—This recommendation was not adopted. The use of the words "directly" or "indirectly" in § 250.154(b)(3) allows the operator adequate flexibility in designing safety shutdown systems. Section 250.154(b)(3) does not require that in every case the entire production facility be shut in immediately. Factors such as storage can be considered on a case-by-case basis when SAFE charts are submitted.

Comment—One commenter requested that set points for high- and low-pressure sensors on pipelines and pipeline pumps be specified in § 250.154(b)(3) and (9).

Response—This recommendation was adopted. The set points for high- and low-pressure sensors on pipelines and pipeline pumps are now included in § 250.154(b)(3) and (9). These set points will be 15 percent above and below the normal operating pressure range of the pipeline; however, the high pilot shall not be set above the MAOP of the pipeline. These settings will coincide with those specified in Subpart H for processing equipment.

Comment—Several commenters requested that in § 250.154(b)(5) the requirement for oil pipelines to have a volumetric metering system that would compare the input at the platform with deliveries onshore be eliminated. Their rationale was as follows:

1. There would be no technically feasible way of measuring input and output in a reliable manner (flashing liquids and two-phase flow).

2. Many pipelines are interconnected with many platforms, and therefore, attempts to compare inputs and outputs would be complex or impossible.

3. Any workable system would be too expensive.

4. The PSHL's already protect pipelines from leaks.

On the other hand, another commenter proposed that the requirement be made mandatory for all OCS facilities rather than discretionary as proposed.

Response—The recommendation to eliminate the requirement was not adopted. Under this provision Regional Supervisors may, at their discretion, require a volumetric metering system where one is practical and necessary to protect the environment. Due to the complexity of the Gulf of Mexico OCS Region's liquid hydrocarbon transportation systems, it is not anticipated that a volumetric system will be required on old pipeline systems in that Region. The requirement has been modified to give lessees the flexibility to utilize alternative leak detection systems. The recommendation to make the requirement mandatory was also not adopted since a mandatory requirement would not be practical in every instance.

Comment—Several commenters requested that the requirement in § 250.154(b)(6) to locate the FSV upstream of a block valve for a pipeline incoming to a subsea tie-in be modified to allow the FSV to be located upstream or downstream of the block valve. This would give the lessee maximum flexibility to design a system to prevent pollution. The commenters also requested that the requirement allow an exception for bidirectional pipelines. This change would help to reduce departure requests.

Response—The recommendation was adopted and the rule was amended accordingly.

Comment—Several commenters requested that the proposed rule in § 250.154(b)(7) allowing the installation of only an FSV for gas-lift and water-injection pipelines on unmanned well jackets be expanded to include all unmanned platforms. The commenters stated that the FSV would still provide effective protection from backflow. In addition, it was recommended that the paragraph be modified to indicate that a FSV would be needed upstream at the first inlet valve on the tree.

Response—The recommendation was adopted and the rule was amended accordingly.

Comment—Several commenters recommended that only verbal approval in § 250.154(c) be required in order to continue operations when safety equipment is placed out-of-service longer than 12 hours. The commenters noted that there would not be sufficient lead time to obtain written approval.

Response—This recommendation was adopted. The rewritten requirement is in a new § 250.158(d). Under the final rule the operator is required to notify the Regional Supervisor when pipeline safety equipment is taken out of and returned to service.

Comment—Several commenters recommended that the written approval requirement before pipelines are taken out-of-service in § 250.155(a) be deleted since, in many cases, there would not be sufficient time to obtain written approval from the Regional Supervisor. The commenters also noted that the phrase "temporarily out-of-service" was subject to misinterpretation.

Another commenter recommended that applications for abandonment be subject to consistency review by the relevant State.

Response—These recommendations have been partially adopted. The rewritten requirement is in a new § 250.158(c). Under the final rule the operator is required to notify the Regional Supervisor when a pipeline is taken out-of-service; however, a written confirmation is required when a pipeline is out-of-service longer than 60 days.

The recommendation for consistency review was not adopted. The abandonment of a pipeline is not an activity affecting land and water uses in the coastal zone.

Comment—Several commenters recommended that § 250.155(b) be rewritten to exempt abandoned pipelines in water depths greater than 200 feet since it is provided in § 250.153(a)(1) that pipelines installed in water depths of 200 feet or greater do not need to be buried.

Another commenter proposed that the regulation require the District Supervisor to consult with the States (for consistency purposes) prior to making a determination concerning abandonment.

Response—The recommendation to exempt pipelines in deeper water was not adopted. In the final rule the requirement is found in § 250.156(a)(1). It should be noted that § 250.153(a)(2)

requires all subsea valves and obstructions to be buried under at least 3 feet of cover in any water depth when they present a hazard to trawling operations. Unburied pipeline ends of abandoned pipelines in water depths greater than 200 feet may present the same hazard and, therefore, must also be buried. However, if the pipeline is located in waters where no trawling is done, a waiver from this requirement could be granted.

Consultation with States for coastal consistency review purposes is not necessary at the time of abandonment since abandonment of a pipeline is not an activity affecting land and water uses in a coastal zone. In cases where a pipeline is discussed in a Plan of Development and Production, issues relating to coastal consistency would have been addressed at the time of plan approval and would be a matter of record.

Comment—Several commenters objected to the specification of 6-month periods in § 250.155 (d) and (e). The commenters recommended the deletion of requirements for pipelines that were out-of-service for less than 6 months as specified in § 250.155(d) and proposed the deletion of the requirement in § 250.155(e) to flush and fill the pipeline with seawater because seawater would increase the corrosion rate of the pipeline.

Response—The recommendation was adopted. The revised requirements were redesignated § 250.156(b) (1) and (2). The final rule requires that all out-of-service pipelines, independent of time, be blind flanged or isolated with a closed block valve at each end and that they be flushed and filled with inhibited seawater if they are out-of-service for more than 1 year.

Comment—One commenter recommended that § 250.156 provides for notice to the affected State of corrective plans submitted to the Regional Supervisor for approval.

Response—The recommendation was not adopted. The MMS believes that incorporation of the recommended requirement into the regulations is unnecessary. The Regional Supervisor will consider the subject matter of corrective plans on a case-by-case basis. When the significance of the impact of activities described in a corrective plan warrants, the Regional Supervisor will consult with appropriate State officials. (This subject matter has been moved to § 250.157.)

Comment—Several commenters recommended the deletion in § 250.156(b)(1) of the requirement that plats submitted with new pipeline or right-of-way applications indicate the location of all other pipelines within 1,000 feet of the proposed pipelines.

Response—This recommendation was adopted. The final rule requires the depiction on the location plat of only those pipelines connected to or crossed by a proposed pipeline. The paragraph was redesignated § 250.157(a)(1).

Comment—Several commenters recommended the deletion of the requirement in § 250.156(b)(2) that the lessee include pilot settings and associated control lines on new pipeline or right-of-way applications since this information is not available at the time of application.

Response—This recommendation was adopted. Under the final rule it is not necessary to submit the proposed settings on sensing devices. However, the requirement for the depiction of associated pressure-control lines remains so that MMS can determine what specific shut-in functions are to be performed. The paragraph was redesignated § 250.157(a)(2).

Comment—Several commenters recommended the deletion in § 250.156(b)(3)(v) of the requirement that a new pipeline or right-of-way application include information on maximum and minimum operating pressures since this information is not known at the time of the application.

Response—This recommendation was adopted and the requirement deleted.

Comment—A commenter recommended that a new pipeline or right-of-way application in § 250.156(b)(4) require only a description of design precautions needed for unusual environmental factors.

Response—This recommendation was adopted. The final rule requires the operator to submit only those additional design precautions, other than the specified requirements, which were taken to withstand any environmental factor(s). The paragraph in the final rule is redesignated § 250.157(a)(4).

Comment—Several commenters recommended deleting the requirement in § 250.156(d) for the submission of an application to take a pipeline out-of-service.

Response—The MMS has adopted this recommendation to the extent that the submission of an application for approval to take a pipeline out-of-service was deleted. Under the final rule written notification is required if a pipeline is taken out-of-service when the out-of-service period exceeds 60 days. (See MMS response for § 250.155 (a), (d), and (e).) The requirement was redesignated § 250.158(c).

Comment—Two commenters objected to the requirement in § 250.157(b) of monthly pipeline route inspections. One commenter recommended that the inspections be made weekly in environmentally sensitive areas, and the other commenter recommended the deletion of the requirement since it was ineffective and costly.

Response—These recommendations were not adopted. Upon reconsideration it is recognized that to require a specific time interval for pipeline route inspections does not consider the different environmental factors which must be taken into account. Therefore, the final rule is written to allow the Regional Supervisor latitude to prescribe a time interval and method for conducting pipeline route inspections. Periodic inspection of pipeline routes serves as a means of detecting potential problems and avoiding major spills and leakages from pipelines. In the past, these periodic inspections discovered minor leaks which were repaired before they became major spillage. This requirement was redesignated as § 250.155(a).

Comment—Several commenters recommended that the requirement in § 250.157(c) for submittal of oral and written reports for spills and leakages to the Regional Supervisor be deleted because it duplicates the requirements in § 250.41(b) and doubles the paperwork burden on lessees. On the other hand, another commenter recommended that all spills and leakages, whether or not pipeline related, be reported to the Regional Supervisor.

Response—The recommendation to delete the requirement for the reporting of spills and leakages in § 250.157(c) was adopted. The recommendation to require the reporting of leaks and spills that are unrelated to a pipeline was not adopted. The reporting of unrelated spills and leakage to the Regional Supervisor would impose unnecessary additional reporting requirements on industry. Lessees are still under the reporting requirement in § 250.41(b).

Comment—Several commenters recommended in § 250.157(d) that lessees be given 30 days to file a report on the repair of pipelines rather than the 15 days listed in the proposed regulations. The commenters explained that once a repair has been made there is no need for urgency.

Response—This recommendation was adopted. In the final rule the reporting period is 30 days. The requirement is currently designated § 250.158(e).

Comment—Several commenters recommended that § 250.157(d)(2) be modified to indicate that pressure tests are not required after all pipeline repairs.

Response—This recommendation was adopted and the final rule modified (see response § 250.153(b) (1) and (3)). The requirement is designated § 250.158(e)(2) in the final rule.

Comment—A commenter recommended the deletion of § 250.157(f) which requires the lessee to file a plan for corrective action if environmental factors are detrimentally affecting a pipeline since requirements for damage, repair, relocation, and modification reports are already contained in the regulations.

Response—This recommendation was not adopted. The requirement is necessary to implement corrective action on a pipeline. The various reports cited by the commenter do not require corrective action from the lessees or operators. The requirement is designated § 250.158(g) in the final rule.

Comment—Several commenters objected to the requirement in § 250.157(g) that pipelines be inspected annually for corrosion by taking pipe-to-electrolyte potential measurements if the life expectancy of the cathodic protection cannot be determined. One commenter recommended that this requirement be made applicable only to those pipelines installed after the effective date of these regulations. In addition, the commenter recommended that the results and conclusions only be submitted to the Regional Supervisor upon request. One commenter recommended that the requirement be eliminated since the data only apply to a short interval of the pipeline being tested.

Response—These recommendations were not adopted. Corrosion is one of the primary causes of damage to existing pipelines. Intermittent inspection and submittal of reports would only partially address the problem of corrosion.

It is recognized that data readings taken at the platform provide information for only short intervals of the pipeline being tested; however, those readings serve as an indication of the effectiveness of the cathodic protection for the entire pipeline.

Comment—Several commenters stated in § 250.158(b)(5) that clarification was necessary to establish the frequency with which rental payments can be made on pipeline rights-of-way.

Response—The text of proposed § 250.158(b)(5) has been modified to indicate that the payments can be made on an annual basis, for a 5-year period, or for multiples of 5 years. These provisions are now contained in § 250.159(c)(2) of the final rule.

Comment—Several commenters observed under § 250.158(b)(8) that common carrier pipeline owners could be required by the Federal Energy Regulatory Commission (FERC) to purchase rather than transport hydrocarbons. They recommended that the regulation be amended to retain the common carrier's position as a transporter and not a purchaser of OCS hydrocarbons. One commenter proposed deletion of § 250.158(b) (8), (9), and (10) stating that they were included in the FERC regulations and should be omitted.

Response—These recommendations were adopted to the extent that the text of the proposed rule was modified to more precisely reflect the provisions of the Act. The revised provisions of proposed § 250.158(b) (8), (9), and (10) have been retained in the final rule to draw attention to FERC's authority to regulate pipelines in the OCS. Proposed § 250.158(b)(8) is designated § 250.159(c)(7)(i); proposed § 250.158(b)(9) is designated § 250.159(c)(7)(ii)(A); and proposed § 250.158(b)(10) is designated § 250.159(c)(7)(ii)(B) in the final rule.

Comment—Several commenters considered the filing fee of $1,400 mentioned in § 250.159(a) to be excessive.

Response—The requirement for a nonrefundable $1,400 filing fee was retained in the final rule. The amount was determined after conducting an in-house cost study. The study concluded that an average of 110 manhours were being spent to process each right-of-way application and that the $1,400 fee represented an appropriate user type fee to assess the pipeline applicant. The requirement is currently designated § 250.160(a) in the final rule.

Comment—A commenter recommended in § 250.159(e)(1) that the right-of-way applicant be allowed to give notice to the designated operator rather than to each lessee affected by a right-of-way application.

Response—This recommendation was not adopted. The MMS believes that it is important to ensure that all lessees receive notice of a proposed right-of-way across their leases. However, notice may be provided to the operator if the applicant provides documentation which indicates that the operator has been designated as an agent of the lessee(s) and is authorized to receive notice. The first two paragraphs of proposed § 250.159(e)(1) are designated § 250.160(c); the remainder of proposed § 250.159(e)(1) is designated § 250.161(d) in the final rule.

Comment—Several commenters recommended in § 250.160 (c) and (d) that the right-of-way granting process be revised to only require the applicant to submit evidence to the Regional Supervisor that an application has been submitted to the State(s). One commenter recommended that paragraphs (c) and (d) be combined and streamlined.

Response—These recommendations were not adopted. Section 250.160(c) and (d) address two distinct topics. Proposed § 250.160(c) has been rewritten for clarity while retaining content and is designated § 250.161(b). This provision provides that when a proposed pipeline route will adjoin and subsequently cross any State submerged lands, the applicant must submit evidence that the State has reviewed the application and submit any comments received as a result of that review.

Proposed § 250.160(d) has been deleted. This provision which requires CZM review of right-of-way applications, is not within CZMA jurisdiction by itself. Therefore, the provision was deleted for legal reasons. The CZM review of Plans of Development and Production will continue and pipelines which are discussed in such plans will be reviewed by CZM agencies when the plan is reviewed. In addition, pipelines entering State submerged lands will be reviewed by the State under provision § 250.161(b) and will also be reviewed by the State in connection with procedures governing pipelines in State submerged lands.

Comment—A commenter recommended that § 250.164 be limited to significant changes in use. The commenter also recommended that a change in flow direction not be considered a significant change. This would eliminate the need for approval of a change in flow direction by the Regional Supervisor.

Response—This recommendation was not adopted. A change in the direction of flow within a pipeline bears upon the safety equipment required under various regulations in Part 250. Since the modification of the safety equipment requires the approval of the Regional Supervisor, the change in flow direction through a pipeline also requires similar approval. Proposed § 250.164 is designated § 250.160 in the final rule.

Comment—One commenter proposed the establishment of procedures in Subpart J regarding documentation of pipeline locations and a mechanism for transferring information about the location of pipelines to contractors. The commenter stated that design standards were needed for pipeline risers as well as the establishment of procedures to ensure that operators will not produce

into a pipeline network without first being certain of its pressure integrity.

Response—This recommendation was not adopted. Subpart J is written to incorporate general performance standards on the design, installation, operation, and maintenance of pipelines in the OCS. An objective by MMS in drafting the final rule was to leave out unnecessary detailed procedural requirements where possible. Procedural guidelines can be addressed in an NTL or by developing a handbook of guidelines and procedures for pipeline applications. The incorporation of reference to technical documents which represent the state-of-the-art standards for riser design provide the design standards needed for pipeline risers. Also, the required safety systems, pressure test, and maximum allowable operating pressure limitations placed on pipelines are designed to protect the pressure integrity of pipelines in the OCS.

Comment—One commenter recommended that MMS modify Subpart J to clearly require the use of BAST to assure maximum environmental protection. The commenter stated that the regulations concerning pipeline burial, abandonment, and right-of-way did not satisfy the requirements of section 5(e) of the Act.

Response—This recommendation was not adopted. The provisions of Subpart J satisfy the requirements of section 5(e) of the Act. The referenced technical standards and practices that represent the BAST are incorporated into the final rule.

Subpart K—Production Rates

Subpart K, Production Rates, addresses in general, conservation of the hydrocarbon resources recoverable under Federal oil and gas leases. Specifically, the subpart addresses classification of reservoirs as sensitive or nonsensitive, establishment of Maximum Production Rates (MPR), the flaring and venting of gas, downhole commingling of oil and gas production, and enhanced oil and gas recovery operations.

Proposed Changes and Explanations

The requirements of §§ 250.16, 250.39, 250.55, 250.68, and former OCS Order No. 11, Oil and Gas Production Rates, Prevention of Waste, and Protection of Correlative Rights, in the GOM and Pacific OCS Regions were revised and incorporated into this subpart. The discussion of the subpart proposed in the **Federal Register** on March 18, 1986 (51 FR 9316), included responses to comments received as a result of the publication of a proposed revision of OCS Order No. 11 in the **Federal Register** on May 4, 1984 (48 FR 20151). Subpart K of this final rule includes revisions made after consideration of the comments received in response to the publication of the proposed rule on March 18, 1986.

Reconsideration of the proposed rule identified minor changes in the text of the proposed rule which would clarify the meaning of some of the provisions of Subpart K. Upon reconsideration of the proposed rule, it was decided that the final rule should include restrictions on the commencement of production from a well completion located within 500 feet of a property line. Compliance with these restrictions can avoid drainage situations across common property lines. Under GOM OCS Order No. 11, paragraph 14B, it was necessary for an operator to consult with adjacent lessees and obtain approval from the Regional Supervisor before a well less than 500 feet from a property line could be produced. These limitations force lessees to consider the correlative rights of adjoining lessees during the planning and execution of development drilling operations.

As a result, the provisions in 30 CFR 250.171(b) require lessees to submit letters of acceptance or rejection from the operators of offsetting properties and obtain the Regional Supervisor's approval before commencing production of wells whose completed interval is closer than 500 feet to the lease line. The identification of the subsequent paragraphs in § 250.171 has been changed accordingly.

In a recent State District Court decision in Lafayette, Louisiana, the court found that curtailment of gas production from gas reservoirs producing under a water drive mechanism will result in loss of otherwise recoverable gas reserves if the reservoirs are not produced at the maximum rate consistent with good engineering practice. Although the court found that these types of reservoirs were sensitive to low production rates, the court held that any attempt to calculate the damages caused by the curtailment of production would be too speculative. The proposed definition of "sensitive reservoir" in § 250.170 was not intended to include gas reservoirs similar to those addressed in the aforementioned State court opinion. The definitions of "sensitive reservoir" and "nonsensitive reservoir" in the final rule were revised accordingly. Under the final rule, a reservoir would be classified as sensitive and an MER required for reservoirs when the ultimate recovery of oil and gas would be decreased by high production rates.

Additionally, the following changes were made for clarity and accuracy. The word "released" was changed to "flared or vented" in 30 CFR 250.175(a)(1) to more accurately describe the manner in which vapors may be disposed of from the system as a part of normal operations. In order to address the flaring of gas in gas-lift wells and in other normal pressure venting situations, the word "abnormal" was deleted from § 250.175(a)(2) to enable the lessee to relieve normal system pressure during temporary situations. These changes clarify that limits and records for flaring and venting apply to a facility and that various flaring or venting locations on a facility should not be treated as separate flare or vent points.

A total of 11 commenters submitted comments on the provisions proposed as Subpart K, Production Rates. The comments and responses follow.

Comment—One commenter recommended that the definitions of oil and gas reservoirs and of sensitive and nonsensitive reservoirs in § 250.170 be based on quantifiable performance standards such as gas-oil ratio (GOR) and the percentage of recoverable reserves subject to loss due to inappropriate production rate.

Response—This recommendation was not adopted. Performance standards in the context of these proposed regulations are meant to provide flexibility, not rigidity. Specific limits on the information used to classify reservoirs would be unduly restrictive. The more general definitions found in the final rule allow the use of all available information and the consideration of individual circumstances in classifying reservoirs as sensitive or nonsensitive.

Comment—Two commenters recommended that the word "original" be inserted before the term "associated" in the classification "Oil Reservoir with an Associated Gas Cap" in § 250.170 and 250.171. This revision would avoid potential misclassification of a reservoir in which a secondary gas cap is subsequently created.

Response—This recommendation was not adopted. A reservoir with a gas cap may be sensitive to unduly high rates of recovery regardless of whether the associated gas cap exists when production starts or subsequently develops as dissolved gas comes out of solution in the reservoir. The goal of the MER program is to maximize the ultimate recovery of oil and gas from a reservoir.

Comment—There were several comments concerning the classification

of reservoirs as sensitive or nonsensitive and the practice of requiring MER's on sensitive reservoirs only. Some commenters supported this proposal because it would reduce the MER filing requirements and would adequately prevent waste of oil or gas. One commenter objected to the proposal stating that all reservoirs, regardless of their sensitivity, have maximum rates that should not prudently be exceeded.

Response—The latter comment was not adopted. The MER is intended to prevent waste due to the inefficient, excessive, improper use of or the unnecessary dissipation of reservoir energy. It has been demonstrated that production rates do not adversely affect the ultimate recovery of oil and gas from reservoirs with certain predominant drive mechanisms. Therefore, MER's are not needed for such nonsensitive reservoirs. The MPR program addresses other limitations to well production rates together with the efficient and effective use of reservoir energy.

Comment—There were many comments submitted concerning the MPR requirements. Several commenters proposed deleting all the MPR requirements but retaining the submittal of Form MMS–1868, Well Potential Test Report. One commenter proposed deleting MPR requirements for nonsensitive reservoirs. Their reasoning was that the MPR program has no visible impact on present day operations and very little informational value. They contended that the quarterly oil-well tests and semiannual gas-well tests are sufficient to indicate production rates from each well and that the modified MER program is adequate to determine if there is waste of oil or gas.

Response—These recommendations were not adopted. The MPR program allows MMS to approve or disapprove the operator's proposed maximum rate of production for each well. Such oversight is necessary for the OCS program to assure safe operations and the prevention of waste. Well test information without MPR requirements would not be sufficient for managing OCS operations. The MER program addresses only waste due to the inefficient, excessive, or improper use of or the unnecessary dissipation of reservoir energy. The MPR program is intended to prevent waste by recognizing MER limitations and limitations imposed by well and surface equipment, sand production, GOR and water-oil ratio, location of perforated intervals, and prudent operating practices. Such limitations are present in all wells completed in nonsensitive as well as sensitive reservoirs. The MPR requirements provide for notifying the Regional Supervisor when changes in these limitations warrant changes in the approved MPR.

Comment—Several commenters proposed redesigning the existing MER Form MMS–1866 to include and better describe all the reservoir's parameters for an oil reservoir with an associated gas cap.

Response—This recommendation was recognized as having merit. The current Form MMS–1866 is functional for the reporting of reservoir data for all classifications. However, it could better describe the reservoir parameters for oil reservoirs with an associated gas cap. Form MMS–1866 will be reviewed and appropriate changes proposed.

Comment—There were several recommendations concerning specific MER requirements. First, some commenters suggested that a revised MER be submitted on Form MMS–1866 showing only the required information that has changed in the basic reservoir data. The commenters' position is that there is no need to duplicate the same basic reservoir data in proposing to revise an MER. Second, one commenter recommended that failure to submit Form MMS–1866 with appropriate supporting information should result in immediate reclassification of the reservoir as sensitive for the ensuing 6-month period. Third, one commenter suggested that for reclassification of a reservoir, a similar requirement as that specified in § 250.176(b) (Downhole commingling) should be included requiring notification of all concerned parties that an application is being filed with MMS to reclassify a reservoir. The commenter is concerned that the operator's views are not always the same as those of other partners.

Response—These three recommendations were not adopted. First, MMS's approving official should have correct and current verifying information on the request to authorize and approve. All of the required data are used in verifying that the proposed MER is appropriate. Incomplete applications could lead to significant errors, mishandling of the data, and misclassification of reservoirs. Concerning the second comment, reclassification of a reservoir based upon an absence of information is not appropriate. Other punitive action can be initiated against a lessee for failure to timely submit data and information. The third comment suggests the inclusion in § 250.171(d) of a notification of all concerned parties similar to the requirement in § 250.176(b). Section 250.176(b) concerns a competitive situation in which one operator may have no knowledge of the intentions of the offset competing operator. In § 250.171(d) addressing the case of partners in the same lease, the designated operator acts on behalf of the partners according to such a designation, and differences of opinion among partners are internal matters to be resolved among themselves. The MMS will always consider any evidence submitted by any interested party. Nevertheless, in order to clarify MMS's right to initiate action to change a classification, the first sentence in § 250.171(d) will have the words "by MMS" added following the phrase "may be reclassified." This paragraph is currently designated § 250.171(e).

Comment—There were several recommendations concerning specific MPR requirements. First, in § 250.172(b), several commenters proposed that well tests not be required for shut-in well completions. Second, two commenters recommended that the requirement for submitting well tests within 45 days of the day the test was conducted should be deleted. The commenters felt this would eliminate excessive and unnecessary regulations and reduce the paperwork burdens. Third, one commenter suggested that "first continuous production" as used in this section be defined as "twenty-four (24) hours, excluding the required well test period." Fourth, one commenter suggested that more information should be supplied on the forms submitted for MPR's. The commenter wanted to include all parameters and/or correction factors obtained and/or estimated, sand production, and well and surface equipment capacities. Also, this same commenter requested inclusion of other items of information.

Response—The first recommendation that well tests not be required for shut-in well completion was adopted. The regulation was changed at § 250.172(b)(3) to read "producing oil-well" and "producing gas-well." Concerning the second comment, the 45-day requirement in § 250.172(b)(3) remains unchanged. Current well test data are needed for the OCS program to assure safety of operations and the prevention of waste. Regarding the third comment, setting a fixed hourly limit for continuous production would ignore the nature and complexity of offshore operations. Some wells are flowed for weeks or longer and then temporarily abandoned for a year or more, waiting on a platform, pipeline, production facilities, etc. Other wells can be considered on continuous production after 24 hours. The more general term

allows a case-by-case determination. Last, the inclusion of additional items of information on the forms as suggested by one commenter was not adopted. The information is already required on the forms, is provided to MMS on some other document, or is not needed by MMS on a routine basis. Data such as correction factors or sand volumes may and will be required by MMS on a case-by-case basis when it is determined that the data or information is necessary.

Comment—One commenter asked for an exact definition of "temporary" and "normal variations" as used in § 250.172(c), Temporary rates.

Response—This recommendation was not adopted. The very nature and complexity of all factors affecting the production rates of offshore wells make rigid definitions or guidelines impractical. The fact that MPR's are normally set at 110 percent of the well test automatically provides room for upward variations. In questions of this nature, it is best to leave room in the regulations for a case-by-case evaluation of individual problems and circumstances. An approximate limit for the term "temporary" in § 250.172(c) is established by a reference to provisions in § 250.172(a)(5) which indicates that efforts to balance production should be initiated the month following the month in which over production occurred.

Comment—There were many comments concerning § 250.173, Well production testing. First, several commenters suggested that the requirement concerning the pretest period and recovery of fluids introduced into the formation be clarified. Further, this stipulation should apply only to fluids introduced during completion, recompletion, reworking, or treatment operations. Fluids introduced for storage or enhanced recovery need not be recovered prior to the testing. Second, one commenter disagreed that the well tests must be witnessed by MMS. Third, one commenter suggested that MMS needed to be more strict in the testing requirements. The commenter suggested that any test less than 4 hours duration or with less than 6 hours stabilized flow prior to that test should be unacceptable. Fourth, some commenters expressed concern because the predetermined 6-hour stabilization period applied to all well tests. Fifth, one commenter felt prolonged well tests would often be necessary for wells with a high water cut and/or low gravity. Sixth, some commenters observed that stabilization periods are essentially different for every well and vary from less than 6 hours to more than 6 hours. They contend that the lessee is in the best position to determine a stabilization period for each well and that approval by the Regional Supervisor adds unnecessary paperwork burden to both industry and MMS. Seventh, one commenter recommended a multipoint back-pressure test to determine open flow potential for all new and recompleted gas completions. Eighth, some commenters agreed with using 15.025 pounds per square inch absolute (psia) as a pressure base; however, these commenters noted that the draft version of the MMS Royalty Valuation Procedure proposes a pressure of 14.73 psia.

Response—The first recommendation concerning the recovery of fluids introduced into the formation was adopted, and the regulation was revised. The second comment appears to be based upon a misreading of the proposed rule which stipulated that well tests *may* be witnessed by MMS personnel. The remaining five recommendations in the comments were not adopted. Concerning the third, fourth, fifth, and sixth comments, the stipulated testing requirements have proven effective under the previous regulations. Under the final rule, testing requirements may be modified by the Regional Supervisor for individual wells when the stipulated requirements are determined to be too restrictive or when the test results are found to be unreliable. Regarding the seventh comment, the final rule does not require a multipoint back-pressure test unless requested by the Regional Supervisor since this information is not needed on a routine basis. Last, historically, a pressure base of 15.025 psia and adjustments to that base have been used in the GOM OCS Region. The Pacific OCS Region has used a pressure base of 14.73 psia. A mandatory change in that pressure base would create a substantial administrative burden on the industry to change company production records, company accounting records, and existing gas contracts in the GOM, many of which were negotiated using a pressure base of 15.025 psia with little, if any, demonstrable benefit to the Federal Government from such a change. The final rule calls for the use of a pressure base of 14.73 psia, except in the GOM where a pressure base of 15.025 psia is to be used. Should MMS Royalty Valuation Procedures call for a pressure base of 14.73 psia, a conversion factor can be used in order to convert to that pressure base.

Comment—There were several recommendations concerning § 250.174, Bottomhole pressure survey. First, several commenters recommended inserting the word "static" before "bottomhole pressure surveys" in order to make it clear that lease operators need to submit the results of only static bottomhole pressure surveys and not flowing bottomhole pressure surveys. Second, several commenters recommended adding a sentence stating that waivers to static bottomhole pressure surveys may be approved by the Regional Supervisor if justified by the operator. In some cases, shutting in a well to run a static bottomhole pressure survey may damage the well and ultimate recovery. Third, one commenter proposed that bottomhole pressures be required for all reservoirs and not just those with three or more wells. Fourth, one commenter proposed interference tests in the case of significantly different bottomhole pressures reported in wells which are supposed to be completed in the same reservoir.

Response—The first recommendation was adopted, and the regulations were changed accordingly. The remaining three recommendations were not adopted. Concerning the second recommendation, bottomhole waivers do not need to be provided for in this particular section because approval for departures is authorized in § 250.3(b). Regarding the last two recommendations, bottomhole pressure surveys and interference tests are valuable tools used by reservoir engineers. However, in the interest of reducing the recording and reporting burden on the operator and the amount of paperwork for all concerned, routine bottomhole pressure testing has been limited to reservoirs with three or more well completions. Also, the special difficulties and hazards of the offshore environment, such as deep high pressure wells which are highly deviated, production platforms with densely spaced wellheads, and the difficulties of transportation, make it advisable to limit bottomhole pressure testing operations as much as possible to be consistent with good reservoir management. Section 250.174 provides for obtaining pressure surveys from specific wells upon the request of the Regional Supervisor. The Supervisor's request could include interference tests when deemed necessary.

Comment—There were many comments submitted concerning the requirement in § 250.175(a) that during certain stipulated situations gas shall not be flared for more than 24 hours without the approval of the Regional Supervisor. Several commenters said that 48 hours should be the limit for continuous flaring without approval while one commenter suggested 72

hours. Their position is that a greater time period would allow time for routine compressor maintenance and repairs, well repairs, and drill-stem testing without obtaining special approvals and shutting in oil wells. Paperwork and recordkeeping would also be reduced.

Response—The recommendation to extend the limit to 48 hours was adopted in § 250.175 (a)(2)(i) and (a)(3) with provisions to allow the Regional Supervisor to establish a limit of less than 48 hours when necessary to prevent degradation of the air quality and the language has been revised accordingly. Further, § 250.175 (a)(3) and (a)(4) have been combined.

Comment—Some comments were received concerning the requirement that flaring at a point (from a facility) shall not continue beyond a cumulative time of 144 hours during any calendar month without the approval of the Regional Supervisor. The commenters stated that the requirement should be eliminated because it restricts time for routine compressor maintenance without obtaining special approvals and shutting-in oil wells which results in added recordkeeping.

Response—The recommendation was not adopted. It has been determined that 144 hours of cumulative flaring and venting time from a facility during any calendar month provides sufficient time to perform routine maintenance on compression and related production equipment. This rule is designed to identify repeated short-time flaring and venting instances which can result in extensive cumulative flaring and venting time and large volumes of gas being flared or vented.

Comment—Several comments were submitted concerning the proposed regulation dealing specifically with the flaring and venting of gas-well gas. Those commenters stated that the phrase referring to the alternative course of action of shutting-in gas wells was unnecessary and should be deleted.

Response—The recommendation was adopted and the regulation revised accordingly. Language was added to provide for the extension of flaring and venting of gas on a case-by-case basis with the approval of the Regional Supervisor.

Comment—Several comments were submitted concerning the specific records of flared and vented gas which are to be kept and made available for inspection by MMS's representatives. These records include daily volumes of flared and vented gas, number of hours of flaring or venting on a daily basis, reasons for flaring or venting, and a list of producing wells contributing to the flare or vent along with respective GOR data. Each of the commenters recommended that only minimal records providing daily volumes of flared or vented gas be required to be maintained. They argue that the additional data required in the new regulations are not now available, would require a massive and costly data collection and recordkeeping effort, and represent an increased recordkeeping burden over the present regulations without any resulting benefits.

Response—The recommendation was not adopted. The NTL No. 75-9, dated May 13, 1975, required that records detailing flaring and venting occurrences be available at the platform where the equipment is located for the purpose of monitoring gas flaring and venting. Sections 250.57-1(k) and 250.57-2(g) in the existing rules require the submittal of similar information to MMS in order to effectively monitor emissions and air quality. The detailed recordkeeping requirements in the new rule do not represent an increased data collection burden but only aim to clearly detail the specific information which has been required in the past and which represents the minimum data and records necessary to effectively monitor gas flaring and venting occurrences and approvals. Past experience with most operators and lessees indicates that these kinds of records *have* been kept routinely and can be made readily available to MMS either by telephone or through field inspections.

Comment—There were several comments concerning § 250.177, Enhanced oil and gas recovery operations. One commenter recommended that the requirement to timely initiate enhanced recovery operations be eliminated from § 250.177(a). The commenter stated that a prudent operator will always pursue economic tertiary projects and, therefore, the requirement is not necessary. Another commenter contended that enhanced recovery data must be maintained confidential.

Response—The first recommendation was not adopted. The purpose of the requirement to initiate enhanced recovery operations in § 250.177(a) is to require operators to demonstrate prudence and ensure that operators initiate enhanced recovery operations where such operations would result in an increase in the ultimate recovery of oil and gas from a reservoir using sound engineering and economic principles. Regarding the second comment, the enhanced recovery data submitted to MMS is maintained confidential.

Subpart L—Production Measurement, Surface Commingling, and Security

Subpart L, Production Measurement, Surface Commingling, and Security, includes rules to ensure the accuracy and completeness of measurements used for royalty payment purposes. These rules govern the equipment and procedures to be used to measure the quantity of production leaving a lease or entering a storage tank, the procedures to be used if production from two or more leases is combined prior to measurement for royalty purposes (commingling), and the equipment to be used and procedures to be followed in establishing a site security program.

Subpart L of the final rule replaces current §§ 250.60, Measurement of oil; 250.61, Measurement of gas; and 250.68, Commingling production; and current OCS Order No. 13, Production Measurement and Commingling. The proposed provisions for measurement of sulphur have been moved to proposed Subpart P. The merging and revising of these rules eliminate redundancy, clarify requirements, and address use of new technology.

Comments from 21 interested parties were received concerning this subpart. The majority were from companies engaged in offshore operations or related industries. These included several engineering organizations which, together with operating companies, provided a thorough review of the mechanisms, procedures, and standards prescribed in the proposed rule. There were numerous suggestions for revisions to the proposed rule to improve the operational requirements and, in some cases, the clarity of language. Many of the recommendations were adopted in the final rule. A discussion of comments on individual paragraphs of Subpart L follows.

Comment—One commenter suggested revising the title of Subpart L by adding the word "surface" before the word "commingling" to distinguish Subpart L from § 250.176 of Subpart K which pertains to downhole commingling.

Response—This recommendation has been adopted. The title of Subpart L in the final rule reads "Production Measurement, Surface Commingling, and Security."

Comment—There were two comments concerning all of § 250.180 in general. One commenter remarked that there are significant differences between the rule as proposed and requirements in the API Manual of Petroleum Measurement Standards (MPMS). Another commenter stated that self-interest of the operator will tend to assure proper measurement

and that the use of performance standards would be proper rather than detailed procedures.

Response—These recommendations were not adopted. The MMS recognizes that the API MPMS should be used in conjunction with § 250.180 to ensure accurate measurement. However, items detailed in § 250.180 such as the handling of malfunction meter factors or meter proving frequency have been mentioned in less detail in the MPMS leaving them open to differing interpretations as to proper procedures and methods of operation. As to the supposition that self-interest of the operator assures proper measurement, this may not always be the case. Sales transactions in the OCS are not always arms length agreements. In addition, there have been numerous instances where commingled production from State leases and Federal leases may be "properly measured" from the common lessee's point of view but not from MMS's point of view. Detailed procedures are necessary because royalty measurement points sometime differ from custody transfer points.

Comment—Four commenters suggested two changes to clarify the meaning of § 250.180(a). It was recommended to add the word "surface" before the word "commingling" and the word "liquid" before the word "hydrocarbons."

Response—The recommendation to add the word "liquid" to modify the term "hydrocarbons" has been adopted in order to clarify that this paragraph is under the general section referring to measurements of liquid hydrocarbons. However, there is no need to change the reference to commingling because the general requirements for this are addressed in § 250.182.

Comment—There were two comments on § 250.180(b) concerning application and approval requirements for measurements of liquid hydrocarbons. One commenter suggested that the term "commingling" be replaced with the term "surface commingling." The other expressed uncertainty about the meaning of the term "liquid hydrocarbons" and suggested that a definition of this term be included.

Response—The recommendation to replace the term "commingling" with the term "surface commingling" has not been adopted. That change is not necessary here because the word "surface" has been added to the title of Subpart L. The terms "commingling" and "liquid hydrocarbons" have been defined in this final rule for clarification.

Comment—Two commenters suggested that the title of § 250.180(c) be changed to "Liquid Sales Meter Facility Requirements" from "Sales Meter Facility Requirements" for clarity.

Response—This recommendation was not adopted. The title of § 250.180 is "Measurement of liquid hydrocarbons," and the requirements apply only to liquid metering facilities.

Comment—Four commenters made suggestions for rewording § 250.180(c)(1) which states that a meter upon which royalty is based shall be considered a sales meter. All suggested that a sales meter be described as one that transfers custody and upon which royalty is based because this definition better distinguishes a sales meter from an allocation meter. Two commenters also suggested that the paragraph be reworded to include a requirement that a meter meet the standards of groups such as API, American Gas Association, and Gas Processors Association.

Response—These recommendations were not adopted. Although the vast majority of meter locations that are designated by the MMS as royalty measurement points are also custody transfer points in contracts between sellers and buyers, this is not always the case. A sales meter is one on whose measurements royalty is directly based, while an allocation meter is one that is used to determine the proportion of production to be credited to a lease or leases in a commingling situation. Although the final rule does not distinguish between liquid allocation meters and liquid sales meters, differentiations between allocation and sales meters are addressed on a case-by-case basis during the approval of measurement facilities. Each application concerning liquid measurement facilities must be evaluated and a determination made as to whether the equipment and procedures the operator proposes to use conform to the production measurement equipment and procedures currently approved for other leases and operators within the particular transportation system. There must be a certain degree of flexibility in making determinations as to the liquid sales and royalty measurement point. The MMS does agree that a liquid sales meter should be designed, operated, and maintained within certain industry guidelines and standard practices, but these requirements are addressed in other sections of this subpart.

Comment—There were five comments on § 250.180(c) suggesting the addition of a requirement for temperature compensator systems in sales meter facilities because this would ensure or provide for temperature compensation for the meter reading in the design and installation or operation of sales meter facilities for liquid hydrocarbons.

Response—This recommendation has been adopted to the extent that a new item (iv) has been added to § 250.180(c)(2) to provide for either direct temperature measurement systems or temperature compensation systems to allow existing systems to remain in place without immediate modification.

Comment—There were three comments on § 250.180(c)(2)(i) concerning sales meter facility requirements that suggested the addition of turbine meters and their associated electronic equipment. The rationale for these comments stated that turbine meters are utilized extensively in the Gulf of Mexico OCS for surface commingling measurement.

Response—It is recognized that turbine meters are currently in extensive use in the GOM to measure liquids but not for sales purposes. The subject of § 250.180(c) is sales meter facility requirements not allocation meter facility requirements. Since the final rule provides for use of an "other meter" with approval of the Regional Supervisor, the use of turbine meters can be approved under this provision when appropriate. The suitability of a particular measurement device for a given location can be addressed on a case-by-case basis with attention given to the applicability of established industry standards and practices.

Comment—Five commenters suggested two changes to § 250.180(c)(2)(ii) concerning the requirement for meter proving equipment. Three suggested that the paragraph be deleted because proving requirements are covered elsewhere in paragraph (d), and proving equipment is not always part of the onsite facility. Two commenters suggested revision of the paragraph to include a portable master meter among the types of equipment specified for meter proving.

Response—The recommendation to delete § 250.180(c)(2)(ii) has not been adopted. This provision establishes the basic requirement that there must be a provision for meter calibration. In contrast, paragraph (d) contains requirements for proving conducted with various types of equipment. Although the vast majority of sales meter facilities have prover equipment as part of the facility, the paragraph does not state that it must be one of the permanent components. The text of the final rule has been modified to specify that required meter proving devices may be permanently installed or portable.

Comment—There were five comments on § 250.180(c)(2)(iii) concerning the type of sampling device to be used with

the sales meter facility. Four commenters suggested that the word "counter" be deleted after the word "meter" in describing the device used to pulse the sampler system. One commenter observed that a proportional-to-flow "isokinetic" type sampling device will give the most accurate sample.

Response—The recommendation to delete the word "counter" has been adopted and the word "output" substituted for it. This reference in the proposed rules to the meter "counter" meant the device that makes a pulsed output in response to the turning meter assembly not the meter counter register. Other devices may be used to pulse the sampler system but they must be closely reviewed prior to approval since the use of a timed sampling device, for example, would greatly affect the location of the sample point with respect to the meter and diverter if so equipped.

With respect to the comment about "isokinetic" types of sampling devices, there seems to be no reason to further specify the type of proportional-to-flow sampling device. The API MPMS, Chapter 8—Sampling, covers recommended practice for sampling methods used to obtain representative samples of petroleum and petroleum products. Although the document addresses many considerations for obtaining accurate samples including sampling frequency, probe location, probe design, and design of automatic oil sampling systems, there is no mention of "isokinetic" samplers. The specific sampling system to be used at a particular liquid measurement station is approved on a case-by-case basis by the Regional Supervisor. The applicability and ability of a sampler to obtain representative samples are reviewed at the time of approval. If the word "isokinetic" in this comment refers to a static mixer, then it is an acceptable device for the inducement of turbulent flow.

Comment—Four commenters suggested several revisions to § 250.180(c)(3) which concerns the design and installation of sales meters for liquid hydrocarbons. The proposed paragraph (c)(3) contained five separate provisions designated (i) through (v). Three of the commenters suggested rewording the heading in paragraph (c)(3) to state that sales meters shall be "designed and operated to accomplish" the requirements specified in (i) through (v), rather than the proposed wording which stipulated that sales meters shall be "designed and installed to include" the listed requirements. One commenter suggested the addition of a provision for the measurement of temperature or direct compensation of the liquid hydrocarbon measurement for change in temperature. Changes were also suggested to items (iv) and (v). In the proposed rule, provision (iv) required that all meters be operated within the gravity range specified by the manufacturer. The commenter suggested that this provision be modified by the additional requirement that the operation of meters be within 10 percent of the pressure and flow rate at which they were approved. The suggestion on provision (v) was that it be changed to reflect that the pressure and flow rate through each meter be maintained within manufacturer's maximum and minimum specifications recommended for accurate measurement.

Response—The suggestion to change the wording of § 250.180(c)(3) to specify that the design of sales meters "accomplish" certain requirements is an improvement in clarity and is a more appropriate expression of MMS's objective in the case of provisions (i) through (iii). This wording has been adopted. However it is a cumbersome heading for provisions (iv) and (v). In view of this and specific comments discussed below pertaining to provisions (iv) and (v), § 250.180(c)(3) has been revised in the final rule by dividing it so that § 250.180(c)(3) contains the language suggested for the heading, and a new § 250.180(c)(4) contains the performance standards to be achieved by maintenance of meter facilities. Subsequent paragraphs have been renumbered as appropriate.

Section 250.180(c)(3) of the final rule contains provisions (i) through (iii) substantially as these appeared in the proposed rule and a new provision (iv) which is an added requirement. Section 250.180(c)(4) contains three provisions, (i) through (iii). The first provision, (i), was previously designated § 250.180(c)(3)(iv) in the proposed rule. Section 250.180(c)(4)(ii) in the final rule is a revision of § 250.180(c)(3)(v) of the proposed rule, reflecting the recommendation that a meter be operated within the manufacturer's specifications for minimum and maximum flow rate for linear accuracy. Section 250.180(c)(4)(iii) was added in response to one of the comments received on § 250.180(c)(3)(iv) of the proposed rule. The final rule contains a new requirement at § 250.180(c)(4)(iii), which addresses the need to reprove meters when changes in conditions such as pressure, temperature, density, viscosity, and flow rate may result in inaccurate readings.

The recommendation that a provision be added for the measurement of temperature or direct compensation of the liquid hydrocarbon measurement for change in temperature was also adopted. This provision is more appropriate in § 250.180(c)(2), and the requirement has been added there as item (iv).

Comment—Four commenters made two suggestions about proposed § 250.180(c)(4)(i) concerning sampling devices. One commenter stated that the sampling point should be downstream of the divert valve. The other commenter stated that it should be located in accordance with accepted industry practice or the API MPMS, Section 8.2.

Response—The sample point can be upstream of the divert valve because if the sampler is pulsed by the meter itself, then the meter would not be turning and no samples could be taken during the diversion of the bad oil upstream of the meter. Therefore, the first comment has not been adopted. The recommendation that the sampling of oil during sales and royalty measurements conform to industry standards was adopted. Proposed § 250.180(c)(6) was revised to cite API MPMS, Chapter 8—Sampling, and redesignated as § 250.180(c)(5).

Comment—Three commenters suggested five changes to proposed § 250.180(c)(4)(iii) concerning the location of the sample probe in the installation of sampling devices. (This is renumbered (c)(5)(iii) in the final rule.) One commenter stated that the sample probe should not be limited to a vertical run of piping since sufficient mixing can be obtained with the use of devices to induce turbulent flow (mixers).

Response—This recommendation was not adopted. This use of devices to induce turbulent flow is not common enough to make their use a requirement.

Comment—Another commenter suggested the deletion of the phrase "where a region of turbulent flow exits," stating that it implies that if Reynolds Number is less than 2000, it is acceptable to install the sample probe immediately adjacent to a pipe fitting.

Response—This suggestion was not adopted. The final rule has been modified to state that the sample probe is to be located within a region of turbulent flow. The sample probe must also be at least three pipe diameters distant from a pipe fitting.

Comment—A third commenter suggested the addition of further requirements that the probe be installed downstream of any divert valve, that the three pipe diameters requirement apply to installations after the effective date of the regulations, and that the Reynolds

Number value of 2000 be stated to define a turbulent region.

Response—This recommendation was not adopted. It is not necessary for a sample probe to be installed downstream of any divert valve to prevent excessive sampling of water provided the divert valve is upstream of the meter and the sampler is being pulsed by the meter itself. No high water content oil would be sampled if the meter is not turning. This topic is further addressed in comments on § 250.180(c)(4)(i). Since it is common industry practice to locate the sample probe more than three pipe diameters from any fitting, as suggested in the API MPMS, Chapter 8, the regulation will be enforced as of the effective date of the rule. Finally, there is no reason to specify the Reynolds Number of 2000 to define turbulent flow.

Comment—There were three identical comments concerning proposed § 250.180(c)(5) requiring the Regional Supervisor's approval of equipment. Each recommended that it be deleted on the basis that it is redundant with paragraph (b).

Response—The recommendation has been adopted and § 250.180(c)(5) has been deleted from the final rule. At the same time, § 250.180(b) has been revised to clarify that the application must be submitted to the Regional Supervisor for approval and contain information sufficient to demonstrate that the requirements of this section will be met.

Comment—There were 19 comments by 8 commenters concerning § 250.180(c)(6) pertaining to the documents incorporated by reference for the purpose of establishing standards for procedures to obtain net volume and other measurements. One commenter suggested changing the term "net volume" to "net standard volume." There were five comments suggesting the deletion of provision (i) of paragraph (c)(6) referencing API 2543, American Standards Method of Measurement of Petroleum Liquid Hydrocarbons by Positive Displacement Meter, because these documents are no longer in print. They were replaced subsequent to the issuance of the proposed regulations by new chapters of the API MPMS.

Response—The recommendation to revise § 250.180(c)(6) to reflect references to current documents was adopted. References to obsolete documents have been removed, and several new references to chapters in the API MPMS have been added. Some of these specific additional references were also suggested in other comments to Subpart A which compiles all documents incorporated by reference in all of the subparts of Part 250.

Comment—There were two identical comments submitted concerning § 250.180(c)(7) which is a requirement that sales meter facilities shall be appropriately located as approved by the Regional Supervisor. The comments suggested that this paragraph be deleted since a duplicate requirement is found in paragraph (d).

Response—This recommendation has not been adopted. While it is true that § 250.180(d) concerns sales meter facilities, it pertains to proving requirements for meters not to the location of meters. However, upon considering the issue of the most appropriate location for this requirement, it was decided that the requirement falls within the scope of § 250.180(b), Application and approval. Therefore, § 250.180(c)(7) has been deleted in the final rule, and the requirement found there in the proposed rule has been incorporated into § 250.180(b) of the final rule.

Comment—There was one comment concerning § 250.180(d)(3). It suggested the referencing of API MPMS, Chapter 4—Proving Systems.

Response—This recommendation has been adopted. Section 250.180(c)(6) of the final rule incorporates API MPMS, Chapter 4 by reference.

Comment—There were six commenters who submitted recommendations on § 250.180(d)(3)(i) concerning the calibration of master meters. Three of the commenters recommended that master meters be calibrated using not only similar gravity fluid but also fluid of similar viscosity and temperature. Two commenters recommended use of fluids other than crude but having similar physical properties. Three other commenters suggested changing the requirement for frequency of calibration from "within 42 days" to "within 45 days" since 45 days is used for gas meters. One commenter recommended adding the phrase "at the required flow rate" to assure calibration at or near the test flow rate.

Response—These recommendations were adopted in part, and the second sentence in § 250.180(d)(3)(i) was changed to provide that the master meter be calibrated with a fluid of similar gravity, viscosity, and temperature as flows through the operating meter and with a similar flow rate monthly but that the period between calibration is not to exceed 6 weeks unless a longer period is approved by the Regional Supervisor. Master meters should be calibrated under conditions that are as close to producing conditions as possible. Sometimes this may be difficult because the same master meter is often used to calibrate meters at more than one location, and the physical properties may change from location to location. To achieve the desired results, the conditions at the various locations should approximate the properties of fluids used in calibrating the master meter. As long as the fluids are of similar gravity, temperature, and viscosity as the fluids available during normal operating conditions, other fluids may be used to calibrate the master meter. There is no "42-day" requirement. The requirement is that meters be proven each month. However, up to 42 days (6 weeks) may elapse between provings. This provides leeway so that the provings do not have to occur on the same day each month. The "45 days" for gas meters cannot be compared to the liquid meter monthly requirement. Gas meters do not have to be calibrated monthly but rather at least once every 45 days. The addition of the phrase "at the required flow rate," is considered to be unnecessary. The flow rate requirements are covered by manufacturer's specifications.

Comment—Three commenters on § 250.180(d)(3)(ii) suggested revising the first sentence of the subject paragraph to add a phrase to clarify that the provision refers to the difference in the meter factors between the runs.

Response—This recommendation has been adopted.

Comment—Three commenters on § 250.180(d)(3)(iii) recommended revising the paragraph to provide that the "master meter may be installed either upstream or downstream of the operating meter, but shall be upstream of any back-pressure or reverse flow check valves associated with the operating meter."

Response—This recommendation has been adopted, and § 250.180(d)(3)(iii) has been revised accordingly.

Comment—There were two comments on § 250.180(d)(3)(iv) concerning calibration of mechanical-displacement provers. The first comment recommends that mechanical provers be calibrated after the first year of operation and then every 5 years. The second comment recommends that MMS not require calibration of provers every 5 years but rather a visual inspection every 2 years.

Response—These comments are diametrically opposed to each other. The first one recommends more stringent requirements, and the second one recommends less stringent requirements. The MMS believes that these provers should be calibrated every 5 years. This requirement would not only provide for calibration every 5 years but would also mean a visual

inspection of the prover sphere and the internal coating at least every 5 years. The MMS's position is based on measurement experiences, discussions with measurement experts, and widespread industry practice. Therefore, § 250.180(d)(3)(iv) has been revised to require that mechanical-displacement provers be calibrated as least every 5 years in accordance with the API MPMS, Chapters 4 and 11.2.3.

Comment—There were four comments concerning the provisions in § 250.180(d)(3)(v)(C). One comment recommended revising the phrase "The change in tank shell dimension with the change in temperature (Cts)" to "The change in prover volume due to the change in temperature (Cts)." The other three comments recommend deleting the last sentence of paragraph (3)(v)(C) concerning the use of a combined correction factor of Cts and Cts.

Response—These recommendations have been adopted. The last sentence of the proposed paragraph was deleted because API has not published the tables referred to in the sentence and API Standard 2541 has been withdrawn.

Comment—There were six identical comments concerning § 250.180(d)(3)(v)(D) regarding the reference to API Standard 1101, Appendix B, Table II which was proposed to be used in calculating the change in volume of the test liquid with the change in pressure (Cpl). This document is no longer in print.

Response—The final rule removes reference to API Standard 1101 and substitutes a reference to Chapters 11.2.1 and 11.2.2 of the API MPMS.

Comment—There were three comments on § 250.180(d)(4) concerning the requirement for frequency of sales meter proving. One suggested changing the phrase "not to exceed 42 days" to "not to exceed 45 days." In addition, two comments suggested changing the monthly meter proving requirement to quarterly for meters registering less than 7800 bbl/month. The reasons given for these comments were to make liquid meter proving frequency consistent with gas meter calibration frequency and to remove an unnecessary burden on the lessee by allowing low volume meters to be proved quarterly.

Response—These recommendations were not adopted. It would not be appropriate to make these revisions simply to bring the frequency requirements for proving liquid meters in line with those for gas meter calibration because the two types of metering cannot be equated in this manner. For gas orifice meters, the chart recorder is tested for accuracy at various pressure values. For liquid meters, the meter itself is proved for accurate measurement of a known volume. The MMS believes the appropriate frequency for proving liquid meters should be once each month with no more than 6 weeks (42 days) between provings. The previous requirement was for submission of the results of meter proving for a meter measuring liquid hydrocarbons monthly but within 15 days of the prover test. Some operators may have interpreted this to mean every 45 days. This could result in proving the meter 8 times a year rather than 12 times a year. The 42-day period was proposed to give the operators a 2-week grace period to be in compliance if for some reason, such as weather, personnel, or mechanical problems, the scheduled monthly proving had to be delayed. We understand that meter provings for gas and liquid meters are more often than not scheduled by the product buyer or transporter. However, in the case of liquid hydrocarbon sales, companies sell to themselves much more often than in the case of gas sales and therefore can schedule the provings to be in compliance. The suggestion that the frequency of meter proving be quarterly for meters registering less than 7800 bbl/month may have merit under given circumstances. Relief from the monthly requirement may be obtained on a case-by-case basis when warranted.

Comment—There were three comments concerning establishing an operating meter factor in § 250.180(d)(4)(ii). Two comments concerning the first sentence suggested revising the requirement for proof run results to require that the difference in the meter factors between runs is not greater than 0.0005 rather than the proposed requirement that the difference between results is not greater than 0.0005. The third commenter stated that existing GOM OCS Order No. 13 requires a tolerance of 0.0002.

Response—The recommendation that the first sentence of § 250.180(d)(4)(ii) be revised to establish that it is the meter factor for three consecutive runs that must be compared and be within tolerance was adopted and the sentence revised accordingly in the final rule.

The third comment concerning existing OCS Order No. 13 is in error. Section 2.C.(3)(b) of OCS Order No. 13 was vague as to whether the tolerance 0.0002 applied to runs proving a master meter or proving a meter with a master meter. It was clarified by GOM NTL No. 79-10 to mean the tolerance for proving a master meter. This is corrected in proposed § 250.180(d)(3)(ii).

Comment—There were three comments concerning proof runs to establish a meter factor for a mechanical displacement prover as required in § 250.180(d)(4)(iii). They all suggested revising the first sentence to remove the requirement that the difference between results in proof runs not be greater than 0.0005. The comments all suggested substituting a requirement that the results of proof runs be such that the difference in the meter factor is not greater than 0.0005.

Response—These recommendations were not adopted. It is not standard procedure to calculate individual meter factors for each run with a mechanical displacement prover. It is standard procedure to compare the results of the high speed pulse generator from consecutive runs for the tolerance of 0.0005.

Comment—There were six comments on § 250.180(d)(5) concerning the submittal of meter proving reports to the Regional Supervisor. Three comments suggested deleting the requirement. Two comments suggested changing the submittal period from 10 to 15 days, and one suggested changing it from 10 to 30 days. Five of the six comments recommended maintaining files of meter proving reports in field offices for 1 or 2 years.

Response—These recommendations have not been adopted. However, § 250.180(d)(5) of the final rule has been revised to require the submittal of meter proving reports monthly within 15 days following the end of the month. These operator-submitted documents are kept on file in the Regional Offices and ensure lessee compliance with § 250.180(d)(4). The proposed § 250.180(d) restated the requirements contained in the current GOM OCS Order No. 13. These are not added requirements and do not suggest that meter proving reports, run tickets, and prover calibration documents should be submitted to MMS District Offices.

Comment—There were suggestions from five commenters for various additions and changes to § 250.180(d)(5)(i). This paragraph establishes the deviation level at which a meter factor is considered a malfunction factor and prescribes appropriate procedures to address a malfunction situation including the method to determine the appropriate production measurement during a period of malfunction.

Two comments suggested changing the first sentence to read:

> A meter factor is considered a malfunction factor when the deviation between the factor and the previous factor exceeds 0.0025, unless other known conditions exist that would account for the factor difference.

This would add to the proposed sentence the phrase "unless other known conditions exist that would account for the factor difference."

Three sets of comments suggested revising the second sentence by adding the phrase "checked for damage or wear" after the phrase "removed from service" in prescribing procedures to be undertaken in the event of a malfunction.

Another commenter addressed generally the provisions of both the first and second sentences. These comments suggest that since there may be other causes for a malfunction meter factor, such as changes in flow conditions and fluid properties, these should be investigated prior to removing a meter from service. Further, if any of these possible causes are discovered and are corrected, then the meter should be reproved. Only if the meter shows results of excessive factor deviation after the second proving would it be removed from service and repaired.

There were three sets of comments that suggested inserting the following language for clarification between the second and third sentences.

> If the date of the malfunction can be determined, the previous factor shall be applied to the production measured through the meter to that date, and the malfunction factor shall be applied to the time the malfunction factor was established. If the date of the malfunction cannot be determined, the arithmetic average * * *

Another commenter suggested adding the phrase "unless the date the malfunction occurred can be determined" to the third sentence which concerns averaging of previous and current malfunction factors.

Response—The recommendation to add the phrase "unless other known conditions exist that would account for the factor difference" was not adopted. It is recognized that a deviation greater than 0.0025 between successive meter factors can be caused by problems other than those involving the meter or its associated components. However, the addition of the suggested phrase would mean that if other known conditions cause the deviation, then the current factor would not be considered a malfunction, thus eliminating the basis for factor averaging. The term "malfunction factor" should not be confused with a malfunctioning meter although this is usually the cause of a malfunction factor. A malfunction factor results when the difference between the meter's previous and present capability to accurately measure a known volume of fluid exceeds a certain value (0.0025).

The recommendation that the rule be revised to specify "checked for damage or wear" after the reference to "removed from service" has been adopted. This change was made because the proposed language presumed that this step would necessarily follow removal from service.

The recommendation that a malfunctioning meter not be removed from service until investigated to discover possible causes, or the meter has been reproved but excessive deviation continues has not been adopted. It is not appropriate for a meter with a malfunction factor to be left in service until it can be determined if the malfunction factor can be explained. Although not specifically required by § 250.180, this situation is one where a standby meter would normally be put into service.

The recommendation of alternate approaches to the application of the arithmetic average of the malfunction factor and the previous factor to determine production measurement in the event of a malfunction was not adopted. The method proposed in the regulations is a better way to obtain a representative meter factor over a run period when a malfunction factor has occurred. The method proposed by the comments would require specific procedures and standards to determine the point in time when the malfunction occurred.

Comment—Two commenters each submitted the same two comments concerning § 250.180(d)(6). The first commenter suggested changing the term "(standard conditions are 0 psig and 60 °F)" to "(standard conditions are 14.73 psia and 60 °F)."

Both commenters also suggested that the following be added, "Alternatively the observed API gravity and temperature of the hydrometer may be reported on the run ticket when the calculations are performed separately."

The reason presented for this suggestion states that run tickets should report observed data as a minimum and permit calculations with remote computers to reduce errors.

Response—These recommendations were not adopted. Regarding the first comment, MMS sees no reason to confuse the issue by defining atmospheric pressure by specifying an absolute pressure value. Standard conditions for pressure means atmospheric pressure or 0 psig. The API MPMS Chapter 12, Section 2, Calculation of Liquid Petroleum Quantities Measured by Turbine on Displacement Meters defines standard conditions as 60 °F and atmospheric (0 psig) with a qualification concerning liquids with an equilibrium pressure above 0 psig. However, in the definition of equilibrium pressure it is defined to be zero for liquids with an equilibrium vapor pressure less than 14.73 psia. Since, for these purposes, they are the same, 0 psig should be used. The third sentence of this paragraph states "The Ctl factors shall be listed on the appropriate run ticket when the meter is not automatically temperature compensated."

It is not clear exactly what the second commenters meant by the suggested addition. It is agreed that run tickets should report observed data but a run ticket should also include the net standard volume as calculated from the observed data. The recording of observed gravity and temperature of the volume-weighted sample cannot possibly substitute for the change in temperature (Ctl) factor, although these hydrometer readings along with the volume-weighted average temperature are used to determine the Ctl factor. All factors including basic sediment and water (BS&W) measurements that are used to obtain net standard volume should be shown on the run ticket. Therefore, the addition of this sentence especially the way it is worded would be wrong. It is not necessary that the net standard volume calculations be done in the field, but eventually all factors and calculations should be shown on the ticket.

Comment—There were five sets of comments concerning § 250.180(d)(7) which deals with pulling run tickets and sending them to the Regional Supervisor. Two commenters suggested that the requirement to submit run tickets to the Regional Supervisor be deleted and that tickets simply be kept on file in the company field offices for a period of 2 years. The rationale for this suggestion by two commenters was that the proposed rule would add a "mind-boggling" amount of paperwork to the MMS District Offices and that the suggested change would reduce paperwork.

The other three sets of comments suggested the submittal of copies of run tickets rather than the original.

Reponse—The recommendation to delete the requirement for submitting run tickets was not adopted. The review of run tickets is handled in the regional offices not the district offices and is not an added requirement. The MMS recognizes that deleting this requirement would reduce paperwork. However, it would also impede MMS from ensuring that lessees and operators are operating metering facilities and calculating sales volumes in a manner compliant with § 250.180.

The recommendation to permit the submission of copies rather than original

run tickets has been adopted and § 250.180(d)(7) revised accordingly. Respondents' comments brought to our attention a problem that was not considered in the drafting of the proposed rules. The comment suggested possible misunderstanding of the information to be shown on run tickets. It has been decided to expand the text of the final rule to reduce the opportunity for misunderstanding. The recording of only observed data on run tickets may defeat their purpose. The buyer and seller must reach some understanding on the use of observed data to calculate net standard volume. The MMS is concerned that the run tickets clearly show the gross volume registered by the meter (opening and closing), the current meter factor, correction factors for temperature and pressure if necessary, correction for BS&W content, and observed gravity and temperature from the shake-out, gravity at standard conditions, the operator and location names, dates and times of opening and closing readings, and the net standard volume which forms the basis for royalty due from lessees for the leases having liquid hydrocarbons being measured at the location. In the final rule, the information required to be shown on the run ticket has been described more fully. In addition, to alleviate some burden, the 10-day submittal requirement has been changed to monthly.

Comment—There were five commenters on § 250.180(e)(1) concerning allocation meter facilities. Three commenters recommend that MMS should not require a device capable of proving these meters but rather provide for use of a device because of the availability of portable equipment. These same commenters and another commenter also recommend that either continuous or periodic sampling be allowed instead of only continuous samplings. One commenter suggested defining an allocation meter as "one at which custody does not transfer but is the basis for royalty determination." Another commenter recommended a definition for continuous sampling.

Response—The recommendation that the regulation permit the use of a portable device capable of proving the meter was adopted. The recommendation to replace the "continuous sampling" with a "continuous" or "periodic" sampling requirement was also adopted, however, the "periodic" sampling will be at a minimum daily sampling. Section 250.180(e)(1) was revised in the final rule to incorporate the adopted recommendations including the recommendation to define the term "allocation meter."

Comment—Three commenters suggested revisions to proposed § 250.180 (e)(2) concerning allocation meters. All suggested deleting the provision in both § 250.180(e)(2)(i) and (e)(2)(ii) requiring that allocation meters meet the same proving and tolerance requirements as sales meters. It was suggested that the revision be accomplished by deleting the last part of the first sentence in both § 250.180 (e)(2)(i) and (e)(2)(ii) beginning with the phrase "in accordance with." The reason given for this suggestion was that it is not necessary for allocation meters to have the same level of accuracy as sales meters, and the cost and difficulty of bringing allocation meters to the same proving and tolerance criteria is unjustified.

Response—The recommendation to delete the requirement that meter proving for allocation meters meet the same proving and tolerance standards as sale meters was adopted, and § 250.180 (e)(2)(i) and (e)(2)(ii) were revised accordingly.

Comment—It was suggested that a third provision be added to § 250.180(e)(2) to exclude allocation meters of facilities or wells having the same ownership and royalty interest from the meter proving requirements of this paragraph because precise metering is not necessary in this circumstance.

Response—This suggestion was not adopted. There is no need for a different standard for allocation meters for facilities or wells having the same ownership and royalty interest.

Comment—There were four comments on § 250.180(e)(3) recommending that the requirement for 6-year retention of allocation meter proving reports be changed. Three of the comments recommend a 1-year retention, and one comment recommended a 2-year retention.

Response—The recommendation to reduce the 6-year retention period for meter proving reports for allocation meters has been adopted. A reduced retention period of 2 years is contained in the final rule.

Comment—One comment recommended that § 250.180(f)(2)(i) be deleted because this standard is not part of API MPMS, Chapter 7. Three comments suggested adding Chapter 7 of the API MPMS to the list of other API Chapters referenced in § 250.180(f)(2)(ii).

Response—These recommendations have been adopted. Section 250.180(f)(2)(i) was deleted, and Chapter 7 was added to the list of other Chapters of the API MPMS which were listed in § 250.180(f)(2)(ii) in the proposed regulations. Because of the deletion of § 250.180(f)(2)(i), the individual provisions of proposed § 250.180(f)(2)(ii) designated as items (A) through (F) have been redesignated in the final rule as items § 250.180(f)(2) (i) through (vii).

Comment—There were four comments submitted on § 250.180(f)(3) concerning run tickets from tank measurement determinations. Three of the comments recommended that copies of the run tickets and not the originals should be submitted monthly, instead of within 10 days of being written. The fourth comment recommended that these run tickets should be kept at the field office for a period of 2 years. The comments state that run-ticket tabulations for tanks are done monthly, and the requirement as proposed would mean unnecessary expenses to the operators.

Response—The recommendations were adopted to the degree that copies of run tickets are to be submitted monthly with submission to be within 15 days of the run ticket being written.

Comment—There were several general comments concerning § 250.281, Measurement of gas. One of the comments addressed the subject of working-interest owner's self-interest in dictating performance standards. Two other comments concerned the questions of whether only orifice and turbine meters are acceptable and whether mass measurement is to be permitted. Another comment suggested that there are significant differences between § 250.181 as proposed and the API MPMS, Chapter 14.

Response—No changes were made in the proposed rule on the basis of these commments. The subject of working-interest owners' influencing the development of performance standards to serve their own interests was addressed in the general comments for § 250.180. It has been concluded that MMS requirements used together with industry performance standards provide the most viable set of rules to be followed in assuring the accurate measurement of hydrocarbons on the OCS.

Regarding the comment concerning alternative methods of gas measurement, MMS is unaware of any methods of sales gas measurement in the OCS other than turbine meters and orifice meters. However, § 250.181(c) states that applications shall contain information sufficient to demonstrate that the method of gas measurement proposed meets the requirements in § 250.181. It is conceivable that mass measurement could be approved if an

applicant demonstrated that approach would provide an accurate measurement.

Finally, MMS is unaware of any major conflicts between the proposed rules and the API Standard cited in the last comment. Many provisions of the proposed rule references API's MPMS, some in greater detail and some in lesser detail.

Comment—There were four comments on proposed § 250.181(c)(1) which required that measuring equipment be installed and operated in accordance with recommendations in the API MPMS, Chapter 14. One comment recommended that gas orifice meter charts be used as backup when electronic gas flow measurement equipment is used for measurement purposes.

Another comment proposed that this paragraph specifically cite all the documents pertaining to meter standards of the American Gas Association (AGA) and ANSI which are the same as the current API MPMS Chapter 14 and are referenced in that document. The rationale for separately citing AGA and ANSI documents was to assure continued consistency between API Standards and those of the other groups in view of the possibility that API might soon revise MPMS Chapter 14 to change the current flow equation utilizing new data. The commenter observed that a revised API Standard might not be adopted by AGA or ANSI and suggested that the citation of AGA and ANSI Standards in the MMS rule would ensure that the API Standards in Chapter 14 would not be changed without AGA approval.

Two comments suggested incorporating ASME Standards into the proposed regulations. One comment offered a substitute for API MPMS Chapter 14. The recommended document, ASME Standard MCF-3M-1985, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi was claimed to give more accurate results than the API/ANSI 2530 document referenced in the subject section. The other comment requested incorporation of several other ANSI/ASME Standards addressing gas measurement by turbine meters, transit time ultrasonic meters, calculation of reported uncertainties in fluid flow in pipes, and a glossary of terms. The comment also cited several documents on these subjects which are in preparation.

Response—The recommendations have not been adopted. The recommendation for use of gas orifice meter charts as backup for electronic gas measurement equipment will be given full consideration on a case-by-case basis in the approval process required by § 250.180(c) of this subpart. In the event API Chapter 14 is revised, that revision will not be required by these regulations. A new rulemaking would be required. The AGA could point out any objectionable features of a revised Chapter 14 at that time.

On September 18, 1986, the ANSI Board of Review refused to replace the API 2530 Standard in favor of the ASME Standard MCF-3M-1985. The ANSI/API 2530 document also known as AGA Committee Report No. 3 is the cited standard in most gas sales contracts.

The incorporation by references to several additional ANSI/ASME standards for a variety of meters is not justified since few, if any, of these meters are actually in use on the OCS. Currently, there are two types of gas sales meters in use on the OCS—orifice and turbine meters. Of approximately 1,800 gas meters, less than 5 percent are turbine. Approval by Regional Supervisors for use of turbine or other meters may be sought in accordance with § 250.180(c). Applications and approvals and alternative standards, may be approved if shown to result in an acceptable degee of accuracy.

Comment—There were two comments on § 250.181(c)(2) concerning base pressure for gas measurement. Both suggested changing the base pressure for gas volume calculations for the GOM OCS Region from 15.025 pounds psia to 14.73 psia. The reason for the suggestion is that base data for calculation of gas volumes and existing standards are referenced to 14.73 psia and that all other Regions within MMS, except the GOM OCS Region, use this pressure base.

Response—These recommendations were not adopted. It is recognized that the base pressures designated for use in the regulations are not used by all operators in the GOM or Pacific OCS Regions. However, the 15.025 psia pressure base has been historically used in the GOM OCS Region, and prominent industry trade associations support the retention of the 15.025 psia pressure base in Subpart K, § 250.173, Well production testing. These comments recommended retaining the 15.025 psia pressure base. In addition, 30 CFR 252.152, Standards for Reporting and Paying Royalties on Gas, conforms to § 250.181(c)(2) as proposed. Therefore, to avoid the unnecessary paperwork that a change in the regulation would cause and to maintain conformity with other regulations, this provision is retained unchanged.

Comment—There were three comments of the same nature on § 250.181(c)(3)(ii) concerning calibration equipment. All comments recommend that the entire paragraph be deleted because it is redundant.

Response—The MMS believes that the paragraph should be kept. This paragraph refers specifically to the equipment used to calibrate the meters; § 250.181(c)(1) refers to the royalty meter or measuring equipment. This paragraph assures that not only the meters but also the equipment used to calibrate the meters should be in accordance with standards.

Comment—There were 7 commenters who sent in 12 comments on § 250.181(c)(3)(iii) concerning the requirements for calibration interval, flow rate, and retention of calibration results. Three comments recommended that allocation gas meters should not be calibrated as frequently as sales meters. Three other comments stated that the 6-year retention period is too long and recommended 1-year and 2-year retention periods, respectively. Six commenters questioned the flow rate requirement during calibration. All seven commenters recommended that the term "the average hourly rate" for calibration should be deleted or reworded.

Response—The recommendation that allocation gas meters be calibrated at intervals longer than 45 days was not adopted. Most of the gas meters on the OCS are sales meters so there are relatively few gas allocation meters. Since allocation meters are used in the allocation of gas sold back to the source lessees, which have different ownerships and royalty rates, they should be calibrated.

The recommendation for a shorter retention period for calibration reports was adopted. The reason for requiring retention of these reports at field locations is to enable inspectors to spot-check the reports. The final rule calls for the retention of calibration test data at the field location for a period of 2 years.

The recommendation to revise the wording concerning the average hourly rate was adopted, and § 250.181(c)(3)(iii) was revised to provide that, for orifice meter calibrations, the differential range and static range shall be consistent with the hourly flow rate.

Comment—Three commenters submitted two comments on § 250.181(c)(3)(v). One comment suggested the deletion of the words "the meter" in the phrase "During calibration, if *the meter* readings." This was suggested for greater consistency with § 250.181(c)(3)(iii). One comment stated that this paragraph is poorly worded and may be misinterpreted to mean that

the average volume from the period prior to the last calibration check should be used if the meter is found to be out of specification.

Response—This recommendation to delete the word was adopted.

Comment—Four comments were submitted concerning commingling requirements in § 250.182. Three recommended that the term "surface commingling" replace the term "commingling" everywhere that "commingling" appears in § 250.182. One comment stated that "self-interest of the working interest owners will prevail here."

Response—The recommendation to substitute the term "surface commingling" in the title of Subpart L was adopted. The title of Subpart L and in the heading of § 250.182 has been revised in the final rule. We do not think it is necessary to change the term "commingling" to "surface commingling" throughout the body of the rule since it is understood to apply in view of the headings.

The comment regarding the self-interest of working-interest owners prevailing was too general to permit a meaningful response.

Comment—Four commenters submitted seven comments recommending changes in § 250.182(c) concerning well tests. Three of the comments recommended that the requirement for testing wells once every 2 months be changed to the same requirements as proposed in § 250.172(b)(3) which contains the requirements for determining the Maximum Production Rates based on quarterly tests for oil wells and semiannual tests for gas wells. The four other comments recommend changing the 6-year well test retention period to either 1 or 2 years.

Response—For the most part, these recommendations were not adopted. The testing requirement in § 250.182(c) is for allocation purposes and, therefore, reflects the need to test more frequently to take into account the various changes in production rates that wells may experience specifically during the month for which allocations are made. Since most lessees test their wells more frequently than every 2 months, this should not impose any extra burden on lessees. The recommendations to shorten the time period for retaining test data was adopted and the final rule revised accordingly. Section 250.182(c) has also been changed in the final rule by the addition of a provision specifying that tests are to be conducted in accordance with procedures outlined in Subpart K, § 250.173, Well testing production, and can be used when submitting well tests as required in § 250.173.

Comment—One comment concerning § 250.183, Measurement of sulphur, was favorable.

Response—It has been decided to consolidate all rules concerning sulphur operations into a new Subpart P which is being developed and will be issued as a separate rulemaking. Therefore, the provisions for the measurement of sulphur have been deleted from Subpart L, and § 250.184 of the proposed rule has been redesignated in the final rule as § 250.183.

Comment—Five commenters submitted comments on proposed § 250.184 (now § 250.183) concerning site security. The comments were general in nature. Some commenters believe that site security regulations are not needed because operators will take the necessary steps to provide for site security or there is little possibility of theft of hydrocarbons. Several commenters also recommended that a specific security plan for each site not be required.

Response—The recommendation to not have site security regulations was not adopted. The recommendation to not require specific site security plans was adopted. Some regulatory provisions concerning site security are required to implement the recommendations of the Linowes Commission which reviewed allegations of theft of oil from Indian and Federal lands. The proposed requirements are intended to conform to the Commission's recommendations to (1) eliminate detailed requirements for site security and require instead that operators take the necessary steps to provide for site security and meet minimum standards and (2) require by regulation that all operators develop lease-site plans detailing how the operator would ensure security of the site. The plans would be required to be consistent with minimum Government standards and would be submitted to managers of the Federal royalty program. It appears that regulations are needed on site security, however, individual plans may not be needed for each site. The requirements in § 250.184 (now § 250.183) for protection of sales measurement devices and site security appear to provide sufficient protections. Accordingly, the second sentence in § 250.184 (now § 250.183) has been deleted.

Comment—There were five commenters on proposed § 250.184(a) (now § 250.183(a)) concerning site security provisions pertaining to the requirement for seals on sales measuring devices. Four commenters recommended that the seals not be numbered, therefore precluding a need to keep the records of numbered seal changes. A fifth commenter recommended that only seals that impact volumetric or quality measurements be required to be numbered and records kept. The commenters stated that there is little probability or possibility of hydrocarbon theft on an offshore location.

Response—These recommendations have not been adopted. If and when seals are used, they should be numbered and records of changes maintained as a precaution even though there have not been many known instances of theft of offshore oil. Situations have been observed where seals have been missing and the responsibility for this could not be determined. Some of the major pipeline companies have already initiated this requirement.

The proposed rule says that the list of seals should be maintained by the lessee at the lessee's field office nearest the OCS facility and be available for inspection by MMS respresentatives. The lessees seem to have a problem with this because it would require that they keep records which now are handled mostly by pipeline company personnel. In addition, this may be difficult at some locations which are unmanned and remotely located. Since the intent is for the list to be available when an MMS representative inspects the location, the final rule has been revised by replacing the phrase "by the lessee at the lessee's field office" with the phrase "at the field location."

Since the seals required by these regulations impact volumetric or quality measurement, they are all required to be numbered.

Comment—There were three commenters who submitted eight comments on § 250.184(a)(1) (now § 250.183(a)(1)) which contained a list of the metering unit components which must be sealed. Two commenters recommended adding the phrase "and sampling unit" to the first sentence of the subject paragraph. Three comments recommended revising § 250.184(a)(1)(ii) through (xii) with a more general description of the equipment because the proposed rule contained an unnecessary level of detail.

Response—These recommendations have been adopted. The equipment has been more broadly described, the number of items has been condensed, and the paragraph redesignated as § 250.183(a)(1)(i) through (iv).

Comment—There were three comments on § 250.184(a)(2) concerning the required sealing of lines on oil storage tanks. All three recommended

that this entire paragraph be deleted. They state that there is little benefit to be derived from sealing tank outlets for tanks on inaccessible OCS facilities.

Response—This recommendation was not adopted. The proposed requirement is consistent with another recommendation in the Linowes Commission Report which states that security plans should include a procedure for installing and monitoring locks and seals on access points. Section 250.184(a)(2) is issued as § 250.183(a)(2).

Comment—Four commenters submitted remarks on § 250.184(b) which is concerned with identification of storage tanks. Three of the comments state that this paragraph should be deleted because identification of structures, etc., is covered under other OCS regulations. A fourth comment recommends that small holding tanks and surge tanks be exempted from this requirement.

Response—The recommendation to delete this requirement was not adopted. Although identification of structures, platforms, etc., is covered in Subpart A, § 250.15, it does not cover tanks. Tank identification is needed to help identify tanks during sales verification and site security inspections, particularly at onshore custody transfer facilities. These regulations were only intended to govern tanks specifically used in royalty determination. Therefore, proposed § 250.184(b) (now designated § 250.183(b)) has been revised to specify that it includes only storage (sales or inventory) tanks used in the royalty determination process.

Comment—Four commenters submitted suggestions on § 250.184(c) concerning the recording of deliveries from meters and sales tanks.

Three of the commenters recommend retaining deliverability records for 1 year, and the fourth commenter recommends retaining these records for 2 years.

Response—Review of this provision resulted in a decision to delete it as redundant since run tickets are required under other regulations. Therefore, this provision is not contained in the final rule.

Comment—There were three comments recommending removal of liquid allocation meters from the provision in § 250.184(d) prohibiting a bypass around liquid allocation meters, royalty sales meters, and tanks. The reason for the suggestion was that most facilities have only one allocation meter in use and facilities must be shut in to repair the meter without the use of a bypass.

There was one other comment submitted concerning this paragraph. The comment recommended inserting the word "sales" before the word "tanks" in this paragraph.

Response—These recommendations were adopted.

Subpart M—Unitization

Subpart M consolidates provisions and requirements for the unitization of operations on OCS oil and gas leases previously located separately in OCS Order No. 11 and in regulations in Part 250. The final regulations in this subpart are being promulgated without major substantive changes from the proposed regulations. However, there were many revisions to clarify the wording and to improve the identification of the authorities, requirements, and procedures for various aspects of the unitization of operations. The most extensive change from current rules to the unitization rules proposed earlier and adopted herein is the incorporation of two MUA's into the regulations. One MUA is to serve as a pattern for the text of agreements executed by lessees for the unitization of OCS exploration, development, and production operations in all functions while the other is to serve as a model for unitization agreements for development and production operations within a single reservoir. These are based on the MUA which was published in the **Federal Register** on June 26, 1980 (45 FR 43256).

Comments and suggestions were received from 12 commenters regarding over 50 separate provisions of the subpart as proposed. Where the suggestions were determined to be improvements to the provisions of the proposed rules, appropriate modifications were made. However, none of the comments proposed major changes in the organization and structure of the subpart or the basic approach to the unitization of OCS oil and gas lease operations. The changes incorporated in the final rule, therefore, represent modifications of particular provisions for greater clarity or improvement in specific procedures or requirements. A discussion of specific individual comments follows.

Comment—One commenter suggested that the Regional Supervisor's authority to approve unitization be modified by adding the phrase "when the right of capture does not apply" in § 250.190(b).

Response—This suggestion was not adopted, and the phrase has not been added. The right of capture applies in any competitive situation. Inclusion of the language could prevent the Regional Supervisor from meeting his/her responsibility for the prevention of waste, protection of OCS natural resources, and protection of Federal royalty interests.

Comment—Deletion of the word "minimum" from the phrase "minimum number of leases" in § 250.190(c) was suggested by one commenter on the basis that it is restrictive of efforts to form large exploratory units.

Response—This suggestion has not been adopted because an exploratory unit is approved only if MMS determines that unitized operations promote exploration and development of a common geologic structure. The area to be covered by unitized operations should include only those leases needed to accomplish that objective, hence, use of the word "minimum." The language used is found in the present regulation.

Comment—Another commenter on the same point suggested that the subsection be revised to read "shall include, at a minimum, the number of leases" which would allow a greater than minimum number of leases to be included in a unit.

Response—This comment was not adopted. The proposed wording could prevent the unitization of operations where the proposed agreement included less than the entire geologic structure.

Comment—Four comments were received suggesting a revision of language in § 250.190(c) to allow portions of leases to be included in a unit. This change was recommended as necessary to allow the unitization of operations within a single reservoir that underlies parts of two or more leases.

Response—The suggested change has been adopted to make it clear that operations on less than an entire lease can be made subject to a unit agreement.

Comment—One commenter suggested that in § 250.190(d) the Regional Supervisor should not have to approve cost allocations between working-interest owners in a unit because each lease owner would have a similar goal of fair, equitable cost distribution.

Response—The commenter's views are correct when one considers agreements which relate to operations on OCS oil and gas leases which do not include net-profit-share (NPS) provisions. When an agreement covers operations on leases with NPS provisions, the Regional Supervisor must approve the provisions for the allocation of costs and credits in order to assure the protection of the Federal NPS. This is accomplished by the approval of the way in which the unit operating agreement would allocate costs and credits for capital recovery purposes relating to leases with NPS provisions.

This approval is particularly important when unit and nonunit wells are drilled and produced from a common facility using common production equipment.

To clarify this point, the last sentence in § 250.190(d) has been changed to read as follows:

> In units involving one or more net-profit-share leases, the unit operating agreement shall be approved by the Regional Supervisor as to the way that costs and credits are attributable to the net-profit-share leases.

Comment—One commenter expressed the view that some reasonable period of time must be allowed for engineering studies before the expiration of individual leases pursuant to § 250.190(e).

Response—The MMS does not share this view. When a lease is removed from a unit area by either the termination of the agreement or contractions of the area subject to the agreement, the lessee is not entitled to more time to conduct additional studies. At that point in time, the lessee would have had the life of the lease as extended by unitized operations to evaluate the lease's potential for production. The lessee would also have advance knowledge of the approaching contraction of the unit to permit it to commence drilling operations on the lease. In the absence of additional drilling operations, additional evaluation time would not be justified.

Comment—Three commenters suggested the inclusion of certain provisions from the current regulations concerning some essential attributes of and rights resulting from unitization. These provisions, which were incorporated in the MUA's but were not included elsewhere in the proposed regulations, deal with effective dates of initiations and terminations of unit agreements; the effect of these dates on individual lease terms; requirements concerning drilling, production and well-reworking operations performed in accordance with a unit agreement; and the effect of cessation of drilling operations on leases in a unit beyond their primary term. Commenters believe that these fundamental principles of unitization should be retained in the regulations so that they cannot be modified without a rulemaking process.

Response—The MMS has adopted these suggestions and added new paragraphs (f), (g), (h), and (i) to § 250.190 of the final rule to clearly state the impact of unitization in the regulations. The unit agreements to unitize operations in a particular area can depart from the text of the MUA when justified. These revisions to the regulations specifically address the impacts of unitization on OCS oil and gas leases.

Comment—Four commenters suggested deleting the definition of "competitive reservoir" in § 250.191(a) because that term is defined elsewhere in the regulations. Another commenter submitted a revised § 250.191(a) which has been rewritten for clarity.

Response—These suggestions were not adopted. However, the paragraph has been modified for clarity and by including the definitions of a "competitive reservoir" and a "producible well completion" as found in OCS Order No. 11. The MMS believes both definitions should be included in § 250.191(a) to eliminate any possible confusion as to the application of the paragraph.

Comment—Four commenters suggested the addition of language in § 250.191(c) concerning unitization of a competitive reservoir to provide discretion for a Regional Supervisor to determine whether or not a joint plan for drilling and production should be submitted and to direct lessees to submit such a plan if an agreement cannot be reached.

Response—This suggestion has merit and is needed for instances when lessees do not agree on a plan. The proposed paragraph has been modified to include provisions for the Regional Supervisor to direct the submission of a joint plan.

Comment—Also in § 250.191(c), referring to submission of a joint plan, the same commenters suggested replacing the word "drilling" in the first sentence with the word "development."

Response—This change was not adopted because a joint plan should be specific as to the type of development activity described in the plan. Both drilling and production are types of development activity.

Comment—Four commenters suggested the addition of language to allow for the extension of time for the submission of a joint plan for drilling and production operations.

Response—The MMS did not incorporate this suggestion into the rule. Lessees will have ample foreknowledge of the need for the development of a plan for drilling and development operations.

Comment—Four commenters suggested revising § 250.191(c) concerning unitization of a competitive reservoir when lessees cannot agree on a joint DPP. The revision proposed that in this situation each lessee shall submit a separate plan and, if the differences in the separate plans are not resolved at a subsequent hearing and the Regional Supervisor determines that conservation will be best served by unitization of operations, unitization will be required.

The commenters supported this procedure because it allows for a hearing to discuss the reasons for differences and permits the issues to be presented. Adjudication by the Regional Supervisor furnishes an alternative to unitization if no conservation matters are at stake.

In the same paragraph, one commenter suggests that the phrase "unitization may be required" in the last sentence be revised to read "unitization *will* be required." The commenter believes that if lessees/operators of a competitive reservoir cannot agree on a joint plan of operations and MMS has determined "conservation will be served by unitization," MMS should require unitization.

Response—The MMS believes that both suggestions have merit and has modified the language in § 251.191(c) accordingly. A hearing will provide opportunity for discussion and possible resolution of differences and for adjudication by the Regional Supervisor. The initiation of steps to require compulsory unitization of operations is appropriate when the determination has been made identifying the conservation purpose to be served.

Comment—One commenter recommended that § 250.192(a) be revised to provide that a proposed initial plan of operations be included in the information to be filed with a request for approval of unitization. This would be consistent with the requirements in section 9.3 of the MUA.

Response—This recommendation was adopted.

Comment—Four commenters suggested that in § 250.192(b) the discretion of a Regional Supervisor to approve variations from the MUA be conditioned by adding the requirement that such variations be "for good cause."

Response—This recommendation was adopted. The addition of this phrase requires that variations from the MUA be justified by good and logical reasons. Examples of instances where there may be significant departures from the texts of the MUA in § 250.194 include unit agreements which include both State and Federal submerged lands

Comment—There was a recommendation by one commenter that language revisions be made to § 250.192(c) to clarify that a Regional Supervisor will not approve a unit agreement until it is first executed by the lessees.

Response—This suggestion was adopted and the appropriate changes made.

Comment—Several commenters suggested revisions to § 250.193(a) which provides for compulsory unitization if the Regional Supervisor determines that unitization is necessary to achieve the three criteria specified in the Act or if it is proposed by fewer than all the lessees of a proposed unit area.

The commenters believed that § 250.193(a) should provide for compulsory unitization when only one of the three listed criteria is satisfied, rather than requiring all three. It was suggested, therefore, that the word "or" replace the word "and" in the listing of the criteria.

Response—This suggestion has been adopted. The unitization of operations may be required to prevent waste, conserve natural resources of the OCS, or protect correlative rights.

Comment—Four commenters suggested that § 250.193(a) be revised to clarify that compulsory unitization be evaluated by the same criteria whether initiated by a request of fewer than all lessees or by the Regional Supervisor. To accomplish this, the phrase "is necessary for the reasons stated above" should be inserted in § 250.193(a) to refer to the application of the same criteria for units proposed by fewer than all lessees as are applied when a Regional Supervisor acts independently to impose compulsory unitization.

Response—This suggestion was not adopted, but the paragraph has been revised to make this a clear requirement.

Comment—Four commenters suggested that proposed § 250.193(a)(2) be deleted because a "previously approved unit agreement executed by less than all lessees" could include an agreement approved 20 or more years ago in a field that may have no relationship to the unit now being proposed, said agreement having been executed by one of the lessees.

Response—The MMS has reviewed the provisions of § 250.193(a) and decided to delete § 250.193(a)(2) and restructure the paragraph by merging proposed paragraph (a)(1) into paragraph (a).

Comment—Four commenters suggested that § 250.193(b)(1) concerning the proposed unit agreement required to be filed by lessees seeking compulsory unitization be modified to allow the same flexibility for variations from the MUA as are provided for in § 250.193(a). These commenters also suggested the addition of language requiring that lessees seeking compulsory unitization provide nonconsenting lessees with the same information at the same time as it is filed with the Regional Supervisor.

Response—These suggestions were adopted to recognize the provision for proposed unit agreements for compulsory unitization under § 250.193(a). Appropriate language changes have been made in § 250.193(b)(1). The suggestion for requiring timely notification of nonconsenting lessees also has been incorporated into the final rule by adding the word "simultaneously" so that the phrase "shall simultaneously serve copies" appears in the last sentence of § 250.193(b)(1).

Comment—One commenter proposed revisions to § 250.193(b)(1) which would require that notice be served to nonconsenting lessees within 24 hours of filing with MMS and would require proof of the date of filing and date of notice to nonconsenting lessees.

Response—These suggestions were not adopted. The objective of the first suggestion is accomplished by adoption of the suggestion in the previous comment to require that notice to nonconsenting lessees be given simultaneously with filing a request with the Regional Supervisor.

Comment—Four commenters proposed a revision to § 250.193(c)(2) to require that a transcript be made by a court reporter. The reason given for this suggestion was for the protection and satisfaction of all concerned parties.

Response—This suggestion was adopted. The rule has been revised to require the Regional Supervisor to cause a verbatim transcript be prepared by a court reporter. The cost of the transcript is to be borne by the party seeking compulsory unitization.

Comment—Two commenters objected to the variations in the combinations in which the terms "oil," "gas," and "hydrocarbons" are used throughout § 250.194. For example, "oil or gas, or both," "oil and/or gas," "oil and gas," "gas or oil and/or condensate" are described as being used in a seemingly interchangeable and random manner. Both commenters recommended replacing such terms with the term "unitized substances" throughout the MUA's.

Response—The suggestion has not been adopted. The term "unitized substances" is not specific enough for all applications in the agreements. A closer reading of the model agreements should show that there are reasons for the variation, i.e., they are not randomly interchangeable.

Comment—In § 250.194, Model unit agreements, four commenters suggest the word "unit" be inserted between the words "conduct" and "operations" in the definition for unit operator. They state there are instances where individual tract owners reserve the right to conduct nonconsent and/or tract operations to explore for or delineate new reservoirs or extensions of old reservoirs.

Response—The suggested revision has been adopted for both § 250.194(a), Model unit agreement for exploration, development, and production units (MUA–E), and § 250.194(b), MUA for development and Production (MUA–D/P) for consistency. The commenters' reasons for the revision are more applicable to § 250.194(b) MUA–D/P. Section 250.194(a), MUA–E, requires that all strata bearing hydrocarbons in paying quantities be unitized. All unit operations and those conducting them require the approval of the Regional Supervisor.

Comment—One commenter suggests the definition for the term "participating area" be revised to clarify that the participating area is the part of a reservoir in the unit area that is reasonably proven (to be capable of producing hydrocarbons in paying quantities).

Response—This recommendation has not been adopted. An exploration/development unit may contain more than one reservoir within the unit area. Producible wells, geologic information, and engineering data determine the extent of the reservoir covered by a participating area and the nonproductive portions of the formation involved.

Comment—Several commenters suggest inserting the term "and the unit operating agreement" after the word "agreement" in the first sentence of section 4.2 in both MUA's. This would expand on the relationship between the working interest owners and the unit operator.

Response—This suggestion was not adopted. The unit agreement recognizes the existence of the unit operating agreement, and these should be two separate, distinct documents with the unit agreement taking precedence when a conflict occurs.

Comment—One commenter recommends revising section 5.1 in both MUA's by making the resignation of the unit operator subject to the unit operating agreement.

Response—The recommended revision has not been adopted. When there is a conflict, the unit agreement prevails over the unit operating agreement. If the working-interest owners of a unit desire to place restriction on the resignation of a unit operator in the unit operating agreement, such restrictions should be enforced by that instrument. The terms of unit operating agreements vary from agreement to agreement, depending on

the negotiations of the parties. The terms of the unit agreement should not be limited by variations in unit operating agreements.

Comment—Several commenters suggested adding language to section 5.1 in both MUA's to provide for transfer of operations when a unit operator resigns. The proposed rule provided for only suspension or abandonment of operations.

Response—The proposed revision has been adopted. This revision makes section 5.1 more consistent with section 6.2.

Comment—One commenter recommends that section 5.2 in § 250.194(a), MUA–E, and § 250.194(b), MUA–D/P, be changed by revising the first sentence to read as follows "The unit operator may be subject to removal pursuant to the provisions of the unit operating agreement."

Response—This revision has not been adopted because it conflicts with the requirements of Article VI which allows options for the removal of the unit operator to the working-interest owners including the provisions of the unit operating agreement.

Comment—Four commenters suggested revisions to section 5.3 of both MUA's concerning the obligations of unit operators who resign or are removed. Language was suggested to modify the proposed regulation which applied to "any obligation." The commenters said that this application is so broad it could result in unjustly imposing working-interest obligations on the unit operator.

Response—The suggested change has not been adopted. The unit operator is delegated and charged with the authority and responsibility to perform on behalf of all working-interest owners. Therefore, the unit operator is responsible to carry out any and all obligations under the unit.

Comment—Three commenters suggested revising the last sentence in section 5.4 in both MUA's by replacing the phrase "other assets used for conducting operations for the unit area" with "other assets all owned solely by the unit joint account."

The reasons given for this suggestion were that "several events could occur all of which would be detrimental to the safe and orderly conduct of operations." One situation described by the commenters was the instance where wells which may be subject to one or more unit agreements are drilled from a platform which contains lease wells owned and operated by the lessee who is also the Unit Operator under the unit agreement (JJ). Under the provisions of the proposed MUA, the former unit operator would be required to relinquish all assets used for conducting operations for the unit area. The commenters suggest that this would mean that the successor unit operator would be required to assume the operation of the lease wells and unit wells "with no contractual relationship in existence and no vested interest in much of the production, wells, and facilities that it would suddenly be required to operate. The commenters see in these potential problems a set of circumstances which might significantly delay or prevent the formation of voluntary unit agreements for the prevention of waste of natural resources.

Response—This recommendation has been adopted in order to facilitate the formation of voluntary unit agreements.

Comment—One commenter suggested revising section 6.1 in both MUA's to replace the requirement for the designation of successor unit operators by vote of the owners of a majority of the working interests with the requirement that the "operator shall be designated * * * pursuant to the provisions of the unit operating agreements."

Response—This suggestion has not been adopted. Section 6.1 provides options and flexibility for designations (and removal) of successor unit operators. The commenter's suggested revision is one of the options provided for by proposed section 6.1.

Comment—Four commenters suggested revising both MUA's in section 6.2 by replacing the word "resignation" with the phrase "unit operator's intent to resign" in order to parallel more closely the language in section 5.1.

Response—This change has been adopted.

Comment—Four commenters suggested changing section 6.2 in both MUA's by deleting the phrase "or may declare this unit terminated" and replacing it with "and if such successor unit operator is unwilling or unable to serve, then the Regional Supervisor may terminate this agreement," because MMS should only terminate as a last resort.

Response—This proposal was not adopted. First, the proposal would dilute the agreement and the Regional Supervisor's authority. Second, MMS does not automatically terminate a unit if its purpose has not been accomplished without considerable effort to maintain that unit in an active status.

Comment—Four commenters stated that section 7.3 in both MUA's should be made compatible with the provisions in § 250.192(c).

Response—This suggestion has not been adopted. Section 7.3 refers to previously executed unit operating agreements which are required to be filed with the unit agreement. The provisions of § 250.192(c) address unit agreements prior to approval.

Comment—Four commenters suggested correcting section 8.1 of both MUA's to change the word "appeal" to "appear" in the first sentence which concerns the right of a unit operator to appeal before DOI or any other legally empowered body on behalf of the working interest owners.

Response—The correct word is "appear" and the correction has been noted.

Comment—Four commenters suggested revising section 8.1 of both MUA's to give nonoperators the right to appear by replacing the third sentence with a new one to read as follows: "However, the unit operator's right to appear shall be without prejudice to the right of any affected working-interest owner who shall have the right, at his own expense, to be heard in any proceeding on their own behalf."

Response—This change was not adopted because it is unnecessary. Under the existing language, all working-interest owners already have the right to appear and to be heard in any proceeding at their own expense.

Comment—Four commenters proposed a revision of both MUA's in section 9.2 by adding at the end of the first sentence, the phrase "or unless extended by the Director pursuant to 30 CFR 250.13(b)." This revision would bring the model agreement into conformance with the revised regulations at § 250.13(b) under which the Director may approve up to a 180-day period between operations.

Response—The proposed language has been added to conform with the provision of § 250.13(b).

Comment—There were four comments that the first sentence of section 9.3 in Article IX of both MUA's conflicts with § 250.192(c) and, therefore, should be modified.

Response—No change has been made to section 9.3. The unit operator must submit an initial plan of operation at the time the unit agreement is submitted for approval. The Regional Supervisor may approve the unit agreement and require modification of the proposed plan of operation when deemed appropriate pursuant to § 250.192(c).

Comment—One commenter recommends that the first sentence of section 11.1 of the MUA–E concerning the identification of lands to constitute a participating area be revised. It was

suggested that the word "sustained" be added before the word "production" in the phrase "Prior to commencement of sustained production of unitized substances." This refers to the timing of the unit operator's submission of information required to constitute the initial participating area. The reason for the suggestion was that in order to protect the interest of all parties, a participating area should be established prior to commencement of production. Additionally, it should be clarified that "production" does not mean production testing.

Response—This recommendation has not been adopted. Section 11.1 allows flexibility in the submission of the participating area subject to the Regional Supervisor's approval. All parties are protected as section 11.1 requires the participating area to be approved by the Regional Supervisor effective the date production commences.

Comment—Two commenters suggested revising the second sentence in section 11.2 of § 250.194(a), MUA–E, by replacing the phrase, "in which the information is obtained which provides the basis for the" with the phrase "following the date of." The date of acquiring knowledge or information is subjective and can be argued whereas the date of approval is not.

Response—This recommendation has not been adopted. This section provides the Regional Supervisor the flexibility to establish an alternative effective date for a revision of a participating area when that action is justified.

Comment—One commenter recommended replacing the phrases "accumulation of unitized substances" and "pool or zone" with the term "reservoir" in section 11.3 of § 250.194(a), MUA–E.

Response—This recommendation has not been adopted. This type of unit may (and usually does) include more than one reservoir or zone within a participating area. The language proposed and adopted in the final rule is flexible enough to meet the requirements of the majority of circumstances that arise. The commenter's proposed revision was determined to be too restrictive.

Comment—Two parties commented on the royalty payment provisions in § 250.194(a), MUA–E, section 12.1, and § 250.194(b), MUA–D/P, section 10.4. Both commenters feel that the payment of royalty by the unit operator should be at the discretion of the unit operator and the various nonoperators and that it must be the subject of an agreement between unit operator and the respective individual unit's working-interest owners. One commenter recommended deletion of the requirement that the unit operator make all royalty payments for reasons stated.

Response—These recommendations have not been adopted. The payment of royalty provision is flexible, and language suggested by the commenters may be approved for a specific unit agreement when justified. Therefore, the "Model Agreement" remains unchanged.

Comment—Several parties commented on the basis for allocation of unitized substances in § 250.194(a), MUA–E, section 12.1 (section 10.1 of § 250.194(b), MUA–D/P). The comments suggested that allocations be based on equivalent net-acre feet of oil and gas in place. The allocation would be based on the volumes of oil or gas in place as of the effective date of the unit. The reason given for the suggestion is that an acre foot of oil and an acre foot of gas do not have the same value, and therefore, allocations should be based on current reservoir conditions.

Response—This suggestion was not adopted. The MUA is sufficiently flexible that the Regional Supervisor may approve the suggested method of allocation or other variations from the model agreement when the alternate formula is justified as better representing equities.

Comment—One commenter recommended that it should be made clear in the second sentence of section 12.1 of § 250.194(a), MUA–E, who makes the decision to allocate production on a volumetric basis or a surface-area basis.

Response—This recommended change has not be adopted. All of the exploration/development units have been voluntary, and the unitization agreements have defined the basis for the allocation of unit production.

Comment—Several parties commenting on § 250.194(a), MUA–E, section 12.1, suggested adding the following:

> However, unless the parties agree specifically to the contrary, committing leases hereto shall not be regarded as pooling royalty obligations under the committed leases nor as treating such royalty obligations as a unit expense.

The suggestion was based on a perceived need for clarification to resolve a difference in interpretation that has arisen recently.

Response—This suggestion was not adopted. The MMS believes the calculation of royalty for each lease, as stated in the model agreement, does not require further elaboration.

Comment—Four commenters proposed the addition of the phrase "either currently or previously" to the first sentence of section 13.1 of the MUA–E referring to the time when a lease is not entitled to receive an allocation of unit production. The reason given for the suggestion was to make section 13.1, which provides for the adjustment of a unit area by the automatic elimination of any lease that has not been entitled to receive an allocation, consistent with section 10.2 which states that unit areas shall not be reduced on account of the depletion of unitized substances.

Response—The proposed change has not been adopted because it is not necessary. As provided in section 10.2, once a lease is recognized as being in a participating area and is allocated production, that allocation cannot be reduced because of depletion of the unitized substances for which it was established. Under section 13.1, only those leases which never had an allocation or which received an allocation but was subsequently determined not to be entitled to an allocation would be eliminated from a unit. The two provisions are not inconsistent with each other.

Article XIV of the MUA–E addresses relinquishment of leases. This provision has generally appeared in past MUA's. For consistency, a similar provision has been added as Article XI of the MUA–D/P in the final rule. As a result, all Articles after X in the MUA–D/P have been renumbered accordingly.

Comment—One commenter recommended that section 16.2 of the MUA–E concerning requirements for termination of agreements be revised to substitute language which would provide for termination "at any time by the working interest owners as provided in the unit operating agreement." The same suggestion was made for section 12.2 (now 13.2) of the MUA–D/P.

Response—This recommendation has not been adopted. The proposed language is flexible and provides the working-interest owners two options in terminating the unit. Termination of the unit agreement should be in accordance with the terms of the unit agreement and not the unit operating agreement.

Comment—One commenter recommended modifying the last sentences of section 17.2(c) of the MUA–E and section 13.2(c) (now 14.2(c)) of the MUA–D/P to read as follows: This subsection shall not operate to continue any lease wholly excluded from the unit area by adjustment pursuant to Articles X or XIII.

Response—For clarity, the phrase "pursuant to Articles X or XIII" has been added to the end of the last sentence of section 17.2(c) of the MUA–

E and "pursuant to Article X" has been added to the end of the last sentence of section 13.2(c) (now 14.2(c)) of the MUA–D/P.

Comment—One commenter recommended modifying section 20.1 of the MUA–E and section 16.1 (now 17.1) of the MUA–D/P concerning the effective date of automatic termination for failure to remedy default. The recommendation was to make the termination effective as of the day the notice of default is received by the unit operator.

Response—This recommendation has not been adopted. The proposed language to effect termination as of the first day of the default makes termination effective only after the failure of the unit operator to remedy a default within a reasonable time following notice of the default.

Comment—Several commenters recommended the deletion of § 250.194(a) MUA–E, section 22.2, and 194(b) MUA–D/P, section 18.2 (now 19.2) because they deal exclusively with the relationship between a unit operator and working-interest owners. Therefore, these requirements properly belong in a unit operating agreement.

Response—These recommendations have not been adopted. The MMS believes that the provision of this article is necessary because it tells how covenants are to be interpreted under the unit agreement.

Comment—One commenter recommended that § 250.194(b), MUA–D/P, Article II be retitled as "Incorporation and application" and a new section 2.2 be added to state that the unit agreement shall not apply to any operations conducted on leases within the unit area and conducted solely for the purpose of exploring for, developing, or producing oil or gas on any portion of such leases other than the unitized reservoir.

The commenter also recommends the last two lines of § 250.194(b) MUA–D/P, section 3.1, which describes the area of the unitized reservoir for a specific unit agreement be revised to add the phrase "insofar as it underlies the unit areas" to further define the unitized reservoir. No reason was given for either suggestion.

Response—The proposed revisions have not been adopted because they are unnecessary. The "area" covered by an agreement to unitize operations in a single reservoir includes only those portions of leases that envelope the productive or hydrocarbon-bearing portions of the unitized formation in accordance with the provision of § 250.190(c). This MUA is designed to govern only operations pertaining to the development and production of oil and gas from the unitized formation(s).

Comment—Several commenters suggested the addition of the term "OCS___" after the words "Well No." in § 250.194(b), MUA-D/P, section 3.1. This would identify the lease on which the referenced well is located.

Response—This suggestion has been adopted and the changes made.

Comment—Several commenters suggested revisions to § 250.194(b), MUA–D/P, section 3.4. In the third sentence referring to Exhibit C, they proposed adding the word "equivalent" before the word "productive" in the phrase "number of productive net acre-feet." It was also suggested that the word "equivalent" be added to the fourth sentence in this same paragraph before the word "net" in the phrase "number of net ___ acre feet." The reason given for this suggestion was that, in instances of unitization of an oil reservoir containing associated gas and of multiple reservoirs containing oil or gas, acre-feet of different hydrocarbons do not have the same value. In order to avoid unfair and unjust treatment of both the royalty owner (in the case of different royalty rates and net profit leases) and the lessees, an equivalent acre-foot value for each type of hydrocarbon must be determined. The equivalence ratios must recognize that recovery factors vary as a function of the type of hydrocarbon and of the reservoir-drive mechanism.

Response—The suggested revision has not been adopted. Although it is true that the same volumes of different hydrocarbons do not have the same value, MMS believes that section 3.4 should reflect the general wording as proposed in the model form. It is also recognized that the actual method of allocation proposed may vary, and changes in the specific wording must be approved by the Regional Supervisor as appropriate and justified.

Comment—One commenter recommended that in the second sentence of section 9.2, in § 250.194(b), MUA–D/P, the words "a reservoir" be changed to "this unitized reservoir."

Response—This revision has been adopted for clarity and specificity.

Comment—Several commenters believe that § 250.194(b), MUA–D/P, section 10.1, should be revised to provide for allocations to be based on equivalent net-acre feet of oil and gas in place rather than a volumetric basis. Also, the allocations should be based on the then-current oil or gas in place as of the effective date of the unit. The reason is that an acre-foot of oil, as compared to gas, does not have the same value, and further, value should be based on current reservoir conditions.

Response—This suggestion has not been adopted. The supervisor may approve or require use of the method of allocation proposed by these commenters or other variations from the model agreement when it is warranted and justified.

Comment—Commenters also propose to insert the following at the end of section 10.1:

> However, unless the parties agree specifically to the contrary, committing leases hereto shall not be regarded as pooling royalty obligations under the committed leases not as treating such royalty obligations as a unit expense.

Rationale is clarification to resolve a difference in interpretation that has arisen recently.

Response—This proposal has not been adopted. The change is not necessary because the agreement covers operations only. It does not result in any changes in the ownership of interests and the assignments of obligations under individual leases. The royalty and NPS due under each lease are to be calculated and paid on the basis of the oil and gas production allocated to that lease.

Comment—In § 250.194(b), MUA–D/P, section 10.2, several commenters suggested changing the effective date for revision of a unit area from the first day of the month in which is obtained the knowledge or information on which such a revision is predicated to the first day of the month following the date of approval of the revision by the Regional Supervisor. The reason for the suggestion was that the date of acquiring knowledge or information is subjective and open to dispute whereas the date of approval is not.

Response—This proposal has not been adopted. Because it is not necessary to change the provision in order to use the effective date for revisions suggested by the comment. Section 10.2 provides for flexibility in identifying an effective date for changes in the allocation of production when that effective date is justified and is approved by the Regional Supervisor.

Comment—Four commenters proposed that § 250.194(b), section 10.3, concerning revision of a unit area and allocation of production, be revised to add the word "equivalent" before the words "net-acre feet" in each instance where that phrase appears in this article.

Response—This suggestion has not been adopted. Any parameter used in section 10.3 will have to be compatible with the method approved to establish

the original allocation. Therefore, the word "equivalent" has not been inserted in the model form.

Comment—Three commenters suggested the deletion of the last two sentences of § 250.194(b), MUA–D/P, section 10.3. These sentences provide that the net acre-feet credited to land originally in a revised unit area will not be subject to change, that increasing the total number of net acre-feet of the new lands will be the only change, and that there shall never be any retroactive allocation of interest in the unitized substances produced because of a revision of the unit area.

These commenters proposed replacing these sentences with provisions calling for a determination of the total number of equivalent net acre-feet in the expanded unitized reservoir, a redetermination of the total number of equivalent net-acre feet in the reservoir(s) underlying the original unit area as of the date of expansion, and a determination of the equivalent net-acre feet in the portion of the reservoir underlying the area being added to the unit. It was further suggested that the resulting numerical values be used as factors in equations or ratios which were proposed for use in two separate calculations for allocations of produced substances—one for allocations to tracts in the original unit area and the other for tracts added to the unit area.

The reason given for this suggestion was that the method in the proposed regulations for determining tract percentages of participation would result in gross inequities to working-interest owners and royalty owners if leases having different royalty rates or net-profit shares are brought into the unit as a result of expansion. Also, there would be at least two different values of acre-feet in the official fields—one value for unit participation allocation and another value for MER purposes. Lessees should not be required to place in official records data which they believe to be technically incorrect. The commenters stated that proposed replacement for a portion of section 10.3 allows the best technical interpretation to be utilized for both purposes and maintains the established equity relationship between participants in the original unit area and the area added to the unit.

Response—This suggestion has not been adopted. The method proposed by MMS has been used in many existing approved unit agreements, and no inequity to working-interest owners has been demonstrated, whereas the method proposed by the commenters has not been shown to be a superior method. The provisions of proposed section 10.3 assure equitable allocation of production to each lease affected within the unit area upon expansion of the participating area.

Also, the unit operator is responsible for submitting an MER for the unitized reservoir(s). When a reservoir expansion is affected, the MER should be revised to reflect the same value of acre-feet for unit participation and for MER purposes. Therefore, no change is necessary for this reason.

Comment—One commenter recommends adding the phrase "in the unitized reservoir" between the word "hereto" and the word "and" in the first sentence of section 18.1 (now 19.1) of § 250.194(b).

Response—This addition has been adopted.

Subpart N—Remedies and Penalties

Subpart N combines the provisions in current §§ 250.80–1, Remedies, and 250.80–2, Penalties.

There were eight comments received, six from the oil and gas industry, one from a State agency, and one from an environmental group. The final rule is essentially the same as the proposed rule with minor changes based primarily on the comments. The specific comments are addressed below. The final rule has eliminated unnecessary and redundant provisions, especially those which contained MMS internal procedures and provisions that merely repeated provisions in the Act.

Comment—Several commenters objected to various aspects of the rule concerning Reviewing Officers, including the choice of person and authority of the Reviewing Officer to investigate a potential violation. Some commenters objected to the appointment of an MMS employee as a Reviewing Officer and suggested appointment of an administrative law judge to handle civil-penalty matters. They expressed concern with possible bias, the placing of unreasonable burdens on MMS employees, and a lack of education and training to handle judicial matters.

Response—The suggestion was not adopted. Reviewing Officers will continue to be selected from experienced, senior MMS employees with a background in regulatory and operational activities. Experience has shown that such personnel are able to properly conduct the review and analysis of information in the case file, conduct a fair hearing, and arrive at an impartial decision based upon the evidence in the record. Provision is made in § 250.201(e) for a party to request transfer of the case to another Reviewing Officer if there is any question of bias or partiality. Additionally, § 250.200(a)(3) assures that the Reviewing Officer will have no other involvement for the investigation or prosecution of the alleged violation. Therefore, MMS believes that ample safeguards are provided to assure the selection of a qualified, impartial Reviewing Officer. These cases are quasi-judicial proceedings within the context of administrative law. If a hearing is requested, it is an informal meeting to receive evidence from the party accused of the alleged violation. The MMS employees that will serve as Reviewing Officers have had experience with similar hearings concerning a variety of regulatory matters and, therefore, assignment of an administrative law judge is not necessary.

Comment—Several commenters objected that the authority provided to the Regional Director and chairmen of investigative panels is too broad. They contend that it went beyond that which is granted in the Act, it will lengthen and complicate the proceedings, and it will allow the Regional Director to conduct a trial and violate due process.

Response—The authority provided to the Regional Director and others is in keeping with the responsibilities of those officials and is provided in section 22 of the Act. This authority is to conduct investigations of alleged violations and accidents in the enforcement of regulatory activities. The Regional Director must see that an alleged violation is thoroughly investigated prior to the preparation of a civil-penalty case file and appointment of a Reviewing Officer. The exercise of this authority need not result in formal judicial proceedings resembling a trial.

Comment—Numerous commenters requested deletion of § 250.200(a)(2) concerning possible violations for which the granting of any time for correction would be unreasonable. They felt the authority is contrary to the Act and specifically the judicial interpretation of section 24(b). Another commenter suggested that there should be a positive showing that a reasonable time for corrective action is not in order.

Response—The recommendation was adopted in light of *Chevron, Inc.* v. *Watt*, 564 F. Supp. 1256 (E.D. La. 1983).

Comment—One commenter supported the provision in § 250.200(a)(2) and further suggested that all violations which result in increased risk to human safety and the environment result in the preparation of a civil-penalty case. To ensure environmental protection, penalties must be pursued even though reasonable corrective action has been taken. It was also requested that

affected States be given notice of violations.

Response—It is believed that § 250.200 provides appropriate coverage for the variety of situations that have and may occur. The law and interpretive court decisions require notification of a violation and the expiration of a reasonable period allowed for corrective action before liability for of a civil-penalty. The vast majority of violations detected by MMS officials are corrected within 7 days of detection, and a large number are corrected immediately (i.e., before the MMS official leaves the facility) or within a few hours. The civil-penalty provisions are intended for those situations where, after notice of a violation, there is undue delay in taking corrective action or where corrective action is not useful or possible. A periodic report of civil-penalty activities will be made available to the public. A special additional notification to affected States of individual violations is unnecessary. All violations are not threatening to human safety or the environment. Historically, most violations are minor and have not warranted the initiation of civil-penalty proceedings.

Comment—A commenter objected to the third example cited in the preamble to the proposed rule of a violation where corrective action cannot be accomplished in a reasonable period of time. The cited example concerns excessive rig movement or anchor-line tension prior to disconnect during floating drilling operations. They felt a civil-penalty was not warranted when the cause was a "freak environmental event."

Response—The MMS continues to consider the example to be a valid one. All contributing factors including cause must be taken into account in the determination of whether to assess a civil penalty. In the circumstance cited by the commenter, a civil penalty would not be forthcoming. The examples were intended to demonstrate where action should be taken for violations over which the lessee had control and failed to act; i.e., when the operator's failure to take corrective action could be expected to result in an accident, or otherwise create undue risk to the safety of rig personnel or the environment.

Comment—Several commenters suggested deleting § 250.200(a)(5) because section 24 of the Act does not provide for subpoena authority.

Response—The suggestion was not adopted. Section 22(f) grants the authority to summon witnesses and produce evidence for an investigation. Such authority may be needed to fairly and impartially determine whether a civil-penalty should or should not be assessed based upon the evidence in the case file. The initial evidence prepared by MMS or submitted by a party in writing or at a hearing may be contradictory or incomplete; and therefore, the Reviewing Officer may determine that additional evidence is necessary. This authority is also implied in the provision of section 24 that a party charged with a violation be given an opportunity for a hearing.

Comment—Several commenters made suggestions for word changes, namely the substitution of "significant" for "sufficient" in § 250.200(a)(1) and deletion of "probably" in § 250.200(a)(1) and (b).

Response—The suggested changes in language were not adopted. Past experience has shown that the initiation of civil-penalty cases is not undertaken frivolously. Civil-penalty proceedings have been initiated only when the level of evidence is adequate to support such action.

Comment—It was suggested to add language in § 250.201(f) to provide for cross-examination of witnesses by any party to a civil-penalty case to assure due process and full and true disclosure of the facts.

Response—The suggestion to allow cross-examination of witnesses was not adopted. These hearings are administrative and informal and are intended to provide opportunity for the party(s) to offer any facts, statements, explanations, or other materials which bear on the issues or which may be relevant to the amount of the penalty which might be assessed. They are not formal proceedings on the record, and rules of evidence need not apply. Cross-examination would introduce procedural and evidentiary requirements beyond the scope and capacity of these hearings and would elevate the proceedings to an unnecessarily high level of formality.

Comment—Commenters suggested that the regulations in § 250.202 concerning hearing procedures stipulate that the Government's case be complete at the time of a hearing and that the alleged violator be consulted in regard to "notice" of matters not presented at the hearing.

Response—The suggestions were not adopted. The case against the alleged violator will basically be complete at the time the opportunity for a hearing is offered. However, the party accused of the violation may present evidence at a hearing that could alter the perception of the case. New evidence may present the need for additional information to resolve conflicts, and the alleged violator must be provided an opportunity to comment. To not allow new evidence would be detrimental to all parties. Section 250.202 already provides for consultation on all matters presented to the Reviewing Officer, either at a hearing or subsequently submitted in the case file.

Comment—Several commenters requested deletion of the reference in § 250.203, Reviewing Officer's decision, to § 250.200(a)(2) concerning situations when no time for corrective action is reasonable.

Response—The reference has been deleted for the same reasons that the provision (§ 250.200(a)(2)) was deleted, with the understanding that in some circumstances it may be unreasonable to allow any time for corrective action after notice has been given.

Comment—Some commenters objected to the provision in § 250.204 that payment of a civil-penalty is not due until 30 working days after receipt of the Director's decision. It was also suggested that the alternative of posting of a bond in lieu of payment be provided for and that payment not be due until the appellant has fully exhausted all administrative relief and/or any related litigation has been finalized. Similar comments were received concerning payments of civil-penalties in § 250.206.

Response—The suggestions have been adopted in part. In order to conform to the hearings and appeals procedures in 30 CFR 290.3 and 290.5, the filing of an appeal with the Director must be done within 30 calendar days after receipt of a decision by the Reviewing Officer. Therefore, the word "working" has been deleted from the first sentences in §§ 250.201(a), 250.204(a)(1), and 250.206(b). Similarly, paragraph (2) and the parenthetical reference in the proposed paragraph (3) in § 250.204(a) have been deleted. After the receipt of the Director's decision in response to an appeal of a Reviewing Officer's decision, the appellant may take an appeal to the DOI Board of Land Appeals within 30 days (thus, the 30-day payment requirement). Provision has been made in § 250.206 for the posting of a bond in lieu of payment of a civil-penalty when the Director's decision is appealed under 30 CFR Part 290. Once administrative relief is exhausted through the appeals process, payment of the civil-penalty becomes due and should be made and not postponed pending appellant's initiation of litigation. Section 250.204(e) has been revised to avoid repetition of the provisions in § 250.23 and to include a previously omitted provision.

Comment—A number of commenters disagreed with the provision to allow

the Regional Director to reopen a case based on newly found evidence. They felt that only the non-Government party should be able to reopen a case because of the constitutional protection against double jeopardy.

Response—The MMS does not share this view. Either party in a civil-penalty case should be allowed to reopen the case based upon newly found evidence that was not available at the time of any previous proceedings. It is fair and equitable to provide for reopening the record for reconsideration of previous action when the initial action was based on inaccurate or incomplete evidence. Section 250.205(c) has been revised by substituting the phrase "pursuant in § 250.203(a)" for the phrase "at anytime." A civil penalty is a sanction that is applied when justified by a failure to comply with requirements and is based upon evidence gathered by MMS or submitted for the record by the alleged violator. The concern over double jeopardy is misplaced as these are civil not criminal proceedings.

Comment—Commenters objected to the deletion of the content of the preexisting regulations covering penalties and recommended that the specific monetary penalties be retained in the rules to emphasize the serious nature of such violations.

Response—While MMS agrees with the need to emphasize the serious nature of violations, it is not felt that specific monetary penalties need to be iterated in the regulations. Reference has been added to the applicable penalty provisions in section 24 of the Act.

Comment—It was requested that public notice be provided of any civil-penalty proceedings to be held and that any affected person(s) having a valid legal interest be allowed to intervene.

Response—The request was not adopted. The alleged violator is afforded an opportunity for a hearing to present witnesses and other evidence. Such hearings are not intended to be highly structured legal proceedings but rather an informal method of accepting evidence for the case file. However, MMS agrees to maintain a listing of current and completed actions related to civil-penalty proceedings which will be available to the public. Copies of listings will be available upon request from the Offices of MMS's Regional Directors.

Subpart O—Training

Provisions contained in §§ 250.68, Training in well control, and 250.125, Safety device training, of the proposed rule published in the **Federal Register** on March 18, 1986, have been moved to a new Subpart O in the final rule. Proposed § 250.68 has been deleted and proposed § 250.125 has been modified to simply require compliance with the requirements of Subpart O.

Subpart P—Sulphur Operations

The final rule contains a new Subpart P, Sulphur Operations, which governs sulphur exploration, development, and production operations. The provisions of Subpart P require compliance with the Gulf of Mexico OCS Region Order No. 10 and with pertinent requirements of 30 CFR Part 250.

National Environmental Policy Act

The MMS prepared an EA and determined that the consolidation of the offshore operating rules will not have a significant effect on the environment and that an EIS is not required.

Executive Order 12291

As the major purpose of the rule to reduce or eliminate unnecessary burdens on lessees, it is expected to reduce costs of operating on the OCS. It is not expected to cause an increase in costs or prices to consumers, other industries, or governmental entities and, in fact, could cause a slight decrease as cost savings might be passed on.

The DOI has determined that this document does not constitute a major rule under Executive Order 12291, and therefore, a Regulatory Impact Analysis is not required.

Regulatory Flexibility Act

The DOI has also determined that this document will not have a significant economic effect on a substantial number of small entities because, in general, the entities that engage in activities offshore are not considered small due to the technical complexities and financial resources necessary to conduct such activities.

Paperwork Reduction Act

The information collection requirements contained in 30 CFR Parts 250 have been approved by the OMB under 44 U.S.C. 3504(h).

Authors

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List of Subjects

30 CFR Part 250

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

30 CFR Part 256

Administration practice and procedure, Continental shelf, Environmental protection, Government contracts, Minerals royalties, Oil and gas exploration, Oil and gas reserves, Public lands-mineral resources, Reporting and recordkeeping requirements, Surety bonds.

Date: January 28, 1988.

William D. Bettenberg,

Director, Minerals Management Service.

DERIVATION TABLE

New Section	Old Section
Subpart A—General	
250.0	250.0.
250.1	New Provision.
250.2	250.2.
250.3	New Provision.
250.4	250.10 [1].
250.5	250.11 [1].
250.6	250.13 [1].
250.7	250.18 [1].
250.8	250.31 [1].
250.9	250.32 [1].
250.10	250.12 [1].
250.10(d)	New Provision [2].
250.11	OCS Order No. 4.
250.12	250.12 [1].
250.13	250.35.
250.13(b)	New Provision.
250.14	250.53.
250.15	250.37; OCS Order No. 1.
250.16	250.58.
250.17	250.90.
250.18	250.3; OCS Order No. 12.
250.19	250.45.
250.20	250.46 [1].
250.21	250.19.
250.22	OCS Order No. 5, paragraph 1.
250.23	250.93.
250.24	250.81.
Subpart B—Exploration and Development and Production Plans	
250.30	250.34-1 and -2.
250.31	250.34-1 and -2.
250.32	250.17; OCS Order No. 11.
250.33	250.34-1 and -3(a).
250.33(d)	New Provision.
250.34	250.34-2 and -3(b).
250.34(a)(2)	New Provision.
250.34(a)(5)	New Provision.
Subpart C—Pollution Prevention and Control	
250.40	250.43; OCS Order No. 7; OCS Order No. 1, paragraph 5.
250.40(b)(1)	New Provision.

DERIVATION TABLE—Continued

New Section	Old Section
250.40(b)(5)	New Provision.
250.40(c)(1)	New Provision.
250.40(c)(2)	New Provision.
250.40(c)(3)	New Provision.
250.40(c)(4)	New Provision.
250.40(d)	New Provision.
250.41	OCS Order No. 7.
250.42	250.43; OCS Order No. 7.
250.42(b)	New Provision.
250.42(c)	New Provision.
250.42(d)	New Provision.
250.42(i)	New Provision.
250.42(j)	New Provision.
250.43	OCS Order No. 7.
250.44	250.2 [1].
250.45	250.57-1 [1].
250.46	250.57-2 [1].
Subpart D—Drilling Operations	
250.50	250.30; 250.42; 250.46.
250.51	
250.51(a)	OCS Order No. 2, paragraph 2, Alaska OCS Order.
250.51(b)	New Provision.
250.51(c)	OCS Order No. 2, paragraph 2.4.
250.51(d)	OCS Order No. 2, paragraph 2.3.
250.51(e)	250.39; 250.40; OCS Order No. 2, paragraph 4.
250.51(f)	OCS Order No. 8.
250.51(g)	OCS Order No. 5, paragraph 7.
250.51(h)	OCS Order No. 5, paragraph 5.3.
250.51(i)	OCS Order No. 5, paragraph 5.3.
250.52	OCS Order No. 2, Alaska OCS Region, paragraph 2.1.6, OCS Order No. 5, paragraph 5.4.
250.53	OCS Order No. 2, Alaska OCS Region, paragraphs 12 (a), (b), (e), and (f); OCS Order No. 5, paragraph 5.1.10.
250.54	250.41; OCS Order No. 2, paragraph 3.
250.55	OCS Order No. 2, paragraph 3.6.
250.56	250.41; OCS Order No. 2, paragraph 5.
250.57	OCS Order No. 2, paragraph 5.7.
250.58	OCS Order No. 2, paragraph 5.9.
250.59	OCS Order No. 2, paragraphs 5.2, 5.3, 5.4.1, and 5.5.
250.60	250.41; OCS Order No. 2, paragraph 6.
250.61	250.44.
250.62	250.11; OCS Order No. 2, paragraph 10.
250.63	250.41; OCS Order No. 2, paragraph 7.
250.64	250.36; OCS Order No. 2, paragraphs 1.2 and 2.
250.65	250.92.
250.66	250.38; 250.92; 250.95.
250.67	OCS Order No. 2, paragraph 8; GSS-OCS-1.
Subpart E—Well Completion Operations	
250.70	New Provision.
250.71	New Provision.
250.72	New Provision.
250.73	New Provision.
250.74	New Provision.
250.75	New Provision.
250.76	New Provision.
250.77	New Provision.
250.78	New Provision.
250.79	New Provision.
250.80	New Provision.
250.81	New Provision.
250.82	New Provision.
250.83	250.92.
250.84	New Provision.

DERIVATION TABLE—Continued

New Section	Old Section
250.85	New Provision.
250.86	New Provision.
250.87	OCS Order No. 6, paragraphs 1 and 2.
Subpart F—Well-Workover Operations	
250.90	New Provision.
250.91	New Provision.
250.92	New Provision.
250.93	New Provision.
250.94	New Provision.
250.95	New Provision.
250.96	New Provision.
250.97	New Provision.
250.98	New Provision.
250.99	New Provision.
250.100	New Provision.
250.101	New Provision.
250.102	New Provision.
250.103	250.92.
250.104	New Provision.
250.105	New Provision.
250.106	New Provision.
250.107	OCS Order No. 6, paragraphs 1 and 2.
250.108	New Provision.
Subpart G—Abandonment of Wells	
250.110	250.15; 250.44; OCS Order No. 3.
250.111	250.44; 250.92; OCS Order No. 3.
250.112	OCS Order No. 3.
250.113	OCS Order No. 1, OCS Order No. 3.
250.114	250.92; OCS Order No. 3.
Subpart H—Production Safety Systems	
250.120	OCS Order No. 5.
250.121	250.41; OCS Order No. 5, paragraph 3.
250.122	250.41(b); OCS Order No. 5, paragraph 4.
250.123	OCS Order No. 5, paragraph 5.
250.124	OCS Order No. 5, paragraphs 5.5 and 5.6.
250.125	OCS Order No. 5, paragraph 5.7 [1].
250.126	OCS Order No. 5, paragraph 2.
250.127	New Provision.
Subpart I—Platforms and Structures	
250.130	OCS Order No. 8, paragraph 1.
250.130(g)	New Provision.
250.131	OCS Order No. 8, paragraphs 2 and 3.
250.132	OCS Order No. 8, paragraphs 1.4.1, 3.2.2, 3.3, and 3.4.
250.133	OCS Order No. 8, paragraph 1.4.1.
250.134	OCS Order No. 8, paragraph 1.4.2.
250.135	OCS Order No. 8, paragraph 1.4.2.
250.136	OCS Order No. 8, paragraph 1.4.2.
250.137	OCS Order No. 8, paragraph 1.4.2.
250.138	OCS Order No. 8, paragraph 1.4.2.
250.139	OCS Order No. 8, paragraph 1.4.2.
250.140	OCS Order No. 8, paragraph 1.4.2.
250.141	OCS Order No. 8, paragraph 1.4.2.

DERIVATION TABLE—Continued

New Section	Old Section
250.142	New Provision.
250.143	OCS Order No. 3, paragraph 2.9.
250.144	OCS Order No. 8, paragraph 4.
Subpart J—Pipelines and Pipeline Rights-of-Way	
250.150	250.20; 256.8(a).
250.150(a)	New Provision.
250.150(c)	New Provision.
250.151	New Provision.
250.152	OCS Order No. 9.
250.152(a)	New Provision.
250.152(b)	New Provision.
250.152(c)	New Provision.
250.152(d)	New Provision.
250.152(f)	New Provision.
250.153	OCS Order No. 9, paragraph 1.C.
250.153(a)(2)	New Provision.
250.153(a)(3)	New Provision.
250.153(a)(4)	New Provision.
250.153(b)	New Provision.
250.153(c)	New Provision.
250.154	OCS Order No. 9, paragraphs 1.A(2) (a) and (c).
250.154(a)	New Provision.
250.154(b)(6)	New Provision.
250.154(b)(7)	New Provision.
250.154(b)(8)	New Provision.
250.154(b)(9)	New Provision.
250.154(c)	New Provision.
250.155	OCS Order No. 9, paragraph 1.E.
250.155(b)	New Provision.
250.156	New Provision.
250.157	OCS Order No. 9, paragraph 2.
250.157(a)(5)	New Provision.
250.157(b)	New Provision.
250.158	256.95; OCS Order No. 9, paragraph 1.E.
250.158(a)	New Provision.
250.158(c)	New Provision.
250.158(d)	New Provision.
250.150(f)	New Provision.
250.158(g)	New Provision.
250.158(h)	New Provision.
250.159	256.83; 256.89 [1]; 256.101.
250.160	256.92; 256.94; 256.100.
250.160(d)	New Provision.
250.161	256.85; 256.92; 256.94.
250.162	256.95.
250.163	256.97.
250.164	256.98.
Subpart K—Production Rates	
250.170	OCS Order No. 11, paragraph 1.
250.171	OCS Order No. 11, paragraphs 2 and 14.
250.171(a)	New Provision.
250.171(c)	New Provision.
250.172	250.16; OCS Order No. 11, paragraphs 3 and 4.
250.172(a)(1)	New Provision.
250.172(a)(3)	New Provision.
250.172(a)(5)	New Provision.
250.172(a)(7)	New Provision.
250.172(a)(8)	New Provision.
250.172(b)(3)	New Provision.
250.172(b)(4)	New Provision.
250.172(b)(5)	New Provision.
250.172(c)	New Provision.
250.173	250.39; OCS Order No. 11, paragraphs 5, 6, 7, and 8.
250.174	OCS Order No. 11, paragraph 9.
250.174(a)	New Provision.
250.175	250.55; OCS Order No. 11, paragraph 10; NTL 75-9 (5/13/75).
250.175(a)(2)(i)	New Provision.
250.175(a)(2)(ii)	New Provision.

DERIVATION TABLE—Continued

New Section	Old Section
250.175(c)	New Provision.
250.176	250.68; OCS Order No.11, paragraph 12.
250.177	OCS Order No. 11, paragraph 15.
250.177(b)	New Provision.
250.177(c)	New Provision.
Subpart L—Production Measurement, Commingling, and Security	
250.180	250.60; OCS Order No. 13, paragraphs 2, 3, and 4.
250.181	250.61; OCS Order No. 13, paragraph 5.
250.182	250.68; OCS Order No. 13, paragraph 6 [1].
250.183	New Provision.
Subpart M—Unitization	
250.190	250.50; 10 CFR 390.014(d).
250.191	OCS Order No. 11, paragraph 16.
250.192	250.51-1.
250.193	250.51-2.
250.194	Model Unit Agreement.
Subpart N—Remedies and Penalties	
250.200	250.80-1.
250.200(a)(2)	New Provision.
250.201	250.80-1.
250.202	250.80-1.
250.203	250.80-1.
250.204	250.80-1.
250.205	250.80-1.
250.206	250.80-2.
Subpart O—Training	
250.210	250.42.
250.211	250.42.
250.212	250.42.
Subpart P—Sulphur Operations	
250.250	New Provision.

[1] No substantive change.
[2] Codification of existing policy.

Note: The following old sections were deleted as unnecessary and redundant with no substantive change intended: 250.1, 250.4, 250.5, 250.82, and 250.96.

For the reasons set forth above, the OCS Orders are rescinded and 30 CFR Parts 250 and 256 are amended as shown:

1. The following OCS Orders are rescinded:

OCS Order No. 1, Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects for all Regions.

OCS Order No. 2, Drilling Operations, for all Regions.

OCS Order No. 3, Plugging and Abandonment of Wells, for all Regions.

OCS Order No. 4, Determination of Well Producibility, for all Regions.

OCS Order No. 5, Production Safety Systems, for all Regions.

OCS Order No. 6, Completion of Oil and Gas Wells, for the Gulf of Mexico OCS Region.

OCS Order No. 6, Procedure for Completion of Oil and Gas Wells, for the Pacific OCS Region.

OCS Order No. 7, Pollution Prevention and Control, for all Regions.

OCS Order No. 8, Platforms and Structures, for all Regions.

OCS Order No. 9, Oil and Gas Pipelines, for the Gulf of Mexico OCS Region.

OCS Order No. 9, Approval Procedure for pipelines, for the Pacific OCS Region.

OCS Order No. 10, Drilling of Twin Core Holes, for the Pacific OCS Region.

OCS Order No. 11, Oil and Gas Production Rates, Prevention of Waste, and Protection of Correlative Rights, for the Gulf of Mexico and Pacific OCS Regions.

OCS Order No. 12, Public Inspection of Records, for all Regions.

OCS Order No. 13, Production Measurement and Commingling, for the Gulf of Mexico OCS Region.

OCS Order No. 14, Approval of Suspensions of Production, for the Gulf of Mexico OCS Region.

2. Part 250 of Title 30 is revised to read as follows:

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

Subpart A—General

Sec.
250.0 Authority for information collection.
250.1 Documents incorporated by reference.
250.2 Definitions.
250.3 Performance requirements.
250.4 Jurisdiction.
250.5 Functions.
250.6 Oral approvals.
250.7 Right of use and easement.
250.8 Designation of operator.
250.9 Local agent.
250.10 Suspension of production or other operations.
250.11 Determination of well producibility.
250.12 Cancellation of leases.
250.13 Effect of production, drilling, or well reworking on lease term.
250.14 Reinjection and subsurface storage of gas.
250.15 Identification.
250.16 Reimbursement.
250.17 Information and forms.
250.18 Data and information to be made available to the public.
250.19 Accident reports.
250.20 Safe and workmanlike operations.
250.21 Access to facilities.
250.22 Best available and safest technologies.
250.23 Report of cessation of production.
250.24 Appeals, general.

Subpart B—Exploration and Development and Production Plans

Sec.
250.30 General requirements.
250.31 Preliminary activities.
250.32 Well location and spacing.
250.33 Exploration Plan.
250.34 Development and Production Plan.

Subpart C—Pollution Prevention and Control

250.40 Pollution prevention.
250.41 Inspections and reports.
250.42 Oil spill contingency plans.
250.43 Training and drills.
250.44 Definitions concerning air quality.
250.45 Facilities described in a new or revised Exploration Plan or Development and Production Plan.
250.46 Existing facilities.

Subpart D—Drilling Operations

250.50 Control of wells.
250.51 General requirements.
250.52 Welding and burning practices and procedures.
250.53 Electrical equipment.
250.54 Well casing and cementing.
250.55 Pressure testing of casing.
250.56 Blowout preventer systems and system components.
250.57 Blowout preventer systems tests, actuations, inspections, and maintenance.
250.58 Well-control drills.
250.59 Diverter systems.
250.60 Mud program.
250.61 Securing of wells.
250.62 Field drilling rules.
250.63 Supervision, surveillance, and training.
250.64 Applications for Permit to Drill.
250.65 Sundry notices and reports on wells.
250.66 Well records.
250.67 Hydrogen sulfide.
250.68 Training in well control.

Subpart E—Well-Completion Operations

250.70 General requirements.
250.71 Definition.
250.72 Equipment movement.
250.73 Emergency shutdown system.
250.74 Hydrogen sulfide.
250.75 Subsea completions.
250.76 Crew instructions.
250.77 Welding and burning practices and procedures.
250.78 Electrical requirements.
250.79 Well-completion structures on fixed platforms.
250.80 Diesel engine air intakes.
250.81 Traveling-block safety device.
250.82 Field well-completion rules.
250.83 Approval and reporting of well-completion operations.
250.84 Well-control fluids, equipment, and operations.
250.85 Blowout prevention equipment.
250.86 Blowout preventer system testing, records, and drills.
250.87 Tubing and wellhead equipment.

Subpart F—Well-Workover Operations

250.90 General requirements.
250.91 Definitions.
250.92 Equipment movement.

Sec.
250.93 Emergency shutdown system.
250.94 Hydrogen sulfide.
250.95 Subsea workovers.
250.96 Crew instructions.
250.97 Welding and burning practices and procedures.
250.98 Electrical requirements.
250.99 Well-workover structures on fixed platforms.
250.100 Diesel engine air intakes.
250.101 Traveling-block safety device.
250.102 Field well-workover rules.
250.103 Approval and reporting for well-workover operations.
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Authority: Sec. 204, Pub.L. 95-372, 92 Stat. 629 (43 U.S.C. 1334).

Subpart A—General

§ 250.0 Authority for information collection.

(a) The information collection requirements in Subpart A, General, have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3507 and assigned clearance number 1010-0030. The information is being collected to inform the Minerals Management Service (MMS) of general operations on the Outer Continental Shelf (OCS). The information is used to ensure that operations on the OCS will meet statutory and regulatory requirements, provide for safety and protection of the environment, and result in diligent exploration, development, and production on OCS leases. The requirement to respond is mandatory.

(b) The information collection requirements in Subpart B, Exploration and Development and Production Plans, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010-0049. The information is being collected to inform MMS, States, and the public of the planned exploration, development, and production activities on the OCS. The information is used to ensure that operations on the OCS will meet statutory and regulatory requirements, provide for safety and protection of the environment, and result in diligent development of leases. The requirement to respond is mandatory.

(c) The information collection requirements in Subpart C, Pollution Prevention and Control, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010-0057. The information is being collected to inform MMS of potential pollution of the environment. The information is used to identify potential sources of pollution for the purpose of preventing incidents of pollution. The requirement to respond is mandatory.

(d) The information collection requirements in Subpart D, Drilling Operations, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010-0053. The information is being collected to inform MMS of the equipment and procedures lessees plan to use in drilling activities on the OCS. The information is used to ensure that drilling operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory.

(e) The information collection requirements in Subpart E, Well-Completion Operations, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010-0067. The information is being collected to inform MMS of the equipment and procedures lessees plan to use during well-completion operations. The information is used to ensure that well-completion operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory.

(f) The information collection requirements in Subpart F, Well-

Workover Operations, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0043. The information is being collected to inform MMS of the equipment and procedures lessees plan to use during well-workover operations. The information is used to ensure that well-workover operations are safe and comply with standards to limit pollution. The requirement to respond is mandatory.

(g) The information collection requirements in Subpart G, Abandonment of Wells, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0079. The information is collected to inform MMS of the lessees' plans for temporarily abandoned wells. The requirement to respond is mandatory.

(h) The information collection requirements in Subpart H, Production Safety Systems, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0059. The information is being collected to inform MMS of the equipment and procedures lessees plan to use during the production operations. The information is used to ensure that oil and gas are produced in a manner which provides for safety of operations and protection of the environment. The requirement to respond is mandatory.

(i) The information collection requirements in Subpart I, Platforms and Structures, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0058. The information is being collected to inform MMS of the design, fabrication, and installation of platforms on the OCS. The information is used to ensure the structural integrity of platforms installed on the OCS. The requirement to respond is mandatory.

(j) The information collection requirements in Subpart J, Pipelines and Pipeline Rights-of-Way, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0050. The information is being collected to inform MMS of the location, design, and operation of pipelines on the OCS. The information is used to ensure that pipelines on the OCS will transport oil and gas in a manner which provides for safety of operations and protection of the environment. The requirement to respond is mandatory.

(k) The information collection requirements in Subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0041. The information is being collected to inform MMS of production rates for hydrocarbons produced on the OCS. The information is used to ensure that wells are produced at rates which provide for efficient production of available hydrocarbons. The requirement to respond is mandatory.

(l) The information collection requirements in Subpart L, Production Measurement, Surface Commingling, and Security, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0051. The information is being collected to inform MMS of the measurement of production, the commingling of hydrocarbons, and site-security plans and is used to ensure that produced hydrocarbons are measured and commingled in a manner which results in accurate royalty payments. The requirement to respond is mandatory.

(m) The information collection requirements in Subpart M, Unitization, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0068. The information is being collected to inform MMS of the unitization of leases. The information is used to ensure that unitization is conducted in a manner which prevents waste, conserves natural resources, and protects correlative rights. The requirement to respond is mandatory.

(n) The information collection requirements in Subpart N, Remedies and Penalties, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0038. The information is being collected to inform MMS of evidence relating to violations of provisions of the Act, leases, and MMS rules. The information is used to review violations and to determine whether the imposition of civil-penalties is appropriate. The requirement to respond is mandatory.

(o) The information collection requirements for Form MMS–330, Well (Re)Completion Report, contained in Subpart D, Drilling Operations, and Subpart E, Well-Completion Operations, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0046. The information is used to evaluate the technical, safety, and environmental factors involved in completing or recompleting a well. The obligation to respond is mandatory.

(p) The information collection requirements for Form MMS–331, Sundry Notices and Reports on Wells, contained in Subpart E, Well-Completion Operations, and Subpart F, Well-Workover Operations, and Subpart G, Abandonment of Wells, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0045. The information is used to evaluate the technical, safety, and environmental factors involved with well-completion and workover operations offshore. The obligation to respond is mandatory.

(q) The information collection requirements for Form MMS–331C, Application for Permit to Drill, contained in Subpart D, Drilling Operations, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0044. The information is used to evaluate the technical, safety, and environmental factors involved in the lessees' proposal to drill a well. The obligation to respond is mandatory.

(r) The information collection requirements for Form MMS–332, Notice of Intent/Report of Well Abandonment, contained in Subpart G, Well Abandonment, has been approved by OMB and assigned clearance number 1010–0077. The information is used to evaluate the technical, safety, and environmental factors involved during well abandonment. The obligation to respond is mandatory.

(s) The information collection requirements for Form MMS–1866, Request for Reservoir Maximum Efficient Rate, contained in Subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0018. The information is collected to provide MMS with data concerning oil or gas well completion in a rate-sensitive reservoir and is used to ensure that a requested production rate will not waste oil or gas. The obligation to respond is mandatory.

(t) The information collection requirements for Form MMS–1867, Request for Well Maximum Production Rate, contained in Subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0019. The information is collected to establish a maximum production rate for a well to prevent waste of oil and gas. The obligation to respond is mandatory.

(u) The information collection requirements for Form MMS–1868, Well Potential Test Report, contained in Subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0039. The information is collected to provide MMS with data concerning the production potential of an oil or gas well for the purpose of verifying the requested production rate. The obligation to respond is mandatory.

(v) The information collection requirements for Form MMS–1869, Quarterly Oil Well Test Report, contained in Subpart K, Production Rates, have been approved by OMB

under 44 U.S.C. 3507 and assigned clearance number 1010–0016. The information is collected to provide MMS with data concerning the status and capacity of oil wells. The information is used to verify the production capacity of each oil well. The obligation to respond is mandatory.

(w) The information collection requirements for Form MMS–1870, Semiannual Gas Well Test Report, contained in Subpart K, Production Rates, have been approved by OMB under 44 U.S.C. 3507 and assigned clearance number 1010–0017. The information is collected to provide MMS with data concerning the status and capacity of gas wells. The information is used to verify the production capacity of each gas well. The obligation to respond is mandatory.

§ 250.1 Documents incorporated by reference.

The documents listed below are incorporated by reference as requirements in this part. The Director of the Federal Register approved the incorporation by reference of these documents on [*Insert date of Federal Register approval*]. These documents are incorporated as they exist on the date of the approval, and a notice of any change in these documents will be published as a rule change in the **Federal Register**. Each document or specific portion thereof is incorporated by reference in the corresponding sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections in this part call for compliance with specific portions of the listed documents. In each instance, the applicable document is the specific edition or specific edition and supplement cited in this section. In accordance with § 250.3, Performance requirements, a lessee may comply with a later edition of a specific document incorporated by reference provided the lessee demonstrates that compliance with the later edition provides a degree of protection, safety, or performance equal to or better than that which would be achieved by compliance with the listed edition and provided the lessee obtains the prior written approval of the authorized MMS official, for such alternative compliance. The list includes the name and address of at least one organization from whom the reference document may be obtained. These documents are also available for inspection at the Office of the Federal Register Information Center, Room 8301, 1100 L Street, NW., Washington, DC 20408. In order to facilitate correlation of the text of the corresponding sections with the list of documents incorporated by reference, the documents are listed in alphanumerical order.

(a) *American Concrete Institute (ACI) Document.* The ACI document listed in this paragraph may be purchased from the American Concrete Institute, P.O. Box 19150, Detroit, Michigan 48219.

(1) ACI Standard 318–83, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–83), Incorporated by Reference at: § 250.138(b)(4)(i), (b)(6)(i), (b)(7), (b)(8)(i), (b)(9), (b)(10), (c)(3), (d)(1)(v), (d)(5), (d)(6), (d)(7), (d)(8), (d)(9), (e)(1)(i), and (e)(2)(i).

(2) ACI Standard 357–R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984, Incorporated by Reference at: §§ 250.130(g) and 250.138 (c)(2) and (c)(3).

(b) *American Institute of Steel Construction (AISC) Document.* The AISC document listed in this paragraph may be purchased from the American Institute of Steel Construction, Inc., P.O. Box 4588, Chicago, Illinois 60680.

AISC Standard S326, Specification for the Design, Fabrication and Erection of Structural Steel for Buildings, 1978 Edition, Incorporated by Reference at: § 250.137(b)(1)(ii), (c)(4)(ii), and (c)(4)(vii).

(c) *American National Standards Institute/American Society of Mechanical Engineers (ANSI/ASME) Documents.* The ANSI/ASME documents listed in this paragraph may be purchased from the American National Standards Institute, Attention Sales Department, 1430 Broadway, New York, New York 10018, and from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, New York 10017.

(1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Power Boilers including Appendices, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas, Incorporated by Reference at: § 250.123 (b)(1) and (b)(1)(i).

(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Heating Boilers including Nonmandatory Appendices A, B, C, D, E, F, H, I, and J and the Guide to Manufacturers Data Report Forms, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas, Incorporated by Reference at: § 250.123 (b)(1) and (b)(1)(i).

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Divisions 1 and 2 including Nonmandatory Appendices, 1983 Edition, with Summer and Winter 1983 and 1984 and Summer 1985 Addendas, Incorporated by Reference at: § 250.123 (b)(1) and (b)(1)(i).

(4) ANSI/ASME B 31.8–1986, Gas Transmission and Distribution Piping Systems, Incorporated by Reference at: § 250.152(a).

(5) ANSI/ASME SPPE–1–1985, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations, Incorporated by Reference at: §§ 250.121(b) and 250.126.

(6) ANSI B 16.5–1981, Pipe Flanges and Flanged Fittings, Incorporated by Reference at: § 250.152(b)(2).

(7) ANSI Z88.2–1980, Practices for Respiratory Protection, Incorporated by Reference at: § 250.67 (h)(2)(iv) and (h)(6)(i).

(d) *American Petroleum Institute (API) Documents.* The API documents listed in this paragraph may be purchased from the American Petroleum Institute, 1220 L Street, NW., Washington, DC 20005. (Paragraphs (d)(19) through (d)(46) of this section refer to the API Manual of Petroleum Measurement Standards.)

(1) API RP 2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms, Seventeenth Edition, April 1, 1987, API Stock No. 811–00200, Incorporated by Reference at: § 250.130(g).

(2) API RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes, Second Edition, June 1984, API Stock No. 811–00500, Incorporated by Reference at: § 250.51(g).

(3) API RP T–2, Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices, Revised October 1975, API Stock No. 811–13710, Incorporated by Reference at: §§ 250.210 (a) and 250.212 (a) and (c).

(4) API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Fifteenth Edition, April 1, 1986, with Supplement 1, December 1986, API Stock No. 811–03100, Incorporated by Reference at: § 250.152 (b)(1) and (b)(2).

(5) API Spec 6D, Specification for Pipeline Valves, End Closures, Connectors and Swivels, Eighteenth Edition, January 1982 with Supplement 3, July 1985, API Stock No. 811–03200, Incorporated by Reference at: § 250.152(b)(1).

(6) API RP 14B, Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems, Second Edition, November 1981 with Supplement 3, June 1986, API Stock No. 811–07160, Incorporated by Reference at: §§ 250.121(e)(4) and 250.124(a)(1)(i).

(7) API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Fourth Edition, September 1, 1986, API Stock No. 811–07180, Incorporated by Reference at: §§ 250.122(b) and (e)(2); 250.123(a), (b)(2)(i), (b)(4), (b)(5)(i), (b)(7), (b)(9)(v) and (c)(2); 250.124(a) and (a)(5); and 250.152(d).

(8) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fourth Edition, April 15, 1984, API Stock No. 811–07185, Incorporated by Reference at: § 250.122(e)(3).

(9) API RP 14F, Recommended Practice for Design and Installation of Electrical Systems

for Offshore Production Platforms, Second Edition, July 1, 1985, API Stock No. 811-07190, Incorporated by Reference at: §§ 250.53(c) and 250.123 (b)(9)(v).

(10) API RP 14C, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, Second Edition, May 1, 1986, API Stock No. 811-07194, Incorporated by Reference at: §§ 250.123(b)(8) and (b)(9)(v).

(11) API RP 14H, Recommended Practice for Use of Surface Safety Valves and Underwater Safety Valves Offshore, Second Edition, April 30, 1984, API Stock No. 811-07196, Incorporated by Reference at: § 250.122(d).

(12) API RP 500B, Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms, Second Edition, July 1973 with Supplement 2, May 1981, API Stock No. 811-06000, Incorporated by Reference at: §§ 250.53(b); 250.122(e)(4)(i), and 250.123(b)(9)(i).

(13) API Standard 2545, Method of Gaging Petroleum and Petroleum Products, October 1965, also available as ANSI/ASTM D 1085-65, API Stock No. 852-25450, Incorporated by Reference at: §§ 250.180 (f)(2)(ii).

(14) API Standard 2550, Method for Measurement and Calibration of Upright Cylindrical Tanks, First Edition, October 1965, also available as ANSI/ASTM D 1220-65, API Stock No. 852-25500, Incorporated by Reference at: 250.180 (f)(2)(i).

(15) API Standard 2551, Standard Method for Measurement and Calibration of Horizontal Tanks, First Edition, 1965, also available as ANSI/ASTM D 1410-65, API Stock No. 852-25510, Incorporated by Reference at: § 250.180(f)(2)(i).

(16) API Standard 2552, Measurement and Calibration of Spheres and Spheroids, First Edition, 1966, also available as ANSI/ASTM D 1408-65, API Stock No. 852-25520, Incorporated by Reference at: §§ 250.180(f)(2)(i).

(17) API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966, also available as ANSI/ASTM D 1406-65, API Stock No. 852-25550, Incorporated by Reference at: §§ 250.180(f)(2)(i).

(18) API RP 2556, Recommended Practice for Correcting Gage Tables for Incrustation, First Edition, August 1968, API Stock No. 852-25560, Incorporated by Reference at: § 250.180(f)(2)(i).

(19) Chapter 4, Proving Systems, First Edition, May 1978, also available as ANSI/API MPMS 4-1978, API Stock No. 852-30080, Incorporated by Reference at: §§ 250.180(c)(6)(i) and (d)(3)(iv).

(20) Chapter 5.1, Foreword, General Considerations and Scope, First Edition, November 1976, also available as ANSI/API MPMS 5.1-1976, API Stock No. 852-30101, Incorporated by Reference at: §§ 250.180(c)(6)(ii).

(21) Chapter 5.2, Measurement of Liquid Hydrocarbons by Displacement Meter Systems, First Edition, January 1977, also available as ANSI/API MPMS 5.2-1977, API Stock No. 852-30102, Incorporated by Reference at: § 250.180(c)(6)(ii).

(22) Chapter 5.3, Turbine Meters, First Edition, July 1976, API Stock No. 852-30103, Incorporated by Reference at: § 250.180(c)(6)(ii).

(23) Chapter 5.4, Instrumentation or Accessory Equipment for Liquid Hydrocarbon Metering Systems, First Edition, July 1976, also available as ANSI/API MPMS 5.4-1976, API Stock No. 852-30104, Incorporated by Reference at: § 250.180(c)(6)(ii).

(24) Chapter 5.5, Fidelity and Security of Flow Measurement Pulsed Data Transmission Systems, First Edition, June 1982, API Stock No. 852-30105, Incorporated by Reference at: § 250.180(c)(6)(ii).

(25) Chapter 6.1, LACT Systems, First Edition, February 1981, also available as ANSI/API MPMS 6.1-1981, API Stock No. 852-30121, Incorporated by Reference at: § 250.180(c)(6)(iii)(A).

(26) Chapter 6.6, Pipeline Metering Systems, First Edition, August 1981, also available as ANSI/API MPMS 6.6-1981, API Stock No. 852-30126, Incorporated by Reference at: § 250.180(c)(6)(iii)(B).

(27) Chapter 6.7, Metering Viscous Hydrocarbons, First Edition, January 1981, also available as ANSI/API MPMS 6.7-1981, API Stock No. 852-30127, Incorporated by Reference at: § 250.180(c)(6)(iii)(C).

(28) Chapter 7.2, Dynamic Temperature Determination, First Edition, June 1985, API Stock No. 852-30142, Incorporated by Reference at: § 250.180 (c)(6)(iv)(A) and (f)(2)(iii)(A).

(29) Chapter 7.3, Static Temperature Determination Using Portable Electronic Thermometers, First Edition, July 1985, API Stock No. 852-30143, Incorporated by Reference at: § 250.180 (c)(6)(iv)(B) and (f)(2)(iii)(B).

(30) Chapter 8.1, Manual Sampling of Petroleum and Petroleum Products, First Edition, October 1981, also available as ANSI/ASTM D 4057, API Stock No. 852-30161, Incorporated by Reference at: § 250.180 (c)(6)(v) and (f)(2)(iv).

(31) Chapter 8.2, Automatic Sampling of Petroleum and Petroleum Products, First Edition, April 1983, also available as ANSI/ASTM D 4177, API Stock No. 852-30162, Incorporated by Reference at: § 250.180 (c)(6)(v) and (f)(2)(iv).

(32) Chapter 9.1, Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products, First Edition, June 1981, also available as ANSI/ASTM D 1298, API Stock No. 852-30181, Incorporated by Reference at: § 250.180 (c)(6)(vi) and (f)(2)(v).

(33) Chapter 9.2, Pressure Hydrometer Test Method for Density or Relative Density, First Edition, April 1982, API Stock No. 852-30182, Incorporated by Reference at: § 250.180 (c)(6)(vi) and (f)(2)(v).

(34) Chapter 10.1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method, First Edition, April 1981, also available as ANSI/ASTM D 473, API Stock No. 852-30201, Incorporated by Reference at: § 250.180 (c)(6)(vii)(A) and (f)(2)(vi)(A).

(35) Chapter 10.2, Determination of Water in Crude Oil by the Distillation Method, First Edition, April 1981, also available as ANSI/ASTM D 4006, API Stock No. 852-30202, Incorporated by Reference at: § 250.180 (c)(6)(vii)(B) and (f)(2)(vi)(B).

(36) Chapter 10.3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), First Edition, April 1981, also available as ANSI/ASTM D 4007, API Stock No. 852-30203, Incorporated by Reference at: § 250.180 (c)(6)(vii)(C) and (f)(2)(vi)(C).

(37) Chapter 10.4 (Publ 2542), Standard Methods of Test for Water and Sediment in Crude Oils, October 1970, also available as ANSI/ASTM D 96-68, API Stock No. 825-30204, Incorporated by Reference at: § 250.180 (c)(6)(vii)(D) and (f)(2)(vi)(D).

(38) Chapter 11.1—Volume Correction Factors, Volume I, Table 5A—Generalized Crude Oils and JP-4 Correction of Observed API Gravity to API Gravity at 60 °F, and Table 6A—Generalized Crude Oils and JP-4 Correction of Volume to 60 °F Against API Gravity at 60 °F, First Edition, August 1980, API Stock No. 852-27000, Incorporated by Reference at: § 250.180 (c)(6)(viii)(A), (d)(3)(v)(B), and (f)(2)(vii).

(39) Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0-90° API Gravity Range, First Edition, August 1984, API Stock No. 852-27300, Incorporated by Reference at: § 250.180(c)(6)(viii)(B).

(40) Chapter 11.2.2, Compressibility Factors for Hydrocarbons: 0.350-0.637 Relative Density (60 °F/60 °F) and −50 °F to 140 °F Metering Temperature, Second Edition, October 1986, also available as GPA 8286-86, API Stock No. 852-27307, Incorporated by Reference at: § 250.180(c)(6)(viii)(C).

(41) Chapter 11.2.3, Water Calibration of Volumetric Provers, First Edition, 1984, API Stock No. 852-27310, Incorporated by Reference at: § 250.180(d)(3)(iv).

(42) Chapter 12.2, Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters, First Edition, September 1981, also available as ANSI/API MPMS 12.2-1981, API Stock No. 852-30302, Incorporated by Reference at: § 250.180 (c)(6)(ix), (d)(3)(v)(A), and (d)(3)(v)(C).

(43) Chapter 14.3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Second Edition, September 1985, also available as ANSI/API 2530-1985, API Stock No. 852-30343, Incorporated by Reference at: § 250.181(c)(1).

(44) Chapter 14.5, Calculation of Gross Heating Value, Specific Gravity, and Compressibility of Natural Gas Mixtures From Compositional Analysis, First Edition, January 1981, also available as AGA 2172 and ANSI/API MPMS 14.5-1981, API Stock No. 852-30345, Incorporated by Reference at: § 250.181(c)(1).

(45) Chapter 14.6, Installing and Proving Density Meters Used To Measure Hydrocarbon Liquid With Densities Between 0.3 to 0.7 gm/cc at 15.56 °C (60 °F) and Saturation Vapor Pressure, First Edition, September 1979, API Stock No. 852-30346, Incorporated by Reference at: § 250.181(c)(1).

(46) Chapter 14.8, Liquefied Petroleum Gas Measurement, First Edition, February 1983, API Stock No. 852-30348, Incorporated by Reference at: § 250.181(c)(1).

(e) *American Society for Testing and Materials (ASTM) Documents.* The ASTM documents listed below may be purchased from the American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.

(1) ASTM Standard C33–86, Standard Specification for Concrete Aggregates including Nonmandatory Appendix, 1986, Incorporated by Reference at: § 250.138(b)(4)(i).

(2) ASTM Standard C94–86b, Standard Specification for Ready-Mixed Concrete, 1986, Incorporated by Reference at: § 250.138(e)(2)(i).

(3) ASTM Standard C150–86, Standard Specification for Portland Cement, 1986, Incorporated by Reference at: § 250.138(b)(2)(i).

(4) ASTM Standard C330–87, Standard Specification for Light-weight Aggregates for Structural Concrete, 1987, Incorporated by Reference at: § 250.138(b)(4)(i).

(5) ASTM Standard C595–86, Standard Specification for Blended Hydraulic Cements, 1986, Incorporated by Reference at: § 250.138(b)(2)(i).

(f) *American Welding Society (AWS) Documents.* The AWS documents listed in this paragraph may be purchased from the American Welding Society, 550 NW. LeJeune Road, P.O. Box 351040, Miami, Florida 33135.

(1) D1.1–86, Structural Welding Code—Steel, 1986 including Commentary, Incorporated by Reference at: § 250.137(b)(1)(i).

(2) D1.4–79, Structural Welding Code—Reinforcing Steel, 1979, Incorporated by Reference at: § 250.138(e)(3)(ii).

(g) *National Association of Corrosion Engineers (NACE) Documents.* The NACE documents listed in this paragraph may be purchased from the National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218.

(1) NACE Standard MR–01–75 (1984 Editorial Revision), Material Requirements, Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment with Supplement 1 issued January 1985, Supplement 2 issued February 1985, Supplement 3 issued March 1985, Supplement 4 issued May 1985, Supplement 5 issued July 1985, Supplement 6 issued August 1985, Supplement 7 issued February 1986, and Supplement 8 issued September 1986, Incorporated by Reference at: § 250.67(l)(1), (l)(2), (l)(3), and (l)(6).

(2) NACE Standard RP–01–76 (1983 Revision), Recommended Practice, Corrosion Control of Steel, Fixed Offshore Platforms Associated with Petroleum Production, Incorporated by Reference at: § 250.137(d).

§ 250.2 Definitions.

Terms used in this part shall have the meanings given in the Act and as defined below:

"Act" means the OCS Lands Act, as amended (43 U.S.C. 1331 *et seq.*).

"Affected State" means, with respect to any program, plan, lease sale, or other activity proposed, conducted, or approved pursuant to the provisions of the Act, any State:

(1) The laws of which are declared, pursuant to section 4(a)(2) of the Act, to be the law of the United States for the portion of the OCS on which such activity is, or is proposed to be, conducted;

(2) Which is, or is proposed to be, directly connected by transportation facilities to any artificial island or installation or other device permanently or temporarily attached to the seabed;

(3) Which is receiving, or in accordance with the proposed activity will receive, oil for processing, refining, or transshipment which was extracted from the OCS and transported directly to such State by means of vessels or by a combination of means including vessels;

(4) Which is designated by the Secretary of the Interior (Secretary) as a State in which there is a substantial probability of significant impact on or damage to the coastal, marine, or human environment, or a State in which there will be significant changes in the social, governmental, or economic infrastructure, resulting from the exploration, development, and production of oil and gas anywhere on the OCS; or

(5) In which the Secretary finds that because of such activity there is, or will be, a significant risk of serious damage, due to factors such as prevailing winds and currents to the marine or coastal environment in the event of any oil spill, blowout, or release of oil or gas from vessels, pipelines, or other transshipment facilities.

"Air pollutant" means any airborne agent or combination of agents for which the Environmental Protection Agency (EPA) has established, pursuant to section 109 of the Clean Air Act, national primary or secondary ambient air quality standards.

"Analyzed geological information" means data collected under a permit or a lease which have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analysis, laboratory analysis of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

"Attainment area" means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

"Best available control technology" (BACT) means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts, and other costs. The BACT shall be verified on a case-by-case basis by the Regional Supervisor and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

"Coastal environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the terrestrial ecosystem from the shoreline inward to the boundaries of the coastal zone.

"Coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder) strongly influenced by each other and in proximity to the shorelands of the several coastal States. The coastal zone includes islands, transition and intertidal areas, salt marshes, wetlands, and beaches. The coastal zone extends seaward to the outer limit of the U.S. territorial sea and extends inland from the shorelines to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and the inward boundaries of which may be identified by the several coastal States, pursuant to the authority in section 305(b)(1) of the Coastal Zone Management Act (CZMA) of 1972.

"Competitive reservoir" means a reservoir in which there are one or more well completions on each of two or more leases from which the lessees plan future production.

"Correlative rights," when used with respect to lessees of adjacent tracts, means the right of each lessee to be afforded an equal opportunity to explore for, develop, and produce, without waste, oil or gas, or both, from a common source.

"Data" means facts and statistics or samples which have not been analyzed or processed.

"Development" means those activities which take place following discovery of minerals in paying quantities, including geophysical activity, drilling, platform construction, and operation of all onshore support facilities, and which are for the purpose of ultimately producing the minerals discovered.

"Director" means the Director of MMS of the U.S. Department of the Interior.

"District Supervisor" means the MMS officer with authority and responsibility for a district within an MMS Region.

"Eastern Gulf of Mexico" means all OCS areas in the Gulf of Mexico

deemed by the Director to be adjacent to the State of Florida.

"Emission offsets" means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan or Development and Production Plan.

"Enhanced recovery operations" means pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

"Existing facility" as used in § 250.45 is an OCS facility described in an Exploration Plan or a Development and Production Plan submitted or approved prior to June 2, 1980.

"Exploration" means the process of searching for minerals, including:

(1) Geophysical surveys where magnetic, gravity, seismic, or other systems are used to detect or imply the presence of such minerals; and

(2) Any drilling, whether on or off known geological structures, including the drilling of a well in which a discovery of oil or natural gas in paying quantities is made and the drilling of any additional delineation well after such discovery which is needed to delineate any reservoir and to enable the lessee to determine whether to proceed with development and production.

"Facility" as used in § 250.45 concerning air quality means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil or gas at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

"Facility" as used in § 250.67(b) concerning hydrogen sulfide (H_2S) means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

"Gas reservoir" means a reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

"Gas-well completion" means a well completed in a gas reservoir or in the gas-cap of an oil reservoir with an associated gas cap.

"Governor" means the Governor of a State, or the person or entity designated by, or pursuant to, State law to exercise the powers granted to such Governor pursuant to the Act.

"Human environment" means the physical, social, and economic components, conditions, and factors which interactively determine the state, condition, and quality of living conditions, employment, and health of those affected, directly or indirectly, by activities occurring on the OCS.

"Information" when used without a qualifying adjective, includes analyzed geological information, processed geological information, processed geophysical information, interpreted geological information, and interpreted geophysical information.

"Interpreted geological information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of data and analyzed geological information.

"Interpreted geophysical information" means knowledge, often in the form of schematic cross sections and maps, developed by determining the geological significance of geophysical data and processed geophysical information.

"Lease" means any form of authorization which is issued under section 8 or maintained under section 6 of the Act and which authorizes exploration for, and development and production of, minerals or the area covered by that authorization, whichever is required by the context.

"Lease term pipelines" are those pipelines owned and operated by a lessee or operator and are wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not cornering) leases of that lessee or operator.

"Lessee" means the party authorized by a lease, or an approved assignment thereof, to explore for and develop and produce the leased deposits in accordance with the regulations in this part.

"Major Federal action" means any action or proposal by the Secretary which is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act of 1969 (i.e., an action which will have a significant impact on the quality of the human environment requiring preparation of an Environmental Impact Statement pursuant to section 102(2)(C) of the National Environmental Policy Act).

"Marine environment" means the physical, atmospheric, and biological components, conditions, and factors which interactively determine the productivity, state, condition, and quality of the marine ecosystem, including the waters of the high seas, the contiguous zone, transitional and intertidal areas, salt marshes, and wetlands within the coastal zone and on the OCS.

"Maximum efficient rate" (MER) means the maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

"Maximum production rate" means the approved maximum daily rate at which oil or gas may be produced from a specified oil-well or gas-well completion.

"Minerals" includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals which are authorized by an act of Congress to be produced from "public lands" as defined in section 103 of the Federal Land Policy and Management Act of 1976.

"Nonattainment area" means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard established by EPA.

"Nonsensitive reservoir" means a reservoir in which ultimate recovery is not decreased by high reservoir production rates.

"Oil reservoir" means a reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

"Oil reservoir with an associated gas cap" means a reservoir that contains hydrocarbons in both a liquid and gaseous (two-phase) state.

"Oil-well completion" means a well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

"Operator" means the individual, partnership, firm, or corporation having control or management of operations on the leased area or a portion thereof. The operator may be a lessee, designated agent of the lessees, or holder of operating rights under an approved operating agreement.

"Outer Continental Shelf (OCS)" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in section 2 of the Submerged

Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

"Person" includes, in addition to a natural person, an association, a State, a political subdivision of a State, or a private, public, or municipal corporation.

"Pipelines" are the piping, risers, and appurtenances installed for the purpose of transporting oil, gas, sulphur, and produced waters.

"Processed geological information" means data collected under a permit or a lease which have been processed. Processing involves changing the form of data so as to facilitate interpretation. Processing operations may include, but are not limited to, applying corrections for known perturbing causes, rearranging or filtering data, and combining or transforming data elements.

"Production" means those activities which take place after the successful completion of any means for the removal of minerals, including such removal, field operations, transfer of minerals to shore, operation monitoring, maintenance, and work-over operations.

"Projected emissions" means emissions, either controlled or uncontrolled, from a source or sources.

"Right-of-way pipelines" are those pipelines which: (1) Are contained within the boundaries of a single lease or unitized leases but are not owned and operated by a lessee or operator of that lease or unit, (2) are contained within the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator, (3) are contained within the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or (4) are contained within a block(s) which is unleased.

"Regional Director" means the MMS officer with responsibility and authority for a Region within MMS.

"Regional Supervisor" means the MMS officer with responsibility and authority for operations or other designated program functions within an MMS Region.

"Routine operations" means for the purposes of Subpart F, any of the following operations conducted on a well with the tree installed: (1) cutting paraffin; (2) removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations; (3) bailing sand; (4) pressure surveys; (5) swabbing; (6) scale or corrosion treatment; (7) caliper and gauge surveys; (8) corrosion inhibitor treatment; (9) removing or replacing subsurface pumps; (10) through-tubing logging (diagnostics); (11) wireline fishing; and (12) setting and retrieving other subsurface flow-control devices.

"Sensitive reservoir" means a reservoir in which ultimate recovery is decreased by high reservoir production rates. A high reservoir production rate is one which exceeds the MER.

"Waste of oil and gas" means (1) the physical waste of oil and gas; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well(s) in a manner which causes or tends to cause a reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or (4) the inefficient storage of oil.

"Well-completion operations" means the work conducted to establish production from a well after the production-casing string has been set, cemented, and pressure-tested.

"Well-control fluid" means drilling mud, completion fluid, or workover fluid as appropriate to the particular operation being conducted.

"Workover operations" means the work conducted on wells after the initial well-completion operation for the purpose of maintaining or restoring the productivity of a well.

"Zones known to contain H_2S" means geologic formations where prior drilling operations or logging, coring, testing, or producing operations have confirmed that H_2S-bearing zones will be encountered that could potentially result in atmospheric concentrations of 20 parts per million (ppm) or more of H_2S.

"Zones where the absence of H_2S has been confirmed" means one of the following: (1) Geologic formations where prior drilling operations or logging, coring, testing, or producing operations have indicated that H_2S-bearing zones have not been encountered that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S, (2) geologic formations where analysis of produced gas samples have indicated the absence of H_2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S, or (3) an area in a geological province in which there has been no prior drilling but from prior drilling in the surrounding area, it can be shown by correlation of geological and seismic data that equivalent stratigraphic units exist with an absence of H_2S throughout the area to be drilled.

"Zones where the presence of H_2S is unknown" means geologic formations where neither the presence nor absence of H_2S has been confirmed.

§ 250.3 Performance requirements.

(a) Nothing in this part shall preclude the use of new or alternative techniques, procedures, equipment, or activities other than those prescribed in the regulations of this part; if such other techniques, procedures, equipment, or activities afford a degree of protection, safety, or performance equal to or better than that intended to be achieved by the regulations of this part, provided the lessee or right-of-way holder obtains the prior written approval of the District or Regional Supervisor, as appropriate, for the use of such new or alternative techniques, procedures, equipment, or activities.

(b) The appropriate MMS official may prescribe or approve departures from the operating requirements of the regulations of this part when such departures are necessary for the proper control of a well, the facilitation of the proper development of a lease, the conservation of natural resources, the protection of life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

§ 250.4 Jurisdiction.

(a) Subject to the supervisory authority of the Secretary, drilling and production operations, handling, measurement, transportation of production, and other operations and activities conducted pursuant to a lease or right-of-way by or on behalf of a lessee or right-of-way holder are subject to the regulations in this part and are under the jurisdiction of the Director.

(b) In the exercise of that jurisdiction, the Director is authorized and directed to act upon the requests, applications, and notices submitted under the regulations in this part to issue either written or oral orders to govern lease and right-of-way operations and to require compliance with applicable laws, regulations, and lease terms so that all operations conform to sound conservation practice and are conducted in a manner which will preserve, protect, and develop mineral resources of the OCS in a manner which is consistent with the following need to:

(1) Make such resources available to timely meet the Nation's energy needs;

(2) Balance orderly energy resource development with protection of the human, marine, and coastal environments;

(3) Ensure the public a fair and equitable return on the resources of the OCS;

(4) Preserve and maintain free enterprise competition; and

(5) Minimize or eliminate conflicts between the exploration, development, and production of oil and natural gas and the recovery of other resources such as fish and shellfish.

§ 250.5 Functions.

The Director, in accordance with the regulations in this part, shall accomplish the following:

(a) Regulate all operations conducted under a lease, right of use and easement, or right-of-way to promote orderly exploration, development, and production of mineral resources and to prevent unreasonable harm or damage to, or waste of, any natural resource (including any mineral deposits in areas leased or not leased), any life (including fish and other aquatic life), property, or the marine, coastal, or human environment.

(b) Require on all new drilling and production operations and, whenever practicable, existing operations, the use of BAST, which the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental cost of utilizing such technologies.

(c) Conduct a scheduled onsite inspection at least once a year of each offshore facility which is subject to environmental or safety regulations promulgated pursuant to the Act. The inspection shall be to determine that environmental protection equipment and safety equipment designed to prevent or ameliorate blowouts, fires, spillages, or other major accidents have been installed and are operating properly in accordance with the requirements of this part.

(d) Conduct periodic onsite inspection without advance notice to the operator of such facility as determined necessary to assure compliance with applicable regulations.

(e) Cooperate and consult with or solicit advice from affected States, executives of affected local governments, other interested parties, and relevant Departments and Agencies of the Federal Government.

(f) Identify for those activities under the jurisdiction of the Director those States which are deemed to be affected States.

§ 250.6 Oral approvals.

(a) The appropriate MMS official may give an oral approval whenever the regulations in this part require a lessee or other applicant to obtain such official's approval before commencing an operation or activity. If an oral approval is given in response to an oral request, the lessee or applicant shall confirm the oral request by submitting a written request within 72 hours of the oral approval and the MMS official shall approve that request subject to any conditions that were placed upon the oral approval. In the event a written application is given oral approval by an MMS official, the MMS official shall forward the approval and any conditions placed theron to the applicant.

(b) The appropriate MMS official may give oral orders to lessees in connection with requirements of this part whenever circumstances do not permit the time needed to prepare and issue such orders in writing. Oral orders shall be confirmed in writing by the appropriate MMS official.

§ 250.7 Right of use and easement.

(a) In addition to the rights and privileges granted to a lessee under a lease issued or maintained under the Act, the Regional Supervisor may grant a lessee, subject to conditions prescribed by the Regional Supervisor, a right of use and easement on the OCS to construct and maintain off the lease platforms, artificial islands, and all installations and other devices which are permanently or temporarily attached to the seabed and which are used for conducting exploration, development, and production activities or other operations on or off the lease which are related to such activities. Rights of use and easement on the OCS shall be issued and exercised in accordance with the provisions of this section.

(b) A right of use and easement, if on an area subject to any lease issued or maintained under the Act, shall be granted only after the holder of the lease has been notified by the applicant and afforded an opportunity to comment on the application.

(c) The Regional Supervisor shall require compliance with Subpart I and MMS approval for all platforms, artificial islands, and installations and other devices permanently or temporarily attached to the seabed as a condition of the granting of a right of use and easement under paragraph (a) of this section or as authorized under any lease issued or maintained under the Act.

(d) The right granted by a right of use and easement shall be exercised in accordance with the requirements placed upon lessees by the regulations in this part.

(e) A right of use and easement shall be exercised only in a manner which does not interfere unreasonably with operations of any lessee under a lease.

(f) Once a right of use and easement has been exercised, the right shall continue, beyond the termination of any lease on which it may be situated, as long as it can be demonstrated to the Regional Supervisor that the right of use and easement is maintained by the holder of the right and serves the purpose specified in the grant. If the right of use and easement extends beyond the termination of any lease on which the right of use and easement may be situated or on an unleased portion of the OCS, the rights of all subsequent lessees shall be subject to such right of use and easement.

§ 250.8 Designation of operator.

In all cases where operations are not conducted by an exclusive owner of record, a designation of operator shall be submitted to the Regional Supervisor prior to the commencement of operations. This designation will be accepted as authority for the operator, or the operator's local representative, to act on behalf of the lessee and to fulfill the lessee's obligations under the Act and the regulations in this part. All changes of address and any termination of the authority of the operator shall be reported immediately, in writing, to the Regional Supervisor. In case of a termination or in the event of a controversy between the lessee and the designated operator, both the lessee and the operator will be required to protect the interests of the lessor.

§ 250.9 Local agent.

When required by the Regional Supervisor or at the option of the lessee, the lessee shall designate a representative empowered to receive notices and comply with orders issued pursuant to the regulations in this part.

§ 250.10 Suspension of production or other operations.

(a) The Regional Supervisor may, on the Regional Supervisor's initiative or at the request of the lessee, suspend or temporarily prohibit production or any other operation or activity on all or any part of a lease (suspension) when the Regional Supervisor determines that such suspension is in the national interest and that the suspension is necessary as follows:

(1) To facilitate proper development of a lease including reasonable time to construct production facilities;

(2) To allow for the construction or negotiation for use of transportation facilities;

(3) To allow reasonable time to enter into a sales contract for oil or gas, or both, when good faith efforts to secure such contract(s) are made;

(4) To allow reasonable time to commence drilling operations when good faith efforts are prevented by reasons beyond the lessee's control, such as unexpected weather or unavoidable accidents; or

(5) To avoid continued operations which would result in premature abandonment of a producing well(s) or would not be economic.

(b) The Regional Supervisor may also direct or, at the request of the lessee, approve a suspension of any operation or activity, including production, because of the following:

(1) The lessee failed to comply with a provision of any applicable law, regulation, or order, or provision of a lease or permit;

(2) There is a threat of serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment;

(3) The suspension is in the interest of national security or defense;

(4) The suspension is necessary for the implementation of the requirements of the National Environmental Policy Act or to conduct an environmental analysis;

(5) The suspension is necessary to facilitate the installation of equipment necessary for safety and environmental reasons;

(6) The suspension is necessary to allow for inordinate delays encountered by the lessee in obtaining required permits or consents, including administrative or judicial challenges or appeals; or

(7) The suspension is necessary to comply with judicial decrees prohibiting production or any other operation or activity, or the permitting of those activities, effective the date set by the court for that prohibition.

(c) If provided for by lease stipulation, the Regional Supervisor shall suspend or temporarily prohibit production or any other operation or activity pursuant to a lease when such lease is in water depths of 400 to 900 meters, provided that the suspension or temporary prohibition shall be for such period of time as is necessary to complete the activities described in a Development and Production Plan approved by the Regional Supervisor in accordance with § 250.34. However, in no case shall the suspension under this paragraph be for periods of time which exceed a total of 5 years.

(d) A suspension of production pursuant to paragraph (a)(1), (2), or (3) of this section may not be issued unless a well on the lease for which the suspension is requested has been drilled and determined to be producible in paying quantities in accordance with § 250.11.

(e) Except as provided in paragraph (c) of this section, suspensions under this section may be granted for periods of time each of which shall not exceed 5 years.

(f) When the Regional Supervisor orders or approves a suspension pursuant to paragraphs (a), (b), or (c) of this section, the term of the lease shall be extended for a period of time equal to the period that the suspension is in effect, except that no lease shall be so extended when the suspension is the result of the lessee's gross negligence or willful violation of the lease or governing regulations.

(g) The Regional Supervisor may, at any time within the period prescribed for a suspension issued pursuant to paragraph (b)(2) of this section, require the lessee to submit a plan for approval, disapproval, or modification in accordance with Subpart B, Exploration and Development and Production Plans.

(h)(1) When the Regional Supervisor directs or grants a suspension pursuant to paragraph (b)(2) of this section, the Regional Supervisor may require the lessee to conduct a site-specific study(s) to identify and evaluate the cause(s) of the hazard(s) generating the suspension, the potential damage from the hazard(s), and the measures available for mitigating the hazard(s). A reasonable scope of the study(s) shall be approved or prescribed by the Regional Supervisor. The lessee shall furnish copies and all results of the study(s) to the Regional Supervisor. The cost of the study(s) shall be borne by the lessee unless the Regional Supervisor arranges for the cost of the study(s) to be borne by a party(s) other than the lessee. The Regional Supervisor shall make such results available to interested parties and to the public.

(2) On the basis of the results of the study or studies conducted in accordance with paragraph (h)(1) of this section and other information available to and identified by the Regional Supervisor, the Regional Supervisor shall require the lessee to take appropriate measures to mitigate or avoid the damage or potential damage, which resulted in the suspension or temporary prohibition of production or of any other operation or activity, as a condition for permitting the resumption of exploration, development, or production activities on the lease. The lessee shall submit, when deemed appropriate by the Regional Supervisor, a revised Exploration Plan or a revised Development and Production Plan in accordance with § 250.34 of this part. The revised plan shall incorporate the mitigating measures required by the Regional Supervisor. In choosing between alternative mitigating measures, the Regional Supervisor will balance the cost of the required measures against the reduction or potential reduction in damage or threat of damage or harm to life (including fish and other aquatic life), to property, to any mineral deposits (in areas leased or not leased), to the national security or defense, or to the marine, coastal, or human environment.

(i) The lessee must submit with a request for a suspension of production the reasons for requesting the suspension, a schedule of work leading to the commencement or restoration of production or any other operation or activity, and any other information the Regional Supervisor may require.

(j) Any suspension may be terminated at any time when the Director determines that the circumstances which justified the granting of the suspension no longer exist. When the Director terminates a suspension prior to the end of the period of time for which the suspension was originally granted, the Director shall specify in the notice of termination the reason(s) for the termination and the effective date for the termination of the suspension.

(k) Any suspension shall terminate automatically upon the commencement of production or any other suspended operation or activity.

§ 250.11 Determination of well producibility.

Upon receiving a written request from the lessee, the District Supervisor will determine whether a well is capable of producing in paying quantities (production of oil, gas, or both in quantities sufficient to yield a return in excess of the costs, after completion of the well, of producing the hydrocarbons at the wellhead.) Such a determination shall be based upon the following:

(a) A production test for oil wells shall be of at least 2 hours' duration following stabilization of flow. A deliverability test for gas wells shall be of at least 2 hours' duration following stabilization of flow or a four-point back-pressure test. The lessee shall provide the District

Supervisor a reasonable opportunity to witness all tests. Test data accompanied by the lessee's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided prior approval is obtained from the District Supervisor.

(b) In the Gulf of Mexico OCS Region, the following shall also be considered collectively as reliable evidence that a well is capable of producing oil or gas in paying quantities:

(1) A resistivity or induction electric log of the well showing a minimum of 15 feet of producible sand in one section that does not include any interval which appears to be water-saturated. In some cases, wells with less than 15 feet of producible sand in one section may be approved by the District Supervisor. All of the section counted as producible shall exhibit the following properties:

(i) Electrical spontaneous potential exceeding 20-negative millivolts beyond the shale base line. If mud conditions prevent a 20-negative millivolt reading beyond the shale base line, a gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand may be substituted.

(ii) A minimum true resistivity ratio of the producible section to the nearest clean water-bearing sand of at least 5:1.

(2) A log indicating sufficient porosity in the producible section.

(3) Sidewall cores and core analyses which indicate that the section is capable of producing oil or gas or evidence that an attempt was made to obtain such cores.

(4) A wireline formation test and/or mud-logging analysis which indicates that the section is capable of producing oil or gas, or evidence that an attempt was made to obtain such tests.

§ 250.12 Cancellation of leases.

(a)(1) The Secretary may terminate a suspension and cancel a lease as follows after notice and opportunity for a hearing when:

(i) Continued activity pursuant to the lease or permit would probably cause serious harm or damage to life (including fish and other aquatic life), property, other mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment;

(ii) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time;

(iii) The advantages of cancellation outweigh the advantages of continuing the lease or permit in force; and

(iv) The suspension has been in effect for at least 5 years, or the termination of suspension and lease cancellation are at the request of the lessee.

(2) If a lease is cancelled under this section or under Part 256 of this title, the lessee shall be entitled to compensation pursuant to the provisions of this section.

(b) Whenever an Exploration Plan is disapproved because the Regional Supervisor determines that approval of the activities called for in the plan would probably cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environment and the proposed activity cannot be modified to avoid these dangers, the Secretary, once the primary lease term has been extended continuously for a period of 5 years following the disapproval or upon request of the lessee at an earlier time, may terminate the suspension or temporary prohibition and cancel the lease, and the lessee shall be entitled to compensation pursuant to paragraph (f) of this section.

(c)(1) Where a Development and Production Plan is submitted before the subsequent approval of a Coastal Zone Management (CZM) program for an affected State, pursuant to the CZMA, and the plan is disapproved by the Regional Supervisor pursuant to § 250.34(k)(3)(ii), the following may occur:

(i) The term of the lease shall be duly extended and, at any time within 5 years after such disapproval, the lessee may reapply for approval of the same or a modified plan, and the Regional Supervisor shall approve, disapprove, or require modification of the plan in accordance with the provisions in § 250.34.

(ii) Upon expiration of the 5-year period described in paragraph (c)(1)(i) of this section or, at the Secretary's discretion, at an earlier time upon request of the lessee, if the Regional Supervisor has not approved a plan or required the lessee to submit a Development and Production Plan for approval or modification, the Secretary shall cancel the lease, and the lessee shall be entitled to compensation pursuant to paragraph (f) of this section.

(d) The lessee shall not be entitled to compensation when a lease expires.

(e) The lessee shall not be entitled to compensation when a lease is cancelled where the following circumstances exist:

(1) A Development and Production Plan submitted after approval of a State's CZM program, pursuant to the CZMA, is disapproved because the lessee does not receive concurrence by the State pursuant to section 307(c)(3)(B)(i) or (ii) of the CZMA, and the Secretary of Commerce does not make the finding authorized by section 307(c)(3)(B)(iii) of the CZMA;

(2) A lessee fails to submit a Development and Production Plan in accordance with § 250.34 or fails to comply with an approved plan;

(3) The owner of a nonproducing lease fails to comply with a provision of the Act, the lease, or the regulations issued under the Act, and the default continues for a period of 30 days after the mailing of a notice by registered letter to the lessee;

(4) A Development and Production Plan is disapproved because of a failure to demonstrate compliance with the requirements of applicable Federal law, or

(5) A producing lease is forfieted or is cancelled pursuant to section (5)(d) of the Act.

(f) Cancellation of a lease under paragraphs (a), (b), and (c) of this section shall entitle the lessee to receive such compensation as the lessee shows the Director as being equal to the lesser of the following:

(1) The fair value of the cancelled rights as of the date of cancellation, taking into account both anticipated revenues from the lease and costs reasonably anticipated on the lease, including costs of compliance with all applicable regulations and operating orders and liability for cleanup costs or damages, or both, in the case of an oil spill; or

(2) The excess, if any, over the lessee's revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for the lease and all direct expenditures made by the lessee after the date of issuance of the lease and in connection with exploration or development, or both, pursuant to the lease (plus interest on this consideration and expenditures from date of payment to date of reimbursement), except as follows:

(i) With respect to leases issued before September 18, 1978, compensation shall be equal to the amount specified in paragraph (f)(1) of this section, and

(ii) In the case of jointly held leases which are cancelled due to the failure of one or more partners to exercise due diligence, innocent party(s) shall have the right to seek damages for losses from the responsible party(s) and the right to acquire the interests of the negligent party(s) and be issued the lease in question.

§ 250.13 Effect of production, drilling, or well-reworking on lease term.

(a) Producing, drilling, or well-reworking operations on a leased area shall continue the lease in effect so long as the producing, drilling, or well-reworking operations are conducted no more than 90 days before the expiration of the primary term. A lease continued beyond its primary term by production, drilling, or well-reworking operations shall be continued in effect by production, drilling, or well-reworking operations which are commenced on or before the 90th day after the date of completion of the last production, drilling, or well-reworking operation. No time lapse in production, drilling, or well-reworking operations of greater than 90 days shall continue the lease in effect unless production or other operations on the lease have been suspended pursuant to § 250.10.

(b) Notwithstanding the limitations of paragraph (a) of this section, the Director may approve such other time periods between operations, not to exceed 180 days from the date of the last production, drilling, or well-reworking operations, or beyond 180 days where environmental conditions warrant, provided the Director determines that such lease extension is in the national interest and would be in the interest of conservation, or prevent waste and protect correlative rights.

(c) Nothing in the section obviates the necessity of obtaining approval of plans or notices required by this part.

§ 250.14 Reinjection and subsurface storage of gas.

(a) (1) The Regional Supervisor may authorize the reinjection of gas on the OCS to promote conservation of natural resources and to prevent waste when it can be shown that no undue interference with operations under existing leases will result.

(2) An application for reinjection of gas may be approved for the purpose of the following:

(i) Enhanced recovery projects,

(ii) Preventing of the flaring of casinghead gas, or

(iii) Other conservation measures approved by the Regional Supervisor.

(b) (1) The Regional Supervisor may authorize subsurface storage of gas on the OCS for later commercial benefit when it can be shown that no undue interference with operations under existing leases will result.

(2) In each case authorized in paragraph (b)(1) of this section, a storage agreement will be required, and the authorization for storage will provide for the payment of a storage fee or rental.

(c) Reinjection or storage of gas may be approved for locations on- or off-lease, provided that when gas is reinjected or stored off the lease or unit from which it was produced, royalties shall be paid at the time the gas is first produced. Gas produced from a reservoir containing both reinjected or stored gas and gas original to the reservoir shall be presumed to be made up of proportionate amounts of injected or stored gas and gas original to the reservoir in accordance with a formula approved or prescribed by the Regional Supervisor.

(d) The use of all or any part of a lease area for subsurface storage of gas shall not affect the continuance or expiration of such lease.

(e) Gas may not be stored on unleased lands unless a right of use and easement for that purpose has been approved by the Regional Supervisor in accordance with § 250.7.

§ 250.15 Identification.

(a) Platforms, structures, artificial islands, and mobile drilling units which have helicopter landing facilities shall be identified with at least one sign using letters and figures not less than 12 inches in height. Signs for units without helicopter landing facilities shall use letters and figures not less than 3 inches in height. Signs shall be affixed at a location that is visible to approaching traffic and shall contain the following information which may be abbreviated:

(1) Name of the lease operator,

(2) The area designation based on OCS Official Protraction Diagrams (except in the Pacific OCS Region),

(3) The block number (lease number in the Pacific OCS Region) in which the facility is located, and

(4) Platform, structure, or rig name.

(b) For each singly completed well, the lease number and well number shall be painted on the wellhead or on a sign affixed to the wellhead. In wells with multiple completions, each completion shall be individually identified at the wellhead. For subsea wellheads, the required sign shall be affixed to the flowline at a convenient surface location on the platform to which it is connected. All identifying signs shall be maintained in a legible condition.

§ 250.16 Reimbursement.

(a) When geological data, geophysical data, analyzed geological information, processed geological and geophysical information, reprocessed geological and geophysical information, and interpreted geological and geophysical information are submitted to MMS pursuant to the requirements of this part (whether or not retained by MMS) and upon receipt of a request for reimbursement no later than 90 days from the date of delivery and a determination by the Regional Supervisor that the requested reimbursement is proper, the lessee or third party shall be reimbursed for the reasonable costs of reproducing such data and information at the lessee's or third party's lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) When processed or reprocessed geological or geophysical information is submitted to MMS pursuant to the requirements of this part (whether retained by the Regional Supervisor or not) and upon receipt of a request for reimbursement no later than 90 days from the date of delivery and a determination by the Regional Supervisor that the requested reimbursement is proper, the lessee or third party shall be reimbursed for the reasonable costs attributable to processing and reprocessing such information (as distinguished from the cost of data acquisition) but only if the processing or reprocessing was in the form and manner of processing other than that used in the normal conduct of the lessee's business and was done at the specific request of the Regional Supervisor.

(c) Requests for reimbursement shall identify processing and reprocessing costs separate from acquisition costs.

(d) The lessee shall not be reimbursed for the costs of analyzing geological information or for interpreting geological or geophysical information.

§ 250.17 Information and forms.

(a) Information required to be submitted pursuant to the regulations in this part shall be furnished in the manner and form prescribed in the regulations in this part or as ordered by the Director. Copies of forms may be obtained from the Regional or District Supervisor and shall be filled out completely and filed punctually with the Regional or District Supervisor. Computer generated forms which are equal in size, readability, and paper quality, and which arrange the data in identical format, may be submitted in lieu of the forms available from the Regional or District Supervisor.

(b) Reports submitted on forms prescribed under this part or otherwise required by the Director shall include a copy marked "Public Information" which shall include all required information except that exempt from public disclosure in § 250.18 or otherwise exempt from public disclosure under law or regulation.

§ 250.18 Data and information to be made available to the public.

(a) Except as provided in paragraph (c) of this section or in § 252.7 of this chapter, geophysical data, processed geophysical information, reprocessed geophysical information, and interpreted geological and geophysical information, submitted at any time pursuant to the requirements of this part, shall not be available for public inspection without the consent of the lessee as long as the lease remains in effect, or for a period of 10 years after the date of submission, whichever is less, unless the Director determines that (i) the data and information are needed to unitize operations on 2 or more leases, to ensure proper plans of development for competitive reservoirs, or to promote operational safety or protection of the environment, and the data and information are shown only to persons with an interest in the issue, (ii) the geological and geophysical data and information are necessary for specific scientific or research purposes for the Government and the release of such data and information would further the nation interest without unduly damaging the competitive position of the lessee.

(b) Except as provided in paragraph (c) of this section or in § 252.7 of this chapter, geological data and analyzed geological information submitted pursuant to the requirements of this part, shall not be available for public inspection without the consent of the lessee except under one of the following conditions based on the status of the lease at the time of release of the data and information:

(1) For leases no longer in effect, the data and information will be released.

(2) For a lease in effect, and within the primary term specified in the lease, the data and information may be released 2 years after submission of the data or information or 60 days after a lease sale such that any portion of an offered block is within 50 miles of a well, whichever is later. For the purpose of this paragraph 2, the primary term specified in a lease shall be deemed to be extended for a period of time equal to the period of time for which a suspension of operations is granted pursuant to § 250.10 of this part; provided that the primary term specified in a lease shall not be deemed to be extended for a suspension of operations directed in accordance with § 250.10 (b) (1) of this part.

(3) For leases in effect and beyond the primary term specified in the lease, except as provided in paragraph (b)(2) of this section, data and information will be released 2 years after submission.

(4) For all leases, the data and information may be released if the Director determines that:

(i) The data and information are needed to unitize operations on 2 or more leases, to ensure proper plans of development for competitive reservoirs, or to promote operational safety or protection of the environment, and the data and information are shown only to persons with an interest in the issue;

(ii) The geological data and information are necessary for specific scientific or research purposes for the Government and the release of such data and information would further the national interest without unduly damaging the competitive position of the lessee.

(c) Geophysical data, geological data, processed geological and geophysical information, and interpreted geological and geophysical information collected on a lease with high-resolution systems (including, but not limited to, bathymetry, side-scan sonar, subbottom profiler, and magnetometer) in compliance with requirements concerning protection of environmental aspects of the lease may be made available to the public 60 days after submittal to the Regional Supervisor. However, unless the lessee can demonstrate to the satisfaction of the Regional Supervisor that release of the data or information would unduly damage the lessee's competitive position, the Regional Supervisor may release the data and information at an earlier time if the Regional Supervisor determines it is needed by affected States to make determinations under Subpart B, Exploration and Development and Production Plans, of this part.

(d) Data and information identified below shall not be available for public inspection without the consent of the lessee for the same periods as those provided in paragraph (b) of this section:

(1) On Form MMS–330, Well (Re) Completion Report

(i) item 1a. Type of well,

(ii) The following entries under Item 4, LOCATION OF WELL:

—At top Prod. interval reported below, and

—At total depth,

(iii) Item 18, TOTAL DEPTH, MD & TVD,

(iv) Item 19, PLUG BACK, T.D., MD & TVD,

(v) Item 20, IF MULTIPLE COMPL., HOW MANY,

(vi) Item 21, PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD),

(vii) Item 23, TYPE OF ELECTRIC AND OTHER LOGS RUN,

(viii) Item 25, CASING RECORD,

(ix) Item 26, LINER RECORD,

(x) Item 27, TUBING RECORD,

(xi) Item 28, PERFORATION RECORD,

(xii) Item 29, ACID, FRACTURE, CEMENT SQUEEZE, ETC.,

(xiii) The following entries under Item 30, PRODUCTION:

—HOURS TESTED,

—CHOKE SIZE, SEPARATOR PRESSURE-SEPARATOR TEMPERATURE,

—PROD'N. FOR TEST PERIOD: OIL—BBL., GAS—MCF., and WATER—BBL.,

—GAS-OIL RATIO—AT SEPARATOR CONDITIONS

—FLOW. TUBING PRESS.,

—CASING PRESSURE,

—CALCULATED 24-HOUR RATE:

—OIL GRAVITY-API (CORR.)

(xiv) Item 35, SUMMARY OF POROUS ZONES, and

(xv) Item 36, GEOLOGIC MARKERS.

(2) On Form MMS–331, Sundry Notices and Reports on Wells—

(i) The following entries under Item 4, LOCATION OF WELL:

—AT TOP PROD. INTERVAL; and

—AT TOTAL DEPTH; and

(ii) Item 15, PROPOSED DEPTH MD AND TVD.

(iii) Portions of Item 16 pertaining to subsurface locations and measured and true vertical depths for all markers and zones.

(iv) Item 16, DESCRIBE PROPOSED OR COMPLETED OPERATIONS.

(3) On Form MMS–331C, Application for Permit to Drill—

(i) Item 4, LOCATION OF WELL: At proposed prod. zone, and

(ii) Item 20, PROPOSED CASING AND CEMENTING PROGRAM.

(e) Directional survey data released to the owner of an adjacent lease pursuant to § 250.51(e)(5) shall not be released to the public without the consent of the lessee from whose lease the directional survey was taken.

(f) Data and information obtained from beneath unleased land as a result of a well deviation which has not been approved by the Regional Supervisor shall be available to the public.

§ 250.19 Accident reports.

(a) The lessee shall notify the District Supervisor of all serious accidents, any death or serious injury, and all fires, explosions, and blowouts connected with any activities or operations on the lease. All spills of oil or other liquid

pollutants shall be reported as described in § 250.41(b).

(b) The owner of an easement, right-of-way, or other permit shall comply with paragraph (a) of this section by notification and report submittal to the Regional Supervisor for such incidents occurring on the area covered by the easement, right-of-way, or other permit.

(c) Unless otherwise specifically ordered by the Director, all investigations conducted under the authority of sections 22(d) (1) and (2) of the Act shall be fact-finding proceedings with no civil or criminal issues and no adverse parties. The purpose of the investigation is to prepare a public report. Such investigations shall satisfy the following requirements:

(1) Any meetings shall be conducted in the appropriate MMS regional or district office or at some other convenient location determined by the panel chairperson. The chairperson may open a meeting or any part of it to the public if the chairperson determines that it would aid the panel in its work.

(2) All members of the panel shall be present at such meetings if possible. The chairperson may designate a member(s) of the panel to conduct meetings without all members present if the chairperson finds it to be appropriate.

(3) Appropriate oaths shall be administered by the chairperson or his/her designeee to all persons giving testimony.

(4) A verbatim transcript shall be made of any oral testimony.

(5) Each person giving testimony shall be allowed to have legal and/or other representative(s) present to advise or counsel when giving testimony to the panel.

(6) Only the following persons shall address questions to any person giving testimony:

(i) The panel members, the panel's legal advisors, any experts the panel deems necessary; and

(ii) The testimony transcriber.

(7) The chairperson of the panel may, if necessary, issue a subpoena to any witness or person who has knowledge of the accident pursuant to section 22(l) of the Act. A witness or a person who has knowledge of the accident may be required to attend a meeting at a place not more than 100 miles from the place where the subpoena is served.

(8) Any witness or person who has knowledge of the accident and is subpoenaed to testify under this subsection shall be entitled to be paid the same fees and mileage paid for similar services in the U.S. District Courts. The MMS shall pay fees and mileage for those persons that MMS has called if the persons so request.

(9) When the witness(es) or person(s) who has knowledge of the accident cannot appear to testify due to injury or who is not required to appear as provided in paragraph (c)(7) of this section, the panel may then move the meeting site to a location more convenient to the witness(es) or person(s), or the panel may accept a sworn written statement in lieu of oral testimony.

§ 250.20 Safe and workmanlike operations.

(a) The lessee shall perform all operations in a safe and workmanlike manner and shall maintain all equipment in a safe condition for the protection of the lease and associated facilities, the health and safety of all persons, and the preservation and conservation of property and the environment.

(b) The lessee shall immediately take all necessary precautions to control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

§ 250.21 Access to facilities.

(a) The lessee shall make available for inspection by MMS representatives, all platforms, artificial islands, and other installations located on offshore leases. For installations equipped with helicopter landing sites and refueling facilities, the lessee shall provide the use of those facilities for helicopters used by the MMS in the supervision of offshore operations.

(b) Lessee and nonlessee owners of easements, rights-of-way, or other permits shall make available at all reasonable times for inspection by MMS the area covered by the lease, easement, right-of-way, or permit, all improvements, structures, and fixtures thereon, and all records relative to the design, construction, operation, maintenance, repairs, or investigations on or with regard to such area.

(c) The lessee shall, on request, furnish food, quarters, and transportation for MMS representatives to inspect lease facilities and operations. Upon request no later than 90 days after furnishing food, quarters, and transportation, the lessee will be reimbursed for the costs incurred for the food, quarters, and transportation provided MMS representatives as determined by the Regional Director.

§ 250.22 Best available and safest technologies (BAST).

(a) The Director shall require on all new drilling and production operations and, wherever practicable, on existing operations, the use of the BAST, which the Director determines to be economically feasible, where ever failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(b) Conformance to the standards, codes, and practices referenced in this part will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified and until specific performance standards are developed by MMS and as directed by the Regional Supervisor on a case-by-case basis, the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale as to why one alternative technology was considered in place of another. This analysis shall include a discussion of the costs involved in the use of such technology and the incremental benefits to be gained.

§ 250.23 Report of cessation of production.

When a lease is in its extended term in § 256.37(b), a report shall be submitted to the District Supervisor when the last well on the lease ceases production. Such a report shall contain the number of the well and the date that the last well ceased production and shall be submitted within 15 days after the end of the first month in which no production occurs. A report is not required when production resumes within 15 days after the end of the first month in which no production occurs or when production ceases as a result of a suspension of production.

§ 250.24 Appeals, general.

Orders or decisions issued under the regulations in this part may be appealed in accordance with the provisions of Part 290 of this title. The filing of an appeal with the Director shall not suspend the requirement for compliance with an order or decision other than the payment of a civil-penalty. This requirement for compliance shall take precedence over any stay that may be granted other than a stay granted by the Secretary.

Subpart B—Exploration and Development and Production Plans

§ 250.30 General requirements.

All exploration, development, and production activities except for preliminary activities shall be conducted in accordance with an Exploration Plan or a Development and Production Plan approved by the Regional Supervisor. A proposed plan may apply to one or more leases held by an individual lessee or may be submitted by a group of lessees. The Regional Supervisor may authorize lessees to jointly submit environmental information for leases that are in the same planning area and have similar environmental conditions. Any reference in this part to a Development and Production Plan shall be considered to include the Development Operations Coordination Document used in the western Gulf of Mexico (GOM) (see § 250.34(c)).

§ 250.31 Preliminary activities.

Preliminary activities are geological, geophysical, and other surveys necessary to develop a comprehensive Exploration Plan or Development and Production Plan. Such preliminary activities are those which do not result in any physical penetration of the seabed of greater than 500 feet and which do not result in any significant adverse impact on the natural resources of the Outer Continental Shelf (OCS). The Regional Supervisor may require prior notification of the type, scope, and timing of any survey.

§ 250.32 Well location and spacing.

(a) The Regional Supervisor is authorized to approve well location and spacing programs necessary for exploration and development of a lease or reservoir giving consideration to, among other factors, the location of drilling units and platforms, geological and other reservoir characteristics, number of wells that can be economically drilled, protection of correlative rights, minimization of risk to the environment, and unreasonable interference with other uses of the OCS. Well location and spacing programs shall be determined independently for each lease or reservoir in a manner which will locate wells in the optimum structural position for the most effective production of reservoir fluids and avoid the drilling of unnecessary wells.

(b) For wells which could intersect or drain an offset property, the Regional Supervisor may require special measures to protect the rights of the lessor and objecting offset lessees.

§ 250.33 Exploration Plan.

(a) The lessee shall submit for approval an Exploration Plan which includes the following:

(1) The proposed type and sequence of exploration activities to be undertaken together with a timetable for their performance from commencement to completion.

(2) A description of the type of mobile drilling unit, platform, or artificial island to be used including a discussion of the drilling program and important safety and pollution-prevention features. In the Alaska OCS Region, lessees shall include provisions for—

(i) Drilling a relief well should a blowout occur,

(ii) Loss or disablement of a drilling unit, and

(iii) Loss or damage to support craft.

(3) A table indicating the approximate location of each proposed exploratory well, including surface locations, proposed well depths, and water depth at well sites.

(b) The lessee shall submit the following supporting information to accompany the Exploration Plan:

(1) Data and information described below which the Regional Supervisor deems necessary to evaluate geologic conditions:

(i) Current structure contour maps drawn to the top of each prospective hydrocarbon accumulation showing the approximate surface and bottomhole location of each proposed well.

(ii) Full-scale interpreted, and if appropriate, migrated Common Depth Point seismic lines intersecting at or near the primary well locations.

(iii) A time versus depth chart based on the appropriate velocity analysis in the area of interpretation.

(iv) Interpreted structure sections corresponding to each seismic line submitted in paragraph (b)(1)(ii) of this section showing the location and proposed depth of each well.

(v) A generalized stratigraphic column from the surface to total depth.

(vi) A description of the geology of the prospect.

(vii) A plat showing exploration seismic coverage of the lease.

(viii) A bathymetry map showing surface locations of proposed wells.

(ix) An analysis of seafloor and subsurface geologic and manmade hazards. Unless the lessee can demonstrate to the satisfaction of the Regional Supervisor that data sufficient to determine the presence or absence of such conditions are available, the lessee shall conduct a shallow hazards survey in accordance with the Regional Supervisor's specifications. The Regional Supervisor may require the submission of a shallow hazards report and the data upon which the analysis is based.

(2) An Oil Spill Contingency Plan (OSCP) as described in § 250.42 or reference to an approved regional plan.

(3) A discussion of the measures that have been or will be taken to satisfy the conditions of lease stipulations.

(4) A list of the proposed drilling fluids, including components and their chemical compositions, information on the projected amounts and rates of drilling fluid and cuttings discharges, and method of disposal.

(5) Information concerning the presence of hydrogen sulfide (H_2S) and the following proposed precautionary measures:

(i) A classification of the lease area as to whether it is within an area known to contain H_2S, an area where the presence of H_2S is unknown, or an area where the absence of H_2S has been confirmed as described in § 250.67 of this part and the documentation supporting the classification; and

(ii) If the classification is an area known to contain H_2S or an area where the presence of H_2S is unknown, an H_2S Contingency Plan as required in § 250.67 of this part.

(6) A detailed discussion of new or unusual technology to be employed. The lessee shall indicate which portions of the supporting information the lessee believes are exempt from disclosure under the Freedom of Information Act (FOIA) (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2). The lessee shall include a written discussion of the general subject matter of the deleted portions for transmittal to the recipients of plan copies.

(7) A brief description of the onshore facilities to be used to support the exploration activities including information as to whether the facilities are existing, proposed, or are to be expanded; a brief description of support vessels to be used and information concerning their frequency of travel; and a map showing the lease relative to the shoreline and depicting proposed transportation routes.

(8) For onshore support facilities, except in the western GOM, indicate the following:

(i) The location, size, number, and land requirements (including rights-of-way and easements) of the onshore support and storage facilities and, where possible, a timetable for the acquisition of lands and the construction or expansion of any facilities.

(ii) The estimated number of persons expected to be employed in support of

offshore, onshore, and transportation activities and, where possible, the approximate number of new employees and families likely to move into the affected area.

(iii) Major supplies, services, energy, water, or other resources within affected States necessary for carrying out the related plan.

(iv) The source, composition, frequency, and duration of emissions of air pollutants.

(9) The quantity, composition, and method of disposal of solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transportation operations.

(10) Historic weather patterns and other meteorological conditions of offshore areas including temperature, sky cover and visibility, precipitation, storm frequency and magnitude, wind direction and velocity, and freezing and icing conditions listing, where possible, the means and extremes of each.

(11) Physical oceanography including onsite direction and velocity of currents and tides, sea states, temperature, and salinity, water quality, and icing conditions, where appropriate.

(12) Onsite flora and fauna including both pelagic and benthic communities, transitory birds and mammals that may breed or migrate through the area when proposed activities are being conducted, identification of endangered and threatened species and their critical habitats that could be affected by proposed activities, and typical fishing seasons and locations of fishing activities. The results of any biological surveys required by the Regional Supervisor (including a copy of survey reports or references to previously submitted reports) should be incorporated into this discussion.

(13) Environmentally sensitive areas (onshore as well as offshore), e.g., refuges, preserves, sanctuaries, rookeries, calving grounds, and areas of particular concern identified by an affected State pursuant to the Coastal Zone Management Act (CZMA) which may be affected by the proposed activities.

(14) Onsite uses of the area based on information available, e.g., shipping, military use, recreation, boating, commercial fishing, subsistence hunting and fishing, and other mineral exploration in the area.

(15) Archaeological and cultural resources (including any cultural resource reports or survey information required by the Regional Supervisor and not previously submitted) located within the area that may be disturbed by the proposed activities.

(16) Existing and planned monitoring systems that are measuring or will measure environmental conditions and provide data and information on the impacts of activities in the geographic areas.

(17) An assessment of the direct and cumulative effects on the offshore and onshore environments expected to occur as a result of implementation of the Exploration Plan, expressed in terms of magnitude and duration, with special emphasis upon the identification and evaluation of unavoidable and irreversible impacts on the environment. Measures to minimize or mitigate impacts should be identified and discussed.

(18) Certificate(s) of coastal zone consistency as provided in 15 CFR Part 930.

(19) For each OCS facility, the lessee shall submit the information described below when it is needed to make the findings under § 250.45 of this part:

(i)(A) Projected emissions from each proposed or modified facility for each year of operation and the basis for all calculations to include (if the drilling unit has not yet been determined, the lessee shall use worst-case estimates for the type of unit proposed):

(1) For each source, the amount of the emission by air pollutant expressed in tons per year and the frequency and duration of emissions.

(2) For each facility, the total amount of emissions by air pollutant expressed in tons per year and, in addition for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source(s).

(3) A detailed description of all processes, processing equipment, and storage units, including information on fuels to be burned.

(4) A schematic drawing which identifies the location and elevation of each source.

(5) If projected emissions are based on the use of emission-reduction control technology, a description of the controls providing the information required by paragraph (b)(18)(iv) of this section.

(B) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific coast) of any State.

(ii)(A) The model(s) used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Regional Supervisor, and the results obtained through the use of the model(s). Only model(s) that has been approved by the Director may be used.

(B) The best available meteorological information and data consistent with the model(s) used stating the basis for the data and information selected.

(iii) The air quality status of any onshore area where the air quality is significantly affected (within the meaning of § 250.45 of this part) by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable to include the status of each area by air pollutant, the class of attainment area, and the air-pollution control agency whose jurisdiction covers the area identified.

(iv) The emission-reduction controls available to reduce emissions, including the source, the emission-reduction control technology, reductions to be achieved, and monitoring system the lessee proposes to use to measure emissions. The lessee shall indicate which emission-reduction control technology the lessee believes constitutes the best available control technology and the basis for that opinion.

(20) The name, address, and telephone number of an individual employee of the lessee to whom inquiries by the Regional Supervisor and the affected State(s) may be made.

(21) Such other information and data as the Regional Supervisor may require.

(c) Information and data discussed in other documents previously submitted to MMS or otherwise readily available to reviewers may be referenced. The material being referenced shall be cited, described briefly, and include a statement of where the material is available for inspection. Any material based on proprietary data which is not itself available for inspection shall not be so referenced.

(d) The Regional Director, after consultation with the Governor of the affected State(s) or the Governor's designated representative, the CZM agency of affected State(s), and the Office of Ocean and Coastal Resource Management of the National Oceanic and Atmospheric Administration (NOAA) may limit the amount of information required to be included to that necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions.

(e) The Regional Supervisor shall determine within 10 working days after receipt of the Exploration Plan whether additional information is needed. If no deficiencies are identified and the required number of copies have been received, the plan will be deemed submitted.

(f) Within 2 working days after the date an Exploration Plan has been deemed submitted, the Regional

Supervisor shall transmit by receipted mail a copy of the plan, except for those portions determined to be exempt from disclosure under the FOIA and the implementing regulations (43 CFR Part 2), to the Governor or the Governor's designated representative and the CZM agency of each affected State.

Receipt of the plan by the CZM agency initiates the State coastal zone consistency review period.

(g) In accordance with the National Environmental Policy Act (NEPA), the Regional Supervisor shall evaluate the environmental impacts of the activities described in the Exploration Plan.

(h) In the evaluation of an Exploration Plan, the Regional Supervisor shall consider written comments from the Governor of an affected State or the Governor's designated representative which are received prior to the deadline specified by the Regional Supervisor. The Regional Supervisor may consult directly with affected States regarding matters contained in the comments.

(i) Within 30 days of submission of a proposed Exploration Plan, the Regional Supervisor shall accomplish one of the following:

(1) Approve the plan;

(2) Require the lessee to modify any plan which is inconsistent with the provisions of the lease, the Act, or the regulations prescribed under the Act including air quality, environmental, safety, and health requirements; or

(3) Disapprove the plan if the Regional Supervisor determines that a proposed activity would probably cause serious harm or damage to life (including fish and other aquatic life), property, natural resources offshore including any mineral deposits (in areas leased or not leased), the national security or defense, or the marine, coastal, or human environment, and that the proposed activity cannot be modified to avoid the condition(s).

(j) The Regional Supervisor shall notify the lessee in writing of the reason(s) for disapproving an Exploration Plan or for requiring modification of a plan. For plans requiring modification, the Regional Supervisor shall also notify the lessee in writing of the conditions that must be met for plan approval.

(k)(1) The lessee may resubmit an Exploration Plan, as modified, to the Regional Supervisor in the same manner as for a new plan. Only information related to the proposed modifications need be submitted. The Regional Supervisor shall approve, disapprove, or require modification of the resubmitted plan based upon the criteria in paragraph (i) of this section within 30 days of the resubmission date.

(2) An Exploration Plan which has been disapproved pursuant to paragraph (i)(3) of this section may be resubmitted if there is a change in the conditions which caused it to be disapproved. The Regional Supervisor shall approve, require modification, or disapprove such a plan within 30 days of the resubmission date.

(l) When a State objects to a lessee's coastal zone consistency certification, the lessee shall modify the plan to accommodate the State's objection(s) and resubmit the plan to—

(1) The Regional Supervisor for review pursuant to the criteria in paragraphs (h), (i), and (j) of this section; and

(2) Through the Regional Supervisor to the State for review pursuant to the CZMA and the implementing regulations (15 CFR 930.83 and 930.84).

Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in section 307 of the CZMA and the implementing regulations (Subpart H of 15 CFR Part 930). The Regional Supervisor shall approve or disapprove a plan as resubmitted within 30 days of the resubmission date.

(m) If the Regional Supervisor disapproves an Exploration Plan, the Secretary may, subject to the provisions of section 5(a)(2)(B) of the Act and the implementing regulations in § 250.12 and 256.77 of this Chapter II, cancel the lease(s), and the lessee shall be entitled to compensation in accordance with section 5(a)(2)(c) of the Act.

(n)(1) The Regional Supervisor shall periodically review the activities being conducted under an approved Exploration Plan and may request updated information on schedules and procedures. The frequency and extent of the Regional Supervisor's review shall be based upon the significance of any changes in available information and in other onshore or offshore conditions affecting or affected by exploration activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this part, the Regional Supervisor shall require the needed revision.

(2) Revisions to an approved or pending Exploration Plan, whether initiated by the lessee or ordered by the Regional Supervisor, shall be submitted to the Regional Supervisor for approval. Only information related to the proposed revisions need be submitted. When the Regional Supervisor determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated or requires additional permits, the revisions shall be subject to all of the procedures in this section.

(o) To ensure safety and environmental protection, the Regional Supervisor may authorize or direct the lessee to conduct geological, geophysical, biological, or other surveys or monitoring programs. The lessee shall provide the Regional Supervisor, upon request, with copies of any data obtained as a result of those surveys and monitoring programs.

(p) The lessee may not drill any well until the District Supervisor's approval of an Application for Permit to Drill (APD), submitted in accordance with the requirements of § 250.64 of this part, has been received. The District Supervisor shall not approve any APD until all affected States with approved CZM programs have concurred or have been conclusively presumed to concur with the applicant's coastal zone consistency certification accompanying a plan, or the Secretary of Commerce has made the finding authorized by section 307(c)(3)(B)(iii) of the CZMA. The APD's must conform to the activities described in detail in the approved Exploration Plan and shall not be subject to a separate State coastal zone consistency review.

(q) Nothing in this section or in an approved plan shall limit the lessee's responsibility to take appropriate measures to meet emergency situations. In such situations, the Regional Supervisor may approve or require departures from an approved Exploration Plan.

§ 250.34 Development and Production Plan.

(a) The lessee shall submit for approval a Development and Production Plan which includes the following:

(1) A description of and schedule for the development and production activities to be performed including plan commencement date, date of first production, total time to complete all development and production activities, and dates and sequences for drilling wells and installing facilities and equipment.

(2) A description of any drilling vessels, platforms, pipelines, or other facilities and operations located offshore which are proposed or known by the lessee (whether or not owned or operated by the lessee) to be directly related to the proposed development, including the location, size, design, and important safety, pollution prevention, and environmental monitoring features of the facilities and operations.

(b) The lessee shall submit the following supporting information to

accompany the Development and Production Plan:

(1) Geological and geophysical (G&G) data and information, including the following:

(i) A plat showing the surface location of any proposed fixed structure or well.

(ii) A plat showing the surface and bottomhole locations and giving the measured and true vertical depths for each proposed well.

(iii) Current interpretations of relevant G&G data.

(iv) Current structure map(s) showing the surface and bottomhole location of each proposed well and the depths of expected productive formations.

(v) Interpreted structure sections showing the depths of expected productive formations.

(vi) A bathymetric map showing surface locations of fixed structures and wells or a table of water depths at each proposed site.

(vii) A discussion of seafloor conditions including a shallow hazards analysis for proposed drilling and platform sites and pipeline routes. This information shall be derived from the shallow hazards report required by § 250.139 of this part.

(2) Information concerning the presence of H_2S and proposed precautionary measures, including the following:

(i) A classification of the lease area as to whether it is within an area known to contain H_2S, an area where the presence of H_2S is unknown, or an area where the absence of H_2S has been confirmed as described in § 250.67 of this part and the documentation supporting the classification; or

(ii) If the classification is an area known to contain H_2S or an area where the presence of H_2S is unknown, an H_2S Contingency Plan as required in § 250.67 of this part.

(3) A description of the environmental safeguards to be implemented including an updated OSCP as described in § 250.42 of this part or reference to an approved plan.

(4) A discussion of the steps that have been or will be taken to satisfy the conditions of lease stipulations.

(5) A description of technology and reservoir engineering practices intended to increase the ultimate recovery of oil and gas, i.e., secondary, tertiary, or other enhanced recovery practices.

(6) A discussion of the proposed drilling and completion programs.

(7) A detailed description of new or unusual technology to be employed. The lessee shall indicate which portions of the information the lessee believes are exempt from disclosure under the FOIA (5 U.S.C. 552) and the implementing regulations (43 CFR Part 2). The lessee shall include a written discussion of the general subject matter of the deleted portions for transmittal to recipients of plan copies.

(8) A brief description of the following:

(i) The location, description, and size of any offshore, and to the maximum extent practicable, land-based operations to be conducted or contracted for as a result of the proposed activity, including the following:

(A) The acreage required within a State for facilities, rights-of-way, and easements.

(B) The means proposed for transportation of oil and gas to shore, the routes to be followed by each mode of transportation, and the estimated quantities of oil or gas, or both, to be moved along such routes.

(C) An estimate of the frequency of boat and aircraft departures and arrivals, the onshore location of terminals, and the normal routes for each mode of transportation.

(ii) A list of the proposed drilling fluids including components and their chemical compositions, information on the projected amounts and rates of drilling fluid and cuttings discharges, and method of disposal. If the information is provided in an approved Environmental Protection Agency, National Pollutant Discharge Elimination System permit, or a pending permit application, the lessee may reference these documents.

(iii) The quantities, types, and plans for disposal of other solid and liquid wastes and pollutants likely to be generated by offshore, onshore, and transport operations and, regarding any wastes which may require onshore disposal, the means of transportation to be used to bring the wastes to shore, disposal methods to be utilized, and location of onshore waste disposal or treatment facilities.

(iv) The following information on onshore support facilities, except in the western GOM:

(A) The approximate number, timing, and duration of employment of persons who will be engaged in onshore development and production activities, an approximate number of local personnel who will be employed for or in support of the development activities (classified by the major skills or crafts that will be required from local sources and estimated number of each such skill needed), and the approximate total number of persons who will be employed during the onshore construction activity and during all activities related to offshore development and production.

(B) The approximate number of people and families to be added to the population of local nearshore areas as a result of the planned development.

(C) An estimate of significant quantities of energy and resources to be used or consumed including electricity, water, oil and gas, diesel fuel, aggregate, or other supplies which may be purchased within an affected State.

(D) The types of contractors or vendors which will be needed, although not specifically identified, and which may place a demand on local goods and services.

(E) The source, composition, frequency, and duration of emissions of air pollutants.

(v) A narrative description of the existing environment with an emphasis placed on those environmental values that may be affected by the proposed action. This section shall contain a description of the physical environment of the area covered by the related plan. This portion of the plan shall include data and information obtained or developed by the lessee together with other pertinent information and data available to the lessee from other sources. The environmental information and data shall include the following, where appropriate:

(A) Archaeological and cultural resources (including any cultural resource reports or survey information required by the Regional Supervisor and not previously submitted) located within the area that may be disturbed by the proposed activities.

(B) The aquatic biota, including a description of fishery and marine mammal use of the lease and the significance of the lease, and a description of any threatened and endangered species and their critical habitat. The results of any biological surveys required by the Regional Supervisor (including a copy of survey reports or references to previously submitted reports) should be incorporated into these discussions.

(C) Environmentally sensitive areas (e.g., refuges, preserves, sanctuaries, rookeries, calving grounds, coastal habitat, beaches, and areas of particular environmental concern) which may be affected by the proposed activities.

(D) The predevelopment, ambient water-column quality and temperature data for incremental depths for the areas encompassed by the plan.

(E) The physical oceanography, including ocean currents described as to prevailing direction, seasonal variations,

and variations at different water depths in the lease.

(F) Historic weather patterns and other meteorological conditions, including storm frequency and magnitude, wave height and direction, wind direction and velocity, air temperature, visibility, freezing and icing conditions, and ambient air quality listing, where possible, the means and extremes of each.

(G) The other uses of the area known to the lessee, including military use for national security or defense, subsistence hunting and fishing, commercial fishing, recreation, shipping, and other mineral exploration or development.

(H) The existing or planned monitoring systems that are measuring or will measure impacts of activities on the environment in the planning area.

(9) An assessment of the effects on the environment expected to occur as a result of implementation of the plan, identifying specific and cumulative impacts that may occur both onshore and offshore, and the measures proposed to mitigate these impacts. Such impacts shall be quantified to the fullest extent possible including magnitude and duration and shall be accumulated for all activities for each of the major elements of the environment (e.g., water or biota).

(10) A discussion of alternatives to the activities proposed that were considered during the development of the plan including a comparison of the environmental effects.

(11) Certificate(s) of coastal zone consistency as provided in 15 CFR Part 930.

(12) For each OCS facility, such information described below needed to make the findings under § 250.45 of this part:

(i)(A) Projected emissions from each proposed or modified facility for each year of operation and basis for all calculations to include the following:

(*1*) For each source, the amount of the emission by air pollutant expressed in tons per year and frequency and duration of emissions;

(*2*) For each proposed facility, the total amount of emissions by air pollutant expressed in tons per year, the frequency distribution of total emissions by air pollutant expressed in pounds per day and, in addition for a modified facility only, the incremental amount of total emissions by air pollutant resulting from the new or modified source(s);

(*3*) A detailed description of all processes, processing equipment, and storage units, including information on fuels to be burned;

(*4*) A schematic drawing which identifies the location and elevation of each source; and

(*5*) If projected emissions are based on the use of emission-reduction control technology, a description of the controls providing the information required by paragraph (b)(9)(iv)(A) of this section.

(B) The distance of each proposed facility from the mean high water mark (mean higher high water mark on the Pacific coast) of any State.

(ii)(A) The model(s) used to determine the effect on the onshore air quality of emissions from each facility, or from other facilities when required by the Regional Supervisor, and the result obtained through the use of the model(s). Only model(s) that has been approved by the Director may be used.

(B) The best available meteorological information and data consistent with the model(s) used stating the basis for the information and data selected.

(iii) The air quality status of any onshore area where the air quality is significantly affected (within the meaning of § 250.45 of this part) by projected emissions from each facility proposed in the plan. The area should be classified as nonattainment, attainment, or unclassifiable listing the status of each area by air pollutant, the class of attainment areas, and the air pollution control agency whose jurisdiction covers the area identified.

(iv)(A) The emission-reduction controls available to reduce emissions including the source, emission-reduction control technology, reductions to be achieved, and monitoring system the lessee proposes to use to measure emissions. The lessee shall indicate which emission-reduction control technology the lessee believes constitutes the best available control technology and the basis for that opinion.

(B) The ownership of the offshore and onshore offsetting source(s) and the reduction obtainable from each offsetting source.

(13) A brief discussion of any approved or anticipated suspensions of production necessary to hold the lease(s) in an active status.

(14) The name, address, and telephone number of an individual employee of the lessee to whom inquiries by the Regional Supervisor and the affected State(s) may be directed.

(15) Such other data and information as the Regional Supervisor may require.

(c) Data and information discussed in other documents previously submitted to MMS or otherwise readily available to reviewers may be incorporated by reference. The material being incorporated shall be cited and described briefly and include a statement of where the material is available for inspection. Any material based on proprietary data which is not itself available for inspection shall not be incorporated by reference.

(d)(1) Development and Production Plans are not required for leases in the western GOM. For these leases, the lessee shall submit to the Regional Supervisor for approval a Development Operations Coordination Document with all information necessary to assure conformance with the Act, other laws, applicable regulations, lease provisions, or as otherwise needed to carry out the functions and responsibilities of the Regional Supervisor.

(2) Any information required in paragraph (d)(1) of this section shall be considered a Development and Production Plan for the purpose of references in any law, regulation, lease provision, agreement, or other document referring to the preparation or submission of a plan.

(e) The Regional Director, after consultation with the Governor(s) of the affected State(s) or the Governor's designated representative, the CZM agency of the affected State(s), and the Office of Ocean and Coastal Resource Management of NOAA may limit the amount of information required to be included in a Development and Production Plan to that necessary to assure conformance with the Act, other laws, applicable regulations, and lease provisions. In determining the information to be included in a plan, the Regional Director shall consider current and expected operating conditions together with experience gained during past operations of a similar nature in the area of proposed activities.

(f) The Regional Supervisor shall determine within 20 working days after receipt whether additional material is needed. If no deficiencies are identified and the requested number of copies have been received, the plan shall be deemed submitted.

(g) Within 5 working days after a Development and Production Plan has been deemed submitted, the Regional Supervisor shall transmit a copy of the plan, except for those portions of the plan determined to be exempt from disclosure under the FOIA and the implementing regulations (43 CFR Part 2), to the Governor or the Governor's designated representative and the CZM agency of each affected State and to the executive of each affected local government that requests a copy. The Regional Supervisor shall make copies available to appropriate Federal Agencies, interstate entities, and the

public. The plan will be available for review at the appropriate MMS Regional Public Information Office.

(h) The Governor or the Governor's designated representative and the CZM agency of each affected State and the executive of each affected local government shall have 60 days from the date of receipt of the Development and Production Plan to submit comments and recommendations to the Regional Supervisor. The executive of any affected local government must forward all recommendations to the Governor of the State prior to submitting them to the Regional Supervisor. The Regional Supervisor shall accept those recommendations from the Governor that provide for a reasonable balance between the national interest and the well-being of the citizens of the affected State. The Regional Supervisor shall explain in writing the reasons for accepting or rejecting any recommendations. In addition, any interested Federal Agency or person may submit comments and recommendations to the Regional Supervisor. All comments and recommendations shall be made available to the public.

(i) The plan will be processed in accordance with the regulations in this section and the regulations governing Federal CZM consistency procedures (15 CFR Part 930).

(j) The Regional Supervisor shall evaluate the environmental impact of the activities described in the Development and Production Plan and prepare the appropriate environmental documentation in accordance with NEPA. At least once in each planning area, as identified by the Director, other than the western and central GOM planning areas, the Director shall determine that an Environmental Impact Statement (EIS) is required. A determination by the Director that approval of a Development and Production Plan requires proceedings under NEPA shall have no effect upon the timeframe that a State has to complete its coastal zone consistency review. Copies of the draft EIS shall be transmitted to the Governor of each affected State and the executive of each affected local government that requests a copy. The Regional Supervisor shall also make copies of the draft EIS available to any appropriate Federal Agency, interstate entity, and the public.

(k) Prior to or immediately after a determination by the Director that approval of a Development and Production Plan requires that the procedures under NEPA shall commence, the Regional Supervisor may require lessees of tracts in the vicinity, for which Development and Production Plans have not been approved, to submit preliminary or final plans for their leases.

(l) No later than 60 days after the last day of the comment period provided in paragraph (h) of this section or within 60 days of the release of the final EIS describing the proposed activities, the Regional Supervisor shall accomplish the following:

(1) Approve the plan;

(2) Require modification of the plan if it is determined that the lessee has failed to make adequate provisions for safety, environmental protection, or conservation of resources including compliance with the regulations prescribed under the Act; or

(3) Disapprove the plan if one or more of the following occurs:

(i) The lessee fails to demonstrate that compliance with the requirements of the Act, provisions of the regulations prescribed under the Act, or other applicable Federal laws is possible;

(ii) State concurrence with the applicant's coastal zone consistency certification has not been received, the State's concurrence has not been conclusively presumed, or the State objects to the consistency certification, and the Secretary of Commerce does not make the determination authorized by section 307(c)(3)(B)(iii) of the CZMA;

(iii) Operations threaten national security or defense; or

(iv) Exceptional geological conditions in the lease area, exceptional resource value in the marine or coastal environment, or other exceptional circumstances exist, and all of the following:

(A) Implementation of the plan would probably cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), the national security or defense, or to the marine, coastal, or human environments.

(B) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time.

(C) The advantages of disapproving the plan outweigh the advantages of development and production.

(m) The Regional Supervisor shall notify the lessee in writing of the reason(s) for disapproving a Development and Production Plan or for requiring modification of a plan and the conditions which must be met for plan approval.

(n) The lessee may resubmit a Development and Production Plan, as modified, to the Regional Supervisor. Only information related to the proposed modifications need be submitted. Within 60 days following the 60-day comment period provided for in paragraph (h) of this section, the Regional Supervisor shall approve, disapprove, or require modification of the modified plan.

(o)(1) If a Development and Production Plan is disapproved for the sole reason that a State consistency certification has not been obtained, the Regional Supervisor shall approve the plan upon receipt of the concurrence, at the time when concurrence is conclusively presumed, or when the Secretary of Commerce makes a finding authorized by section 307(c)(3)(B)(iii) of the CZMA.

(2) If a Development and Production Plan is disapproved because a State objects to the lessee's coastal zone consistency certification, the lessee shall modify the plan to accommodate the State's objection(s) and resubmit the plan to (i) the Regional Supervisor for review pursuant to the criteria in paragraph (l) of this section; and (ii) through the Regional Supervisor, to the State for review pursuant to the CZMA and the implementing regulations (15 CFR 930.83 and 930.84). Alternatively, the lessee may appeal the State's objection to the Secretary of Commerce pursuant to the procedures described in section 307 of the CZMA and the implementing regulations (Subpart H of 15 CFR Part 930). The Regional Supervisor shall approve, disapprove, or require modification of a plan as revised within 60 days following the 60-day comment period provided for in paragraph (h) of this section.

(p) Development and Production Plans disapproved pursuant to paragraph (l)(3) of this section are subject to the provisions of section 25(h)(2) of the Act and the implementing regulations in §§ 250.12 and 256.77 of this chapter.

(q)(1) The Regional Supervisor shall periodically review the activities being conducted under an approved Development and Production Plan. The frequency and extent of the Regional Supervisor's review shall be based upon the significance of any changes in available information and onshore or offshore conditions affecting or impacted by development or production activities being conducted pursuant to the plan. If the review indicates that the plan should be revised to meet the requirements of this part, the Regional Supervisor shall require the needed revisions.

(2) Revisions to an approved or pending Development and Production Plan, whether initiated by the lessee or ordered by the Regional Supervisor, shall be submitted to the Regional

Supervisor for approval. Only information related to the proposed revisions need be submitted. When the Regional Supervisor determines that a proposed revision could result in a significant change in the impacts previously identified and evaluated requires additional permits, or proposes activities not previously identified and evaluated, the revision shall be subject to all of the procedures in this section.

(3) When any revision to an approved Development and Production Plan is proposed by the lessee, the Regional Supervisor may approve the revision if it is determined that the revision is consistent with the protection of the marine, coastal, and human environments and will lead to greater recovery of oil and natural gas; will improve the efficiency, safety, and environmental protection of the recovery operation; is the only means available to avoid substantial economic hardship to the lessee; or is otherwise not inconsistent with the provisions of the Act.

(r) Whenever the lessee fails to submit a Development and Production Plan in accordance with provisions of this section or fails to comply with an approved plan, the lease may be cancelled in accordance with sections 5 (c) and (d) of the Act and the implementing regulations in §§ 250.12 and 256.77 of this Chapter.

(s) To ensure safety and environmental protection, the Regional Supervisor may authorize or direct the lessee to conduct geological, geophysical, or other surveys. The lessee shall give the Regional Supervisor, upon request, copies of any data obtained as a result of the surveys.

(t) The lessee may not drill any well until the District Supervisor's approval of an APD, filed in accordance with the requirements of § 250.64 of this part, has been received. All applications for an APD to drill and applications to install platforms and structures, pipelines, and production equipment must conform to the activities described in detail in the approved Development and Production Plan and shall not be subject to a separate State coastal zone consistency review.

(u) Nothing in this section or approved plans shall limit the lessee's responsibility to take appropriate measures to meet emergency situations. In such situations, the Regional Supervisor may approve or require departures from an approved Development and Production Plan.

Subpart C—Pollution Prevention and Control

§ 250.40 Pollution prevention.

(a) During the exploration, development, production, and transportation of oil and gas, the lessee shall take measures to prevent unauthorized discharge of pollutants into the offshore waters. The lessee shall not create conditions which will pose unreasonable risk to the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

(1) When pollution occurs as a result of operations conducted by or on behalf of the lessee and the pollution damages or threatens to damage life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment, the control and removal of the pollution to the satisfaction of the District Supervisor shall be at the expense of the lessee. Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action shall be subject to modification when directed by the District Supervisor.

(2) If the lessee fails to control and remove the pollution, the Director, in cooperation with other appropriate Agencies of Federal, State, and local governments, or in cooperation with the lessee, or both, shall have the right to control and remove the pollution at the lessee's expense. Such action shall not relieve the lessee of any responsibility provided for by law.

(b)(1) The District Supervisor may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Supervisor may also restrict the use of components which could cause unreasonable degradation to the marine environment. No petroleum-based substances, including diesel fuel, may be added to the drilling mud system without prior approval of the District Supervisor.

(2) Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

(3) All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed, installed, and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of offshore waters shall be undertaken immediately.

(4) Curbs, gutters, drip pans, and drains shall be installed in deck areas in a manner necessary to collect all contaminants not authorized for discharge. Oil drainage shall be piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into offshore waters. All gravity drains shall be equipped with a water trap or other means to prevent gas in the sump system from escaping through the drains. Sump piles shall not be used as processing devices to treat or skim liquids but may be used to collect treated-produced water, treated-produced sand, or liquids from drip pans and deck drains and as a final trap for hydrocarbon liquids in the event of equipment upsets. Improperly designed, operated, or maintained sump piles which do not prevent the discharge of oil into offshore waters shall be replaced or repaired.

(5) On artificial islands, all vessels containing hydrocarbons shall be placed inside an impervious berm or otherwise protected to contain spills. Drainage shall be directed away from the drilling rig to a sump. Drains and sumps shall be constructed to prevent seepage.

(6) Disposal of equipment, cables, chains, containers, or other materials into offshore waters is prohibited.

(c) Materials, equipment, tools, containers, and other items used in the Outer Continental Shelf (OCS) which are of such shape or configuration that they are likely to snag or damage fishing devices shall be handled and marked as follows:

(1) All loose material, small tools, and other small objects shall be kept in a suitable storage area or a marked container when not in use and in a marked container before transport over offshore waters;

(2) All cable, chain, or wire segments shall be recovered after use and securely stored until suitable disposal is accomplished;

(3) Skid-mounted equipment, portable containers, spools or reels, and drums shall be marked with the owner's name prior to use or transport over offshore waters; and

(4) All markings must clearly identify the owner and must be durable enough to resist the effects of the environmental conditions to which they may be exposed.

(d) Any of the items described in paragraph (c) of this section that are lost overboard shall be recorded on the facility's daily operations report, as appropriate, and reported to the District Supervisor.

§ 250.41 Inspections and reports.

(a) Drilling and production facilities shall be inspected daily or at intervals approved or prescribed by the District Supervisor to determine if pollution is occurring. Necessary maintenance or repairs shall be made immediately. Records of such inspections and repairs shall be maintained at the facility or at a nearby manned facility for 2 years.

(b) Pollution response equipment shall be inspected at least monthly. Records of such inspections shall be kept for at least 2 years at a site designated in the Oil Spill Contingency Plan (OSCP).

(c) All spills of oil and liquid pollutants, including pipeline spills, spills onto the surface of sea ice, and spills penetrating the surface of an artificial island, shall be reported orally to the District Supervisor. Spills of more than 1 barrel shall be confirmed in writing. Such written confirmation shall be received by the District Supervisor by the 15th day after the spillage has been stopped. All reports shall include the cause, location, volume of spill, and remedial action taken. Reports of spills of more than 50 barrels shall include information on the sea state, meteorological conditions, size, and appearance of the slick.

(1) Spills shall be reported orally within the following time limits:

(i) Within 12 hours, if spills are 1 barrel or less; and

(ii) Without delay, if spills are more than 1 barrel.

(2) Lessees shall notify the responsible party and the District Supervisor of observed pollution resulting from operations other than those conducted by the lessee.

§ 250.42 Oil spill contingency plans.

The lessee shall submit an OSCP for approval by the Regional Supervisor with or prior to submitting an Exploration Plan or a Development and Production Plan. If an OSCP covering the area, such as a regional plan, has already been approved, it may be referred to in the Exploration Plan or the Development and Production Plan. An OSCP shall be reviewed and updated annually, and all modifications of the OSCP shall be submitted to the Regional Supervisor for approval. The OSCP shall contain the following:

(a) Oil spill trajectory analyses which are specific to the area of operations shall be referenced and summarized. The summaries shall specify those environmentally sensitive areas which may be impacted and strategies to be used for their protection.

(b) Identification of response equipment and response times together with materials, support vessels, and procedures to be employed in responding to continuous oil discharges (e.g., well blowout) and spills of short duration and limited maximum volume (e.g., tank overflows, hose failures). Response equipment and strategies shall be suitable for anticipated environmental conditions in the area of operations.

(c) A dispersant-use plan including an inventory of the dispersants which might be proposed for use, a summary of toxicity data for each dispersant, a description of the types of oil on which each dispersant is effective, a description of application equipment and procedures, and an outline of the procedures to be followed in obtaining approval for dispersant-use.

(d) Provisions for inspecting and maintaining response equipment.

(e) Establishment of procedures for the purpose of early detection and timely notification of an oil spill, including a current list of names, telephone numbers, and addresses of the responsible persons and alternates who are to receive notification of an oil spill and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

(f) An inventory of applicable equipment, materials, and supplies which are available locally and regionally.

(g) Well-defined and specific actions to be taken after discovery of an oil spill including the following:

(1) Designation (by name or position) of an oil spill response operating team comprised of trained personnel available within a specified response time and a description of the training that such personnel will receive,

(2) Designation (by name or position) of a trained oil spill response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations, and

(3) A planned location for an oil spill response operations center and a reliable communications system for directing the coordinated overall response operations.

(h) Provisions for disposal of recovered oil, oil-contaminated material, and other oily wastes.

(i) Provisions for monitoring and predicting spill movement.

(j) In the Alaska OCS Region only, provisions for ignition of an uncontrollable oil spill and the guidelines to be followed in making the decision to ignite.

§ 250.43 Training and drills.

(a) The lessee shall ensure that the oil spill response operating team is provided with hands-on training classes at least annually in the deployment and operation of the pollution control equipment to which they are assigned. The personnel responsible for supervising the oil spill response operations shall be knowledgeable about the location and intended use of available response equipment, spill reporting procedures, and deployment strategies for the facilities under their jurisdiction. Such supervisory personnel shall be trained in directing the deployment and use of all response equipment. The lessee shall retain, at the site designated in the OSCP, course-completion certificates or attendance records issued by the organization providing the instructions. These records shall be made available to any authorized MMS representative upon request.

(b) Drills for familiarization with pollution-control equipment and operational procedures shall be held when the equipment is placed initially and at least once every 12 months by the lessee or a contractor serving the lessee. The personnel identified as the oil spill response operating team in the OSCP shall participate in these drills. The drills shall simulate conditions in the area of operations and shall include deployment and operation of equipment. A time schedule for familiarization drills with a list of equipment to be deployed shall be submitted to the Regional Supervisor. The schedule shall provide sufficient advance notice to allow MMS personnel to witness any of the scheduled drills. Drill conditions, results, and the names of the participants in the drill shall be recorded, and the records shall be maintained for 2 years at a site designated in the OSCP and made available to MMS personnel. The Regional Supervisor may initiate unscheduled drills and may require an increase in the frequency or a change in the location of the drills, equipment to be deployed, or deployment procedures and strategies. The Regional Supervisor will evaluate the results of drills and advise the lessee of any necessary changes in response equipment, procedures, or strategies.

§ 250.44 Definitions concerning air quality.

For purposes of §§ 250.45 and 250.46 of this part:

"Air pollutant" means any combination of agents for which the Environmental Protection Agency (EPA) has established, pursuant to section 109

of the Clean Air Act, national primary or secondary ambient air quality standards.

"Attainment area" means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) not to exceed any primary or secondary ambient air quality standards established by EPA.

"Best available control technology" (BACT) means an emission limitation based on the maximum degree of reduction for each air pollutant subject to regulation, taking into account energy, environmental and economic impacts, and other costs. The BACT shall be verified on a case-by-case basis by the Regional Supervisor and may include reductions achieved through the application of processes, systems, and techniques for the control of each air pollutant.

"Emission offsets" means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan or Development and Production Plan.

"Existing facility" is an OCS facility described in an Exploration Plan or a Development and Production Plan submitted or approved prior to June 2, 1980.

"Facility" means any installation or device permanently or temporarily attached to the seabed which is used for exploration, development, and production activities and which emits or has the potential to emit any air pollutant from one or more sources. All equipment directly associated with the installation or device shall be considered part of a single facility if the equipment is dependent on, or affects the processes of, the installation or device. During production, multiple installations or devices will be considered to be a single facility if the installations or devices are directly related to the production of oil or gas at a single site. Any vessel used to transfer production from an offshore facility shall be considered part of the facility while physically attached to it.

"Nonattainment area" means, for any air pollutant, an area which is shown by monitored data or which is calculated by air quality modeling (or other methods determined by the Administrator of EPA to be reliable) to exceed any primary or secondary ambient air quality standard established by EPA.

"Projected emissions" means emissions, either controlled or uncontrolled, from a source(s).

"Source" means an emission point. Several sources may be included within a single facility.

"Temporary facility" means activities associated with the construction of platforms offshore or with facilities related to exploration for or development of offshore oil and gas resources which are conducted in one location for less than 3 years.

"Volatile organic compound" (VOC) means any organic compound which is emitted to the atmosphere as a vapor. The unreactive compounds are exempt from the above definition.

§ 250.45 Facilities described in a new or revised Exploration Plan or Development and Production Plan.

(a) *New plans.* All Exploration Plans and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section, and the lessee shall comply with the requirements of this section as necessary.

(b) *Applicability of § 250.45 to existing facilities.* (1) The Regional Supervisor may review any Exploration Plan or Development and Production Plan to determine whether any facility described in the plan should be subject to review under this section and has the potential to significantly affect the air quality of an onshore area. To make these decisions, the Regional Supervisor shall consider the distance of the facility from shore, the size of the facility, the number of sources planned for the facility and their operational status, and the air quality status of the onshore area.

(2) For a facility identified by the Regional Supervisor in paragraph (b)(1) of this section, the Regional Supervisor shall require the lessee to refer to the information required in §§ 250.33(a)(22) or 250.34(a)(14) of this part and to submit only that information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall submit this information within 120 days of the Regional Supervisor's determination or within a longer period of time at the discretion of the Regional Supervisor. The lessee shall comply with the requirements of this section as necessary.

(c) *Revised facilities.* All revised Exploration Plans and Development and Production Plans shall include the information required to make the necessary findings under paragraphs (d) through (i) of this section. The lessee shall comply with the requirements of this section as necessary.

(d) *Exemption formulas.* To determine whether a facility described in a new, modified, or revised Exploration Plan or Development and Production Plan is exempt from further air quality review, the lessee shall use the highest annual-total amount of emissions from the facility for each air pollutant calculated in §§ 250.33(a)(22)(i)(A) or 250.34(a)(14)(i)(A) of this part and compare these emissions to the emission exemption amount "E" for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for carbon monoxide (CO); and $E=33.3D$ for total suspended particulates (TSP), sulphur dioxide (SO_2), nitrogen oxides (NO_x), and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the proposed facility from the closest onshore area of a State expressed in statute miles). If the amount of these projected emissions is less than or equal to the emission exemption amount "E" for the air pollutant, the facility is exempt from further air quality review required under paragraphs (e) through (i) of this section.

(e) *Significance levels.* For a facility not exempt under paragraph (d) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether the projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS: AIR POLLUTANT CONCENTRATIONS ($\mu g/m^3$)

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	25	.....	.....
TSP	1	5	.....	.....	.....
NO_2	1	.....	.....	.....	.....
CO	.....	.....	500	.....	2,000

(f) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under paragraph (e) of this section for that air pollutant, shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(g) *Controls required.* (1) The projected emissions of any air pollutant other than VOC from any facility, except a temporary facility, which

significantly affect the quality of a nonattainment area, shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(2) The projected emissions of any air pollutant other than VOC from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i) Except for temporary facilities, the lessee also shall use an approved air quality model to determine whether the emissions of TSP or SO_2 that remain after the application of BACT cause the following maximum allowable increases over the baseline concentrations established in 40 CFR 52.21 to be exceeded in the attainment or unclassifiable area:

MAXIMUM ALLOWABLE CONCENTRATION INCREASES ($\mu G/M^3$)

Air pollutant	Averaging times		
	Annual mean [1]	24-hour maximum	3-hour maximum
Class I:			
TSP	5	10	
SO_2	2	5	25
Class II:			
TSP	19	37	
SO_2	20	91	512
Class III:			
TSP	37	75	
SO_2	40	182	700

[1] For TSP—geometric; For SO_2—arithmetic.

No concentration of an air pollutant shall exceed the concentration permitted under the national secondary ambient air quality standard or the concentration permitted under the national primary air quality standard, whichever concentration is lowest for the air pollutant for the period of exposure. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one onshore location.

(ii) If the maximum allowable increases are exceeded, the lessee shall apply whatever additional emission controls are necessary to reduce or offset the remaining emissions of TSP or SO_2 so that concentrations in the onshore ambient air of an attainment or unclassifiable area do not exceed the maximum allowable increases.

(3)(i) The projected emissions of VOC from any facility, except a temporary facility, which significantly affect the onshore air quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(ii) The projected emissions of VOC from any facility which significantly affect the onshore air quality of an attainment area shall be reduced through the application of BACT.

(4)(i) If projected emissions from a facility significantly affect the onshore air quality of both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to projected emissions significantly affecting a nonattainment area shall apply.

(ii) If projected emissions from a facility significantly affect the onshore air quality of more than one class of attainment area, the lessee must reduce projected emissions to meet the maximum allowable increases specified for each class in paragraph (g)(2)(i) of this section.

(h) *Controls required on temporary facilities.* The lessee shall apply BACT to reduce projected emissions of any air pollutant from a temporary facility which significantly affect the air quality of an onshore area of a State.

(i) *Emission offsets.* When emission offsets are to be obtained, the lessee must demonstrate that the offsets are equivalent in nature and quantity to the projected emissions that must be reduced after the application of BACT; a binding commitment exists between the lessee and the owner or owners of the source or sources; the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's offshore operations.

(j) *Review of facilities with emissions below the exemption amount.* If, during the review of a new, modified, or revised Exploration Plan or Development and Production Plan, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether emission control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(k) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(l) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

§ 250.46 Existing facilities.

(a) *Process leading to review of an existing facility.* (1) An affected State may request that the Regional Supervisor supply basic emission data from existing facilities when such data are needed for the updating of the State's emission inventory. In submitting the request, the State must demonstrate that similar offshore and onshore facilities in areas under the State's jurisdiction are also included in the emission inventory.

(2) The Regional Supervisor may require lessees of existing facilities to submit basic emission data to a State submitting a request under paragraph (a)(1) of this section.

(3) The State submitting a request under paragraph (a)(1) of this section may submit information from its emission inventory which indicates that emissions from existing facilities may be significantly affecting the air quality of the onshore area of the State. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the facility is not significantly affecting the air quality of the State.

(4) The Regional Supervisor shall evaluate the information submitted under paragraph (a)(3) of this section and shall determine, based on the basic emission data, available meteorological data, and the distance of the facility or facilities from the onshore area, whether any existing facility has the potential to significantly affect the air quality of the onshore area of the State.

(5) If the Regional Supervisor determines that no existing facility has the potential to significantly affect the air quality of the onshore area of the State submitting information under paragraph (a)(3) of this section, the

Regional Supervisor shall notify the State of and explain the reasons for this finding.

(6) If the Regional Supervisor determines that an existing facility has the potential to significantly affect the air quality of an onshore area of the State submitting information under paragraph (a)(3) of this section, the Regional Supervisor shall require the lessee to refer to the information requirements under § 250.33(a)(22) or 250.34(a)(14) of this part and submit only that information required to make the necessary findings under paragraphs (b) through (e) of this section. The lessee shall submit this information within 120 days of the Regional Supervisor's determination or within a longer period of time at the discretion of the Regional Supervisor. The lessee shall comply with the requirements of this section as necessary.

(b) *Exemption formulas.* To determine whether an existing facility is exempt from further air quality review, the lessee shall use the highest annual total amount of emissions from the facility for each air pollutant calculated in § 250.33(a)(22)(i)(A) or 250.34(a)(14)(i)(A) of this part and compare these emissions to the emission exemption amount "E" for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for CO; and $E=33.3D$ for TSP, SO_2, NO_X, and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the facility from the closest onshore area of the State expressed in statute miles). If the amount of projected emissions is less than or equal to the emission exemption amount "E" for the air pollutant, the facility is exempt for that air pollutant from further air quality review required under paragraphs (c) through (e) of this section.

(c) *Significance levels.* For a facility not exempt under paragraph (b) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS: AIR POLLUTANT CONCENTRATIONS ($\mu G/M^3$)

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	.....	25	.....
TSP	1	5	.....	.....	.....
NO_2	1	.....	.....	.....	.....
CO	.....	.....	500	.....	2,000

(d) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance levels determined under paragraph (c) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (b) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(e) *Controls required.* (1) The projected emissions of any air pollutant which significantly affect the air quality of an onshore area shall be reduced through the application of BACT.

(2) The lessee shall submit a compliance schedule for the application of BACT. If it is necessary to cease operations to allow for the installation of emission controls, the lessee may apply for a suspension of operations under the provisions of § 250.10 of this part.

(f) *Review of facilities with emissions below the exemption amount.* If, during the review of the information required under paragraph (a)(6) of this section, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(g) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility following the installation of emission controls. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(h) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

Subpart D—Drilling Operations

§ 250.50 Control of wells.

The lessee shall take necessary precautions to keep its wells under control at all times. The lessee shall, utilize the best available and safest drilling technology in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick. The lessee shall utilize personnel who are trained and competent and shall utilize and maintain equipment and materials necessary to assure the safety and protection of personnel, equipment, natural resources, and the environment.

§ 250.51 General requirements.

(a) *Fitness of drilling unit.* (1) Drilling units shall be capable of withstanding the oceanographic, meteorological, and ice conditions for the proposed season and location of operations.

(2) Prior to commencing operation, drilling units shall be available for complete inspection by the District Supervisor.

(3) The lessee shall provide information and data on the fitness of the drilling unit to perform the proposed drilling operation. The information shall be submitted with or prior to the submission of Form MMS-331C, Application for Permit to Drill (APD), in accordance with § 250.64. The District Supervisor may require the submission of a third-party review of the design of drilling units which are of a unique design and/or not proven for use in the proposed environment if the District Supervisor believes that the information submitted by the lessee is insufficient to demonstrate suitability of the unit for use at the proposed drill site. A design Certified Verification Agent approved in accordance with § 250.133 of this part shall be used for any required third-party review.

(b) *Drilling unit safety devices.* (1) No later than [insert date 1 year from the effective date of these regulations], all drilling units shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the driller's report.

(2) No later than [insert 1 year after the effective date of these regulations], diesel-engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either

remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

(c) *Oceanographic, meteorological, and drilling unit performance data.* Where such information is not otherwise readily available, upon request of the District Supervisor, lessees shall collect and report oceanographic, meteorological, and drilling unit performance data, and monitor ice conditions, if applicable, during the period of operations. The type of information to be collected and reported will be determined by the District Supervisor in the interests of safe conduct of operations and the structural integrity of the drilling unit.

(d) *Foundation requirements.* When the lessee fails to provide sufficient information pursuant to §§ 250.33 and 250.34 of this part to support a determination that the seafloor is capable of supporting a specific bottom-founded drilling unit under the site-specific soil and oceanographic conditions, the District Supervisor may require that additional surveys and soil borings be performed and the results be submitted for review and evaluation by the District Supervisor before approval is granted for commencing drilling operations.

(e) *Tests, surveys, and samples.* (1) The lessee shall conduct tests, obtain well and mud logs or surveys, and take samples to determine the reservoir energy; the presence, quantity, and quality of oil, gas, sulphur, and water; and the amount of pressure in the formations penetrated. The lessee shall take formation samples or cores to determine the identity, fluid content, and characteristics of any penetrated formation in accordance with requirements approved or prescribed by the District Supervisor.

(2) Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 1,000 feet during the normal course of drilling. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 100 feet in all portions of the hole when angle-changes are planned.

(3) On both vertical and directionally drilled wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 500 feet prior to or upon setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be prepared with the interval shown from the bottom of the conductor casing or, in the absence of conductor casing, from the bottom of the drive or structural casing to total depth. In calculating all surveys, a correction from the true north to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey or a composite measurement-while-drilling (MWD) directional survey including a listing of the directionally computed inclinations and azimuths on a well classified as vertical will be acceptable as fulfilling the applicable requirements of this paragraph. In the event a composite MWD survey is run, a multishot survey shall be obtained at each casing point in order to confirm the MWD results.

(4) Wells are classified as vertical if the calculated average of inclination readings weighted by the respective interval lengths between readings from surface to drilled depth does not exceed 3 degrees from the vertical. When the calculated average inclination readings weighted by the length of the respective interval between readings from the surface to drilled depth exceeds 3 degrees, the well is classified as directional.

(5) The Regional Supervisor at the request of a holder of an adjoining lease may, for the protection of correlative rights, furnish a copy of the directional survey for a well drilled within 500 feet of the adjacent lease to that leaseholder.

(f) *Fixed drilling platforms.* Applications for installation of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with the provisions of Subpart I, Platforms and Structures, of this part. Mobile drilling units which have their jacking equipment removed or have been otherwise immobilized are classified as fixed drilling platforms.

(g) *Crane operations.* Cranes installed on fixed drilling platforms shall be operated and maintained in accordance with the provisions of American Petroleum Institute (API) Recommended Practice (RP) for Operation and Maintenance of Offshore Cranes (API RP 2D) to ensure the safety of facility operations. Records of inspection, testing, maintenance, and crane operator qualifications in accordance with the provisions of API RP 2D shall be kept by the lessee at the lessee's field office nearest the Outer Continental Shelf (OCS) facility for a period of 2 years.

(h) *Equipment movement.* The movement of drilling rigs and related equipment on and off an offshore platform or from well to well on the same offshore platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving such rigs and related equipment, unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out.

(i) *Emergency shutdown system.* When drilling operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an Emergency Shutdown System (ESD) manually controlled station shall be installed near the driller's console.

§ 250.52 Welding and burning practices and procedures.

(a) *General requirements.* (1) For the purpose of this rule, the terms "welding" and "burning" are defined to include arc or fuel-gas (acetylene or other gas) cutting and arc or fuel-gas welding.

(2) All offshore welding and burning shall be minimized by onshore fabrication when feasible. The requirements set forth in paragraphs (b), (c), and (d) of this section shall be applicable to any welding or burning practice or procedure performed on the following:

(i) An offshore mobile drilling unit during the drilling mode;

(ii) A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity;

(iii) A platform, structure, artificial island, or other installation during any drilling, well-completion, well-workover, or production operation; and

(iv) A platform, structure, artificial island, or other installation which contains a well open to a hydrocarbon-bearing zone.

(3) All water-discharge-point sources from hydrocarbon-handling vessels shall be monitored in order to stop welding and burning operations in case flammable fluids are discharged as a result of equipment upset or malfunction.

(4) Equipment containing hydrocarbons or other flammable substances shall be relocated at least 35 feet horizontally from the work site. Similar equipment located at a lower elevation where slag, sparks, or other burning materials could fall shall be relocated at least 35 feet from the point

of impact. If relocation is impractical, either the equipment shall be protected with flame-proofed covers or otherwise shielded with metal or fire-resistant guards or curtains, or the contents shall have been rendered inert.

(b) *Welding, burning, and hot tapping plan.* Each lessee shall submit for approval by the District Supervisor a "Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan" prior to beginning the first drilling and/or production operations on a lease. The plan shall include the qualification standards or requirements for personnel who the lessee will authorize to conduct welding, burning, and hot tapping operations and the methods by which the lessee will assure that only trained personnel who meet such standards or requirements are utilized. A copy of this plan and approval letter shall be available on the facility where the welding is conducted. Any person designated as a welding supervisor shall be thoroughly familiar with this plan. An approved plan is required prior to conducting any welding, burning, or hot tapping operation. All welding and burning equipment shall be inspected by the welding supervisor or the lessee's designated person in charge prior to beginning any welding, burning, or hot tapping. All engine-driven welding machines shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition, oxygen and fuel gas bottles shall be secured in a safe place, and leak-free hoses shall be equipped with proper fittings, gauges, and regulators.

(c) *Designated safe-welding and burning areas.* The lessee may establish and designate areas determined to be safe-welding areas. These designated areas shall be identified in the plan, and a drawing showing the location of these areas shall be maintained on the facility.

(d) *Undesignated welding and burning areas.* All welding and burning, which cannot be done in an approved safe-welding area, shall be performed in compliance with the following:

(1) Prior to the commencement of any of these operations, the lessee's designated person in charge at the installation shall inspect the qualifications of the welder(s) to assure that the welder(s) is properly qualified in accordance with the approved qualification standards or requirements for welders. The designated person in charge and the welder(s) shall inspect the work area and area(s) at elevations below the work area where slag, sparks, or other hot materials could fall for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding and burning operation, the designated person-in-charge shall issue a written authorization for the work.

(2) During these welding or burning operations, one or more persons shall be designated as a fire watch. The person(s) assigned as a fire watch shall have no other duties while actual welding or burning operations are in progress. If the operation is to be in an area which is not equipped with a gas detector, the fire watch shall also maintain a continuous surveillance with a portable gas detector during the welding and burning operation. The fire watch shall remain on duty for a period of 30 minutes after welding or burning operations have been completed.

(3) Prior to any of these operations, the fire watch shall have in their possession firefighting equipment in a usable condition.

(4) No welding or burning operation, other than approved hot tapping, shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and are determined to be safe for welding or burning by the designated person in charge.

(5) If drilling, well-completion, well-workover, or wireline operations are in progress, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) in the area where drilling, well-completion, well-workover, or wireline operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded.

(6) If welding or burning operations are conducted in or within 10 feet of a well-bay or production area, all producing wells in the well-bay or production area shall be shut in at the surface safety valve.

§ 250.53 Electrical equipment.

The following requirements shall be applicable to all electrical equipment on all platforms, artificial islands, fixed structures, and their facilities:

(a) All engines with electrical ignition systems shall be equipped with a low-tension ignition system designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture or substance.

(b) All areas shall be classified in accordance with API RP 500B for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms.

(c) All electrical installations shall be made in accordance with API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms, except Sections 7.4, Emergency Lighting and 9.3, Aids to Navigation Equipment.

(d) Maintenance of electrical systems shall be by personnel who are trained and experienced with the area classifications, distribution system, performance characteristics and operation of the equipment, and with the hazards involved.

§ 250.54 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the casing strings in order of normal installation are as follows:

(i) Drive or structural,

(ii) Conductor,

(iii) Surface,

(iv) Intermediate, and

(v) Production casing.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into offshore waters, prevent communication between separate hydrocarbon-bearing strata, protect freshwater aquifers from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids. Cement composition, placement techniques, and waiting time shall be designed and conducted so that the cement in place behind the bottom 500 feet of casing or total length of annular cement fill, if less, attains a minimum compressive strength of 500 pounds per square inch (psi). Cement placed across permafrost zones shall be designed to set before freezing and have a low heat of hydration.

(3) The lessee shall install casing designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof. Safety factors in the casing program design shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well. Any portion of an annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback and which is treated to minimize corrosion.

(4) In cases where cement has filled the annular space back to the mud line,

the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment if the District Supervisor determines that subsurface protection against damage to freshwater aquifers and permafrost zones and against damage caused by adverse loads, pressures, and fluid flows is not jeopardized.

(5) If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall re-cement or take other remedial actions as approved by the District Supervisor.

(6) A pressure-integrity test shall be run below the surface casing, the intermediate casing(s), and liner(s) used as intermediate casing(s). The District Supervisor may require a pressure-integrity test to be run at the conductor casing shoe due to local geologic conditions or planned casing setting depths. Pressure-integrity tests shall be made after drilling new hole below the casing shoe and before drilling more than 50 feet of new hole below a respective casing string. These tests shall be conducted either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as specified in the approved APD. A safe margin, as approved by the District Supervisor, shall be maintained between the mud weight in use and the equivalent mud weight at the casing shoe as determined in the pressure-integrity test. Drilling operations shall be suspended when the safe margin is not maintained. Pressure-integrity and pore-pressure test results and related hole-behavior observations, such as gas-cut mud and well kicks made during the course of drilling, shall be used in adjusting the drilling mud program and the approved setting depth of the next casing string. The results of all tests and of hole-behavior observations made during the course of drilling related to formation integrity and pore pressure shall be recorded in the driller's report.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth as may be prescribed or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, a quantity of cement sufficient to fill the annular space back to the mud line shall be used.

(c) *Conductor and surface casing requirements*—(1) *Conductor and surface casing setting depths.* Conductor and surface casing design and setting depths shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The approved casing setting depths may be adjusted when the change is approved by the District Supervisor to permit the casing shoe to be set in a competent formation or below formations which should be isolated from the wellbore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if the presence of oil or gas is unknown, upon encountering a formation containing oil or gas. Upon encountering unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval. The District Supervisor may permit a lessee to drill a well without setting conductor casing provided the information from approved logging and mud-monitoring programs for wells previously drilled in the immediate vacinity combined with other available geologic data are sufficient to demonstrate the absence of shallow hydrocarbons or hazards.

(2) *Conductor casing cementing requirements.* Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line except as applicable to the bottom of an excavation (glory hole) or to the surface of an artificial island. Cement fill in annular spaces shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) *Surface casing cementing requirements.* (i) Surface casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, surface casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, or as approved or prescribed by the District Supervisor.

(ii) For floating drilling operations, a lesser volume of cement may be used to prevent sealing the annular space between the conductor casing and surface casing if the District Supervisor determines that the uncemented space is necessary to provide protection from burst and collapse pressures which may be applied inadvertently to the annulus between casings during blowout preventer (BOP) testing operations. Any annular space open to the drilled hole shall be sealed in accordance with the requirements for abandonment in Subpart G, Abandonment of Wells, of this part.

(d) *Intermediate casing requirements.* (1) Intermediate casing string(s) shall be set for protection when geologic characteristics or wellbore conditions, as anticipated or as encountered, so indicate.

(2) Quantities of cement that cover and isolate all hydrocarbon-bearing zones in the well and isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 500 feet above the zones to be isolated or 500 feet above the casing shoe in wells where zonal coverage is not required.

(3) If a liner is to be used as an intermediate string below a surface casing string, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for intermediate casing. When a liner is to be used as production casing below a surface casing string, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

(e) *Production casing requirements.* (1) Production casing shall be cemented to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a volume sufficient to fill the annular space at least 500 feet above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.55 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise

approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested again. Additional remedial actions shall be taken until a satisfactory pressure test is obtained. The results of all casing pressure tests shall be recorded in the driller's report.

(b) Each production liner lap shall be tested to a minimum of 500 psi above formation fracture pressure at the shoe of the casing into which the liner is lapped, or as otherwise approved or required by the District Supervisor. The drilling liner-lap test pressure shall be equal to or exceed the pressure that will be encountered at the liner lap when conducting the planned pressure-integrity test below the liner shoe. The test results shall be recorded on the driller's report. If the test indicates an improper seal, remedial action shall be taken which provides a proper seal as demonstrated by a satisfactory pressure test.

(c) In the event of prolonged drill-pipe rotation within a casing string run to the surface or extended operations such as milling, fishing, jarring, washing over, and other operations which could damage the casing, the casing shall be pressure tested or evaluated by a logging technique such as a caliper log every 30 days. The evaluation results shall be submitted to the District Supervisor with a determination of effects of operations on the integrity of the casing for continued service during drilling operations and over the producing life of the well. If the integrity of the casing in the well has deteriorated to an unsafe level, remedial operations shall be conducted or additional casing set in accordance with a plan approved by the District Supervisor prior to continuing drilling operations.

(d) After cementing any string of casing other than the structural casing string, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.56 Blowout preventer systems and system components.

(a) *General.* The BOP systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e)(1), (f), and (g) of this section. The pipe rams shall be of a proper size(s) to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected. The District Supervisor may approve a lower working pressure rating for the annular preventer if the lessee demonstrates that the anticipated or actual well conditions will not place demands above its rated working pressure. (Refer to related requirements in § 250.64(f)(3)(ii) of this part.)

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost.

(2) A backup to the primary accumulator-charging system which shall be automatic, supplied by a power source independent from the power source to the primary accumulator-charging system, and possess sufficient capability to close all BOP components and hold them closed.

(3) At least one operable remote BOP control station in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

(4) A drilling spool with side outlets if side outlets are not provided in the body of the BOP stack to provide for separate kill and choke lines.

(5) For surface BOP systems, a choke and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled except that a check valve may be installed on the kill line in lieu of the remotely controlled valve provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. For subsea BOP systems, a choke and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line and at least one of the valves on the kill line shall be remotely controlled.

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

(7) A choke manifold suitable for the anticipated pressures to which it may be subjected, method of well control to be employed, surrounding environment, and corrosiveness, volume, and abrasiveness of fluids. The choke manifold shall also meet the following requirements:

(i) Manifold and choke equipment subject to well and/or pump pressure shall have a rated working pressure at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor;

(ii) All components of the choke manifold system shall be protected from the danger, if any, of freezing by heating, draining, or filling with proper fluids; and

(iii) When buffer tanks are installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together, isolation valves shall be installed on each line.

(8) Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold with pressure ratings at least as great as the rated working pressure of the ram-type BOP's or as otherwise approved by the District Supervisor.

(9) A wellhead assembly with a rated working pressure that exceeds the anticipated surface pressure to which it may be subjected.

(10) The following system components:

(i) On a conventional drilling rig, a kelly cock installed below the swivel (upper kelly cock), essentially full-opening, and a similar valve of such design that it can be run through the BOP stack (strippable) installed at the bottom of the kelly (lower kelly cock). With a mud motor in service and while using drill pipe in lieu of a kelly, one kelly cock located above and one strippable kelly cock located below the joint of drill pipe employed in lieu of a kelly. On a top-drive system equipped with a remote controlled valve, a second and lower strippable valve of a conventional kelly cock or comparable type either manually or remotely controlled. All required manual and remotely controlled valves of a kelly cock or comparable type in a top-drive system shall be essentially full-opening and tested according to the test pressure and test frequency as stated in

§ 250.57(d) of this part. A wrench to fit each manually operable valve in a conventional drilling rig, mud motor, and top-drive system shall be stored in a location readily accessible to the drilling crew.

(ii) An inside BOP and an essentially full-opening drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew.

(iii) A safety valve available on the rig floor assembled with the proper connection to fit the casing string being run in the hole.

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

(e) *Subsea BOP requirements.* (1) Prior to drilling below surface and intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind-shear rams, and one annular type. A subsea accumulator closing unit or a suitable alternate approved by the District Supervisor is required 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. When proposed casing setting depths or local geology indicate the need for a BOP to provide safety during the drilling of the surface hole, the District Supervisor may require that a subsea BOP system be installed prior to drilling below the conductor casing.

(2) The BOP system shall include operable dual-pod control systems necessary to ensure proper and independent operation of the BOP system functions when drilling below the surface casing.

(3) Prior to the removal of the marine riser, the riser shall be displaced with seawater. Sufficient hydrostatic pressure or other suitable precautions, such as mechanical or cement plugs or closing the BOP, shall be maintained within the wellbore to compensate for the reduction in pressure and to maintain a safe controlled well condition.

(4) Any necessary repair or replacement of the BOP system or a system component after installation shall be accomplished under safe controlled conditions, (e.g., after casing has been cemented but prior to drilling out the casing shoe or by setting a cement plug, bridge plug, or a packer).

(5) When a subsea BOP system is to be used in an area which is subject to ice scour, the BOP stack shall be placed in an excavation (glory hole) of sufficient depth to assure that the top of the stack is below the deepest probable ice-scour depth.

(f) *Surface BOP requirements.* Prior to drilling below surface or intermediate casing, a BOP system shall be installed consisting of at least four remote controlled, hydraulically operated BOP's including at least two equipped with pipe rams, one with blind rams, and one annular type.

(g) *Tapered drill-string operations.* (1) Prior to commencing tapered drill-pipe operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams installed in two or more ram cavities to provide the following:

(i) Two sets of pipe rams capable of sealing around the larger size drill string, and

(ii) One set of pipe rams capable of sealing around the smaller size drill string.

(2) Subsea BOP systems shall have blind-shear ram capability. Surface BOP systems shall have blind ram capability.

§ 250.57 Blowout preventer systems tests, actuations, inspections, and maintenance.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a low pressure of 200 to 300 psi.

(b) Surface ram-type BOP's and the choke manifold shall be pressure tested with water to rated working pressure or as otherwise approved by the District Supervisor. The annular-type BOP shall be pressure tested with water to 70 percent of its rated working pressure or as otherwise approved by the District Supervisor.

(c) Subsea BOP system components shall be stump pressure tested at the surface with water to their rated working pressure, except that the annular-type BOP shall not be pressure tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the seafloor, the ram-type BOP's and choke manifold shall be pressure tested to rated working pressure or as otherwise approved by the District Supervisor. The annular preventer shall be pressure tested to 70 percent of its rated working pressure or as otherwise approved by the District Supervisor.

(d) In conjunction with the weekly pressure test of surface and subsea BOP systems required in paragraph (e) of this section, the choke manifold valves; upper and lower kelly cocks; top-drive, inside-BOP, and the drill-string safety valves shall be pressure tested to pipe-ram test pressures or otherwise approved by the District Supervisor. Safety valves assembled with proper casing connections shall be actuated prior to running casing.

(e) Surface and subsea BOP systems shall be pressure tested as follows:

(1) When installed.

(2) Before drilling out each string of casing or before continuing operations in cases where the cement is not drilled out.

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations and pods. If either control station or pod is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is stuck drill pipe or pressure-control operations and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams.

(4) Blind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than that necessary to indicate proper operation of the rams is not required.

(5) Variable bore-pipe rams shall be pressure-tested against all sizes of pipe in use, excluding drill collars and bottom-hole tools.

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly but limited to the affected component.

(f) All BOP systems and marine risers shall be inspected and maintained to assure that the equipment will function properly. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of BOP systems and marine risers may be accomplished by the use of television equipment. The District Supervisor may approve alternate methods of inspection of marine risers on dynamic-positioned rigs. Casing risers on fixed structures and jackup rigs are not subject to the daily underwater inspection requirement.

(g) The results of all pressure tests, actuations, and inspections of the BOP system, system components, and marine risers shall be recorded in the driller's report.

§ 250.58 Well-control drills.

(a) Well-control drills shall be conducted for each drilling crew in accordance with the following requirements:

(1) Drills shall be designed to acquaint each crew member with each member's function at the particular test station so each member can perform their functions promptly and efficiently.

(2) A well-control drill plan, applicable to the particular site, shall be prepared for each crew member outlining the assignments each member is to fulfill during the drill and establishing a prescribed time for the completion of each portion of the drill. A copy of the complete well-control drill plan shall be posted on the rig floor and/or bulletin board.

(3) The drill shall be carried out during periods of activity selected to minimize the risk of sticking the drill pipe or otherwise endangering the operation. In each of these drills, the reaction time of participants shall be measured up to the point when the designated person is prepared to activate the closing sequence of the BOP system. The total time for the crew to complete its entire drill assignment shall also be measured. This operation shall be recorded on the driller's report as "Well-Control Drill." All drills shall be initiated by the toolpusher through the raising of the float on the pit-level device, activating the mud-return indicator, or its equivalent. This operation shall be performed at least once each week (well conditions permitting) with each crew. The drills shall be timed so they will cover a range of different operations which include on-bottom drilling and tripping. A diverter drill shall be developed and conducted in a similar manner for shallow operations.

(4) *On-bottom drilling.* A drill conducted while on bottom shall include the following as practicable:

(i) Detect kick and sound alarm;

(ii) Position kelly and tool joints so connections are accessible from floor, but tool joints are clear of sealing elements in BOP systems, stop pumps, check for flow, close in the well;

(iii) Record time;

(iv) Record drill-pipe pressure and casing pressure;

(v) Measure pit gain and mark new level;

(vi) Estimate volume of additional mud in pits;

(vii) Weight sample of mud from suction pit;

(viii) Check all valves on choke manifold and BOP system for correct position (open or closed);

(ix) Check BOP system components and choke manifold for leaks;

(x) Check flow line and choke exhaust lines for flow;

(xi) Check accumulator pressure;

(xii) Prepare to extinguish sources of ignition;

(xiii) Alert standby boat or prepare safety capsule for launching;

(xiv) Place crane operator on duty for possible personnel evacuation;

(xv) Prepare to lower escape ladders and prepare other abandonment devices for possible use;

(xvi) Determine materials needed to circulate out kick; and

(xvii) Time drill and enter drill report on driller's report.

(5) *Tripping pipe.* A drill conducted during a trip shall include the following as practicable:

(i) Detect kick and sound alarm;

(ii) Install safety valve, close safety valve;

(iii) Position pipe, prepare to close annular preventer;

(iv) Install inside preventer, open safety valve;

(v) Record time;

(vi) Record casing pressure;

(vii) Check all valves on choke manifold and BOP system for correct position (open or closed);

(viii) Check for leaks on BOP system component and choke manifold;

(ix) Check flow line and choke exhaust lines for flow;

(x) Check accumulator pressure;

(xi) Prepare to extinguish sources of ignition;

(xii) Alert standby boat or prepare safety capsule for launching;

(xiii) Place crane operator on duty for possible personnel evacuation;

(xiv) Prepare to lower escape ladders and prepare other abandonment devices for possible use;

(xv) Prepare to strip back to bottom; and

(xvi) Time drill and enter drill report on driller's report.

(b) A well-control drill may be required by a Minerals Management Service (MMS) authorized representative after consulting with the lessee's senior representative present.

§ 250.59 Diverter systems.

(a) When drilling a conductor or surface hole, all drilling units shall be equipped with a diverter system consisting of a diverter sealing element, diverter lines, and control systems unless otherwise approved by the District Supervisor for floating drilling operations. The diverter system shall be designed, installed, and maintained so as to divert gases, water, mud, and other materials away from the facilities and personnel.

(b) No later than May 31, 1990, diverter systems shall be in compliance with the requirements of this section. The requirements applicable to diverters which were in effect April 1, 1988 shall remain in effect until May 31, 1990.

(c) The diverter system shall be equipped with remote-controlled valves in the flow and vent lines that can be operated from at least one remote-control station in addition to the one on the drilling floor. Any valve used in a diverter system shall be full-opening. No manual or butterfly valve shall be installed in any part of the diverter system. There shall be a minimum number of turns in the vent line(s) downstream of the spool outlet flange and the radius of curvature of turns shall be as large as practicable. All right-angle and sharp turns shall be targeted. Flexible hose may be used for diverter lines instead of rigid pipe if the flexible hose has integral end couplings. The entire diverter system shall be firmly anchored and supported to prevent whipping and vibration. All diverter control instruments and lines shall be protected from physical damage from thrown and falling objects.

(d) For drilling operations conducted with a surface wellhead configuration, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability; and

(2) No spool outlet or diverter line internal diameter shall be less than 10 inches, except that dual spool outlets are acceptable provided that each outlet has a minimum internal diameter of 8 inches and that both outlets are piped to overboard lines and that each line downstream of the changeover nipple at the spool has a minimum internal diameter of 10 inches.

(e) For drilling operations conducted where a floating or semisubmersible type of drilling vessel is used and drilling fluids are circulated to the drilling vessel, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability;

(2) No spool outlet or diverter line internal diameter shall be less than 12 inches; and

(3) Dynamically positioned drill ships may be equipped with a single vent line provided appropriate vessel heading is maintained to allow for downwind diversion.

(f) The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nippled up on conductor casing with a surface

wellhead configuration. No more than 7 days shall elapse between subsequent similar pressure tests. For surface and subsea wellhead configurations, the diverter sealing element, diverter valves, and diverter-control systems, including the remote control system, shall be actuation-tested and the vent lines flow tested when first installed. Subsequent actuation tests shall be conducted not less than once every 24-hour period thereafter alternating between control stations. All pressure test, flow test, and actuation results shall be recorded in the driller's report.

(g) Diverter systems and components for use in subfreezing conditions shall be suitable for use under these conditions.

§ 250.60 Mud program.

(a) *General requirements.* The quantities, characteristics, use, and testing of drilling mud and the related drilling procedures shall be designed and implemented to prevent the loss of well control.

(b) *Mud control.* (1) Before starting out of the hole with drill pipe, the mud shall be properly conditioned by circulation with the drill pipe just off bottom to the extent that a volume of drilling mud equal to the annular volume is displaced. This procedure may be omitted if proper documentation in the driller's report shows the following:

(i) There is no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

(ii) The weight of the returning mud is essentially the same as the weight of the mud entering the hole. In the event that the returning mud is lighter than the entering mud by a weight differential equal to or greater than 0.2 pounds per gallon (1.5 pounds per cubic foot), the mud shall be circulated until a volume of drilling mud equal to the annular volume is displaced, and the mud properties measured to assure that there has been no influx of gas or liquid.

(iii) Other mud properties recorded on the daily drilling log are within the limits established by the approved mud program.

(2) When mud in the hole is circulated, the driller's report shall be so noted.

(3) When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure by 75 psi, or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted near the driller's station. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

(4) Drill pipe and downhole tool running and pulling speeds shall be at controlled rates so as not to induce an influx of formation fluids from the effects of swabbing nor cause a loss of drilling fluid and corresponding hydrostatic pressure decrease from the effects of surging.

(5) When there is an indication of swabbing or influx of formation fluids, the safety devices and measures necessary to control the well shall be employed. The mud shall be circulated and conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

(6) For each casing string, the maximum pressure to be contained under the BOP shall be posted near the driller's station.

(7) In areas where permafrost and/or hydrate zones may be present or are known to be present, drilling fluid temperatures shall be controlled or other measures taken to drill safely through those zones.

(8) An operable mud-gas separator and operable degasser shall be installed in the mud system prior to commencement of drilling operations and shall be maintained for use throughout the drilling of the well.

(9) The mud in the hole shall be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole. If circulating out test fluid is not feasible, test fluids may be bullheaded out of the drill-stem test string and tools with an appropriate kill fluid prior to pulling the test tools.

(c) *Mud-testing and monitoring equipment.* (1) Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with industry-accepted practices and shall include mud density, viscosity, and gel strength, hydrogen-ion concentration (pH), filtration, and other tests as may be deemed necessary by the District Supervisor in the interests of monitoring and maintaining mud quality for safe operations, prevention of downhole equipment problems, and for kick detection. The results of these tests shall be recorded in the driller's report.

(2) The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

(i) Recording mud-pit level indicator to determine mud-pit volume gains and losses. This indicator shall include both a visual and an audible warning device.

(ii) Mud-volume measuring device to accurately determine mud volumes required to fill the hole on trips.

(iii) Mud-return indicator devices which indicate the relationship between mud-return flow rate and pump discharge rate. This indicator shall include both a visual and an audible warning device.

(iv) Gas-detecting equipment to monitor the drilling mud returns with indicators located in the mud-logging compartment or on the rig floor. If the indicators are only in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the gas-detecting equipment shall be continually manned. If the indicators are on the rig floor only, an audible alarm shall be installed.

(d) *Mud quantities.* (1) Quantities of mud and mud materials at the drill site shall be utilized, maintained, and replenished as necessary to ensure well control. Those quantities shall be based on known or anticipated drilling conditions to be encountered, rig storage capacity, weather conditions, and estimated time for delivery.

(2) Daily inventories of mud and mud materials including weight materials and additives at the drill site shall be recorded and those records maintained at the well site.

(3) Drilling operations shall be suspended in the absence of sufficient quantities of mud and mud materials to maintain well control.

(e) *Safety precautions in enclosed mud-handling areas.* Mud-handling areas which are classified as per API RP 500B where dangerous concentrations of combustible gas may accumulate shall be equipped with ventilation systems and gas monitors as described below no later than May 31, 1989. Regulatory requirements in effect on April 1, 1988 are applicable until May 31, 1989.

(1) Be ventilated with high-capacity mechanical ventilation systems 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, unless such ventilation is provided by natural means. If not continuously activated, mechanical ventilation systems shall be activated on signal from gas detectors that are operational at all times indicating the presence of 1 percent or more of gas by volume.

(2) Be maintained at a negative pressure relative to an adjacent area if mechanical ventilation is installed to

meet the requirements in paragraph (e)(1) of this section and discharges may be hazardous. The negative pressure areas shall be protected with at least one of the following: (i) A pressure-sensitive alarm, (ii) open-door alarms on each access to the area, (iii) automatic door-closing devices, (iv) air locks, or (v) other devices as approved by the District Supervisor.

(3) Be fitted with gas detectors and alarms except in open areas where adequate ventilation is provided by natural means.

(4) Be equipped with either explosion-proof or pressurized electrical equipment to prevent the ignition of explosive gases. Where air is used for pressuring, the air intake shall be located outside of, and as far as practicable from, hazardous areas.

(5) Mechanical ventilation systems shall be fitted with alarms which are activated upon a failure of the system.

(6) Gas detection systems shall be tested for operation and recalibrated at a frequency such that no more than 90 days shall elapse between tests.

§ 250.61 Securing of wells.

A downhole safety device such as a cement plug, bridge plug, or packer shall be timely installed when drilling operations are interrupted by events such as those which force evacuation of the drilling crew, prevent station keeping, or require repairs to major drilling or well-control equipment. In floating drilling operations, the use of blind-shear rams or pipe rams and an inside BOP may be approved by the District Supervisor in lieu of the above requirements if supported by evidence of special circumstances and/or the lack of sufficient time.

§ 250.62 Field drilling rules.

When geological and engineering information available in a field enables a District Supervisor to determine specific operating requirements appropriate to wells to be drilled in the field, field drilling rules may be established on the initiative of the District Supervisor, or in response to a request from a lessee. Such rules may modify the requirements of this subpart. After field drilling rules have been established, development wells to which such rules apply shall be drilled in accordance with such rules and other requirements of this subpart. Field drilling rules may be amended or cancelled for cause at any time upon the initiative of the District Supervisor or upon the approval of a request by a lessee.

§ 250.63 Supervision, surveillance, and training.

(a) The lessee shall provide onsite supervision of drilling operations on a 24-hour per day basis.

(b) From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with BOP's, bridge plugs, packers, or cement plugs.

(c) Lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of Subpart O of this part and MMS Training Standard MMS–OCS–T 1, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling Offshore Locations (Second Edition). Records of specific training which lessee and drilling contractor personnel have successfully completed, the dates of completion, and the names and dates of the courses shall be maintained at the drill site.

§ 250.64 Applications for Permit to Drill.

(a) Prior to the initial drilling of a well under an approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, the lessee shall file a Form MMS–331C, APD, with the District Supervisor for approval. Prior to commencing operations, written approval from the District Supervisor must be received by the lessee unless oral approval is given.

(b) The APD's for wells to be drilled from mobile drilling units shall include the following:

(1) An identification of the maximum environmental and operational conditions the rig is designed to withstand.

(2) Applicable current documentation of operational limitations imposed by the American Bureau of Shipping classification or other appropriate classification society and either a U.S. Coast Guard Certificate of Inspection or a U.S. Coast Guard Letter of Compliance.

(3) For frontier areas, the design and operating limitations beyond which suspension, curtailment, or modification of drilling or rig operations are required (e.g., vessel motion, offset, riser angle, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability) and the contingency plans which identify actions to be taken prior to exceeding the design or operating limitations of the rig.

(4) A program which provides for safety in drilling operations where a floating or semisubmersible type of drilling vessel is used and formation competency at the structural and/or conductor casing setting depth(s) is (are) not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor and/or surface hole. This program shall include all known pertinent information including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor and/or surface casing seat(s), and the contingency plan for moving off location.

(c) The APD's shall include rated capacities of the proposed drilling unit and of major drilling equipment.

(d) In those areas which are subject to subfreezing conditions, the lessee shall furnish evidence that the drilling equipment, BOP system and components, drilling safety systems, diverter systems, and other associated equipment and materials are suitable for drilling operations under subfreezing conditions.

(e) After a drilling unit has been approved for use in an MMS District, the information listed in paragraphs (b)(1), (2), and (3), (c), and (d) of this section need not be resubmitted unless required by the District Supervisor or there are changes in equipment that affect the rated capacity of the unit.

(f) An APD shall include the following in addition to a fully completed Form MMS–331C:

(1) A plat, drawn to a scale of 2,000 feet to the inch, showing the surface and subsurface location of the well to be drilled and of all the wells previously drilled in the vicinity from which information is available. Locations shall be indicated in feet from the block line.

(2) The design criteria considered for the well and for well control, including the following:

(i) Pore pressures.

(ii) Formation fracture gradients.

(iii) Potential lost circulation zones.

(iv) Mud weights.

(v) Casing setting depths.

(vi) Anticipated surface pressures (which for purposes of this section are defined as the pressure which can reasonably be expected to be exerted upon a casing string and its related wellhead equipment). In the calculation of an anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. The lessee shall consider mud densities to be used below various casing strings, fracture gradients of the

exposed formations, casing setting depths, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressures the calculations used to determine these pressures during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design.

(vii) If a shallow hazards site survey is conducted, the lessee shall submit with or prior to the submittal of the APD, two copies of a summary report describing the geological and manmade conditions present. The lessee shall also submit two copies of the site maps and data records identified in the survey strategy.

(viii) Permafrost zones, if applicable.

(3) A BOP equipment program including the following:

(i) The pressure rating of BOP equipment.

(ii) A well-control procedure for use of the annular preventer for those wells where the anticipated surface pressure exceeds the rated working pressure of the annular preventer.

(iii) A description of subsea BOP accumulator system or other type of closing system proposed for use.

(iv) A schematic drawing of the diverter system to be used (plan and elevation views) showing spool outlet internal diameter(s); diverter-line lengths and diameters, burst strengths, and radius of curvature at each turn; valve type, size, working pressure rating, and location; the control instrumentation logic; and the operating procedure to be used by lessee or contractor personnel.

(v) A schematic drawing of the BOP stack showing the inside diameter of the BOP stack, and the number of annular, pipe ram, variable-bore pipe ram, blind ram, and blind-shear ram preventers.

(4) A casing program including the following:

(i) Casing size, weight, grade, type of connection, and setting depth;

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

(iii) In areas containing permafrost, casing programs that incorporate setting depths for conductor and surface casing based on the anticipated depth of the permafrost at the proposed well location and which utilize the current state-of-the-art methods to safely drill and set casing. The casing program shall provide protection from thaw subsidence and freezeback effect, proper anchorage, and well control.

(5) The drilling prognosis including the following:

(i) Projected plans for coring at specified depths;

(ii) Projected plans for logging;

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

(iv) Estimated depths at which encounters with significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured water are expected.

(6) A cementing program including type and amount of cement in cubic feet to be used for each casing string.

(7) A mud program including the minimum quantities of mud and mud materials, including weight materials, to be kept at the site.

(8) A directional survey program for directionally drilled wells.

(9) A plot of the estimated pore pressures and formation fracture gradients and the proposed mud weights and casing setting depths on the same sheet.

(10) A H_2S Contingency Plan, if applicable, and not submitted previously.

(11) Such other information as may be required by the District Supervisor.

(g) Public information copies of the APD shall be submitted in accordance with § 250.17 of this part.

§ 250.65 Sundry notices and reports on wells.

(a) Notices of the lessee's intention to change plans, make changes in major drilling equipment, deepen or plug back a well, or engage in similar activities and subsequent reports pertaining to such operations shall be submitted to the District Supervisor on Form MMS–331, Sundry Notices and Reports on Wells. Prior to commencing operations, written approval must be received from the District Supervisor unless oral approval is obtained.

(b) The Form MMS–331 submitted shall contain a detailed statement of the proposed work that will materially change from the approved work described in the APD. Information submitted shall include the present status of the well, including the production string or last string of casing, the well depth, the present production zones and productive capability, and all other information specified on Form MMS–331. Within 30 days after completion of the work, a subsequent detailed report of all the work done and the results obtained shall be submitted.

(c) A Form MMS–331 with a plat, certified by a registered land surveyor, shall be filed as soon as the well's final surveyed surface location, water depth, and the rotary kelly bushing elevation have been determined.

(d) Public information copies of Sundry Notices and Reports on Wells shall be submitted in accordance with § 250.17 of this part.

§ 250.66 Well records.

(a) Complete and accurate records for each well and of all well operations shall be retained for a period of 2 years at the lessee's field office nearest the OCS facility or at another location conveniently available to the District Supervisor. The records shall contain a description of any significant malfunction or problem; all the formations penetrated; the content and character of oil, gas, and other mineral deposits and water in each formation; the kind, weight, size, grade, and setting depth of casing; all well logs and surveys run in the wellbore; and all other information required by the District Supervisor in the interests of resource evaluation, waste prevention, conservation of natural resources, protection of correlative rights, safety, and environment.

(b) When drilling operations are suspended, or temporarily prohibited under the provisions of § 250.10 of this part, the lessee shall, within 30 days after termination of the suspension or temporary prohibition or within 30 days after the completion of any activities related to the suspension or prohibition, transmit to the District Supervisor duplicate copies of the records of all activities related to and conducted during the suspension or temporary prohibition on, or attached to, Form MMS–330, Well (Re)Completion Report, or Form MMS–331, as appropriate.

(c) Upon request by the Regional or District Supervisor, the lessee shall furnish the following:

(1) Copies of the records of any of the well operations specified in paragraph (a) of this section;

(2) Paleontological reports identifying microscopic fossils by depth and/or washed samples of drill cuttings normally maintained by the lessee for paleontological determinations;

(3) Copies of the daily driller's report at a frequency as determined by the District Supervisor. Items to be reported include spud dates, casing setting depths, cement quantities, casing characteristics, pressure integrity tests, mud weights, kicks, lost returns, and any unusual activities; and

(4) Legible, exact copies of service company reports on cementing, perforating, acidizing, analyses of cores, testing, or other similar services.

(d) As soon as available, the lessee shall transmit copies (field or final prints of individual runs) of logs or charts of electrical, radioactive, sonic, and other well-logging operations, directional-well surveys, and analyses of cores. Composite logs of multiple runs and directional-well surveys shall be transmitted to the District Supervisor in duplicate as soon as available but not later than 30 days after completion of each well.

(e) If the drilling unit moves from the wellbore prior to completing the well, the lessee shall submit to the District Supervisor copies of the well records with completed Form MMS–331, within 30 days after moving from the wellbore.

(f) If the Regional or District Supervisor determines that circumstances warrant, the lessee shall submit any other reports and records of operations, including paleontological interpretations based upon identification of microscopic fossils, in the manner and form prescribed by the Regional or District Supervisor.

(g) Records relating to the drilling of a well shall be retained for a period of 90 days after drilling operations are completed. Records relating to the completion of a well or of any workover activity which materially alters the completion configuration or materially affects or alters a hydrocarbon-bearing zone shall be kept until the well is permanently plugged and abandoned.

§ 250.67 Hydrogen sulfide.

(a) *General requirements and applicability.* (1) The lessee shall take all necessary and practicable precautions and measures to protect personnel from the toxic effects of H_2S and to mitigate the adverse effects of H_2S to property and the environment.

(2) The requirements of this section apply, as appropriate, to drilling, well-completion, well-workover (including well-servicing), and production operations in zones known to contain H_2S and to drilling, well-completion, and well-workover operations in zones where the presence of H_2S is unknown. The requirements are not applicable to operations in zones where the absence of H_2S has been confirmed.

(b) *Definitions.* As used in this section, terms shall have the meanings given below:

"Facility" means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

"Well-control fluid" means drilling mud, completion fluid, or workover fluid as appropriate to the particular operation being conducted.

"Zones known to contain H_2S" means geologic formations where prior drilling operations or logging, coring, testing, or producing operations have confirmed that H_2S-bearing zones will be encountered that could potentially result in atmospheric concentrations of 20 parts per million (ppm) or more of H_2S.

"Zones where the absence of H_2S has been confirmed" means one of the following:

(1) Geologic formations where prior drilling operations or logging, coring, testing, or producing operations have indicated that H_2S-bearing zones have not been encountered that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S;

(2) Geologic formations where analysis of produced gas samples have indicated the absence of H_2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S; or

(3) An area in a geological province in which there has been no prior drilling but from prior drilling in the surrounding areas, it can be shown by correlation of geological and seismic data that equivalent stratigraphic units exist with an absence of H_2S throughout the area to be drilled.

"Zones where the presence of H_2S is unknown" means geologic formations where neither the presence nor absence of H_2S has been confirmed.

(c) *Request for classification of probability of encountering H_2S during operations.* Prior to beginning operations in an area, the lessee shall submit to the Regional Supervisor for approval a request for determination as to whether the proposed operations will be in areas classified as "Zones known to contain H_2S," "Zones where the presence of H_2S is unknown," or "Zones where the absence of H_2S has been confirmed." The classification request shall be supported by a recommendation drawn from available information such as geologic and geophysical data and correlations, well logs, formation tests, cores, and analyses of formation fluids. The classification shall be updated when additional data indicate there is cause for a change in an approved classification.

(d) *Drilling, well-completion, and well-workover operations in zones known to contain H_2S.* Drilling, well-completion, and well-workover operations in zones known to contain H_2S shall be conducted in accordance with the requirements of this paragraph (d) and of paragraphs (h), (i), (j), (k), (l) (1) through (5), and (m) (1) through (13) of this section.

(e) *Drilling and well-completion operations in zones where the presence of H_2S is unknown.* When drilling or completing in zones where the presence of H_2S is unknown, only the requirements of paragraph (h) of this section shall apply. In the event that H_2S is encountered that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S, the requirements of paragraph (d) of this section shall apply.

(f) *Production operations in zones known to contain H_2S.* Production operations in zones known to contain H_2S shall comply with the requirements in paragraphs (h), (l) (1) through (6), and (m) (7) through (16) of this section.

(g) *Simultaneous operations.* Any combination of drilling, well-completion, well-workover, and production operations conducted simultaneously shall comply with all the requirements in this section applicable to each individual operation and in conformance with the coordinated H_2S Contingency Plan as required in paragraph (h)(1) of this section.

(h) *Personnel safety and protection.* The following measures shall be implemented for personnel safety and protection.

(1) *H_2S Contingency Plan.* An H_2S Contingency Plan shall be submitted for approval to the District Supervisor prior to the commencement of operations and, as applicable, encompass simultaneous drilling, well-completion, well-workover, and production operations. A copy of the approved plan shall be made available in the field area until operations are completed. The H_2S Contingency Plan shall include the following:

(i) Safety procedures and equipment, training, drills, and smoking rules.

(ii) Identity of the job position, title of the person responsible for the overall safety of personnel, and a description of the organization and assignments of functions, duties, and responsibilities of other identified job positions.

(iii) Duties, responsibilities, and operating procedures to be initiated when the concentration of H_2S in the atmosphere reaches the following:

(A) 10 ppm level,

(B) 20 ppm level, and

(C) 50 ppm level.

(iv) Designation of briefing areas as locations for assembly of personnel during conditions of 20-ppm and 50-ppm concentrations of H_2S. At least two briefing areas shall be established on each facility. The briefing area that is upwind of the H_2S source at any given time shall be the designated briefing area.

(v) Procedures for the evacuation of personnel which shall be comprehensive and provide for the deboarding and safe evacuation of all personnel from the facility. The procedures shall address the positioning of all vessels attendant to the facility, their reactions to an emergency, and the provisions for protective-breathing equipment for personnel.

(vi) Agencies to be notified in case of an emergency.

(vii) A list of medical personnel and facilities including addresses and telephone numbers.

(2) *Training Program.* An onsite H_2S-safety training program shall be established that includes the following:

(i) All personnel whether regularly assigned, contracted for, or employed on an unscheduled basis shall be informed of the hazards of H_2S and of SO_2 resulting from burning H_2S and instructed in the provisions for personnel safety contained in the H_2S Contingency Plan.

(ii) All personnel shall be instructed in the proper use of safety equipment which they may be required to use.

(iii) All personnel shall be informed of the location of protective-breathing equipment, H_2S detectors and alarms, ventilation equipment, briefing areas, warning systems, evacuation procedures, and the direction of the prevailing winds.

(iv) All personnel shall be informed of the restrictions and corrective measures concerning beards, spectacles, and contact lenses in conformance with American National Standard Institute (ANSI), Practices for Respiratory Protection (ANSI Z88.2).

(v) Safety information shall be prominently posted on the facility and on vessels serving the facility.

(vi) A drill shall be conducted for each person at the facility within 24 hours after duty begins and at least once during every subsequent 7-day period. A training session shall be conducted for each person upon arrival at the facility and at least once during every subsequent 7-day period. Records of attendance for drilling, well-completion, and workover operations shall be kept at the facility until operations are completed. Records of attendance for production operations shall be maintained at the facility or at the nearest field office for a period of 1 year. Drills and training may be conducted in conjunction with other safety meetings or with rig/facility abandonment drills.

(vii) Personnel shall be instructed in basic first-aid procedures applicable to victims of H_2S exposure. During all drills and training sessions, procedures for rescue and first aid for H_2S victims shall be addressed. Each facility shall have the following equipment readily available, and personnel shall be instructed as to the location and use of the following items:

(A) A first-aid kit of appropriate size and content for the number of personnel on the facility;

(B) Resuscitators complete with face masks, oxygen bottles, and spare oxygen bottles; and

(C) At least one litter or an equivalent device.

(viii) Personnel shall be informed of the meaning of all warning signals.

(3) *Visual warning system.* Visual warning systems shall comply with the following:

(i) Wind-direction equipment shall be installed at prominent locations to indicate to all personnel, on or in the immediate vicinity of the facility, the wind direction at all times to determine safe upwind areas in the event that H_2S or SO_2 is present in the vicinity; and

(ii) Operational danger signs shall be displayed from each side of the facility and a sufficient number of rectangular red flags shall be hoisted in a manner visible to vessels and aircraft and shall comply with the following:

(A) Each sign shall be of a minimum width of 8 feet and a minimum height of 4 feet and shall be a high-visibility yellow color with black lettering of a minimum of 12 inches in height reading as follows:

DANGER—HYDROGEN SULFIDE—H_2S

(B) Each red flag shall be of a minimum width of 3 feet and a minimum height of 2 feet.

(C) All signs and flags shall be illuminated at night and under conditions of poor visibility.

(D) Only signs shall be displayed when cases where the concentration in the atmosphere reaches 20 ppm. Visual alarms shall be activated when atmospheric concentration reaches 20 ppm. Signs and flags shall be displayed when the concentration in the atmosphere reaches 50 ppm.

(E) On facilities with wells capable of producing H_2S, warning signs differentiated from those required under paragraph (A) above shall be permanently installed at the heliport and at boat landings.

(4) *Audible warning system.* A public address system and a siren, horn, or other similar warning device with a unique sound used only for H_2S warnings shall be installed at appropriate locations on the facility. The warning devices (audible and visual) shall be suitable for the electrical classification of the area and shall be activated by the H_2S-detection and H_2S-monitoring equipment when the atmospheric concentration reaches 20 ppm. When the warning devices are activated, the designated responsible persons shall inform personnel of the level of danger and issue instructions on the initiation of appropriate protective measures.

(5) *H_2S-detection and H_2S-monitoring equipment.* (i) Each facility shall have an H_2S-detection and H_2S-monitoring system which activates audible and visual alarms when the atmospheric concentration reaches 20 ppm. The detection systems shall be capable of sensing a minimum 10 ppm of H_2S in the atmosphere with sensing points located at the bell nipple, shale shaker, well-control fluid pit area, driller's station, living quarters, and all areas as appropriate including those which are low, poorly ventilated, or confined where H_2S may accumulate.

(ii) The H_2S-detection and H_2S-monitoring equipment shall be calibrated at least once every 24 hours when drilling approaches a potential H_2S-bearing zone and at least once every 12 hours when drilling, well-completion, and/or well-workover operations are being conducted in an H_2S environment. The H_2S detectors for production operations shall be calibrated at a frequency such that no more than 7 days shall elapse between calibrations. The calibration shall be conducted by a person trained to calibrate the particular H_2S-detection and H_2S-monitoring equipment being used. All calibrations shall be recorded in the driller's or production operations report as applicable.

(iii) H_2S-detection ampoules or any other comparable H_2S-monitoring devices capable of detecting 20 ppm shall be available for use by all personnel. After H_2S has been initially detected, poorly ventilated areas which are not equipped with fixed H_2S monitoring/detection equipment shall be promptly surveyed and evaluated with appropriate frequency using a portable H_2S-detection instrument.

(6) *Protective-breathing equipment.* Protective-breathing equipment and its use shall conform to the following:

(i) Personnel on a facility operating in known or unknown H_2S zones shall have immediate access to pressure-demand-type respirators. The design, selection, use, and maintenance of these respirators shall conform to ANSI Z88.2, Practices for Respiratory Protection. Accessory equipment such as voice-transmission devices and spectacle kits shall be made available as needed.

(ii) The storage location of protective-breathing equipment shall be quickly and easily accessible to all personnel.

(iii) All breathing-air bottles shall be labeled as containing breathing-quality air for human use.

(iv) Vessels attendant to facilities operating in known or unknown H_2S zones shall carry appropriate protective-breathing equipment for each crew member. The District Supervisor may require additional protective-breathing equipment on certain vessels attendant to the facility.

(v) Helicopters attendant to facilities operating in known H_2S zones shall carry pressure-demand-type respirators for the flight crews. Facilities operating in unknown H_2S zones shall store pressure-demand-type respirators immediately accessible to the heliport for the use of flight crews. All members of flight crews shall be trained in the use of the particular type(s) of respirator equipment made available.

(vi) As appropriate to the particular operation(s) (drilling, well-completion, or well-workover operation or any combination thereof), a system of breathing-air manifolds, hoses, and masks shall be provided on the facility and in the briefing areas. A cascade air-bottle system shall be provided for the breathing-air manifolds and to refill individual protective-breathing apparatus bottles. The cascade air-bottle system may be recharged by a high-pressure compressor suitable for providing breathing-quality air provided the compressor suction is located in an uncontaminated atmosphere.

(7) *Additional personnel-safety equipment.* The following additional personnel-safety equipment shall be available:

(i) Portable H_2S detectors;

(ii) Retrieval ropes with safety harnesses to retrieve incapacitated personnel from contaminated areas;

(iii) Chalkboards and/or note pads for communication purposes located on the rig floor, shale-shaker area, the cement-pump rooms, well-bay areas, production processing equipment area, gas compressor area, and pipeline-pump area;

(iv) Bull horns and flashing lights; and

(v) Resuscitators.

(8) *Ventilation equipment.* All ventilation devices shall be explosion-proof and situated in areas where H_2S or SO_2 may accumulate. Movable ventilation devices shall be provided in work areas and be multidirectional and capable of dispersing H_2S or SO_2 vapors away from working personnel.

(9) *Notification of regulatory Agencies.* The MMS and U.S. Coast Guard shall be notified as soon as possible in the event of a non routine release of H_2S which results in an atmospheric concentration of 20 ppm and 50 ppm levels.

(i) *Drilling, completion, and workover fluids program when operating in zones known to contain H_2S.*—(1) *Well-control fluid base.* Either water- or oil-base muds may be used in drilling formations containing H_2S.

(2) *Well-control fluid testing.* If water-base, well-control fluids are used, and if H_2S is detected by air sensors, either the Garrett-Gas-Train test or comparable test techniques for soluble sulfides shall be conducted immediately to confirm the presence of H_2S. If the concentration detected by air sensors is in excess of 20 ppm, personnel conducting the tests shall don protective-breathing equipment conforming to paragraph (h)(6)(i) of this section.

(3) *Additives.* Sufficient quantities of additives for the control of H_2S, well-control fluid pH, and corrosion of equipment shall be maintained on the facility.

(i) *Scavengers.* Prior to drilling into a known H_2S-bearing zone, scavengers for control of H_2S shall be available on the facility. When H_2S is detected, scavengers shall be added as needed. Drilling shall be suspended until the scavenger is circulated throughout the system.

(ii) *Control of pH.* Additives for the control of pH shall be added to water-base well-control fluids in sufficient quantities to maintain a pH of at least 10.0.

(iii) *Corrosion inhibitors.* Additives for the control of corrosion shall be added to the well-control fluid system as needed.

(4) *Degassing.* Well-control fluids containing H_2S shall be degassed at the optimum location for the particular facility. The gases so removed shall be collected and burned in a closed flare system conforming to paragraph (m)(7) of this section.

(j) *Kick detection and well control.* In the event of a kick, the disposal of the well-influx fluids shall be accomplished by one of the following alternatives giving consideration to personnel safety, possible environmental damage, and possible facility well-equipment damage:

(1) Contain the well-fluid influx by shutting in the well and pumping the fluids back into the formation.

(2) Control the kick by using appropriate well-control techniques to prevent formation fracturing in an open hole within the pressure limits of the well equipment (drill pipe, work string, casing, wellhead, BOP system, and related equipment). The disposal of H_2S and other gases shall be through pressurized or atmospheric mud-gas separator equipment depending on volume, pressure, and concentration of H_2S. The equipment shall be designed to recover well-control fluids and to vent to the atmosphere and burn the gases separated from the well-control fluid. The well-control fluid shall be treated to neutralize H_2S and restore and maintain the proper quality.

(k) *Well testing in a zone known to contain H_2S.* (1) Prior to initiation of a well test, safety meetings shall be conducted for all personnel who will be on the facility during the test. The meetings shall emphasize the use of personnel protective-breathing apparatus, first-aid procedures, and the Contingency Plan. Only competent personnel who are trained and are knowledgeable of the hazardous effects of H_2S shall be engaged in these tests.

(2) Well testing shall be performed with the minimum number of personnel in the immediate vicinity of the rig floor and with the appropriate test equipment to safely and adequately perform the test. During the test, H_2S levels shall be continuously monitored.

(3) All produced gases shall be vented and burned through a flare which meets the requirements of paragraph (m)(7) of this section. Gases from stored test fluids shall be vented into the flare outlet.

(4) Downhole test tools and wellhead equipment shall be suitable for H_2S service.

(5) Tubulars suitable for H_2S service shall be used for well testing. Drill pipe shall not be used for well testing without the prior approval of the District Supervisor. Water cushions shall be thoroughly inhibited in order to prevent H_2S attack on metals. The test string shall be flushed with fluid treated for this purpose after completion of the test.

(6) All surface test units and related equipment shall be designed for H_2S service.

(l) *Metallurgical properties of equipment for use in a zone known to contain H_2S.*—(1) *General provisions.* Equipment used in H_2S environments shall be constructed of materials whose metallurgical properties resist or prevent sulfide stress cracking (also known as hydrogen embrittlement, stress corrosion cracking, and/or H_2S embrittlement). The metallurgical properties of the materials shall conform to National Association of Corrosion Engineers (NACE) Standard MR-01-75, Material Requirement, Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment.

(2) *Tubulars and other equipment.* Casing, tubing, drill pipe, couplings, flanges, and related equipment shall be designed for H_2S service as specified in Table 4, Acceptable API and American Society of Testing and Materials Specifications for Tubular Goods of NACE Standard MR–01–75. Approval of the District Supervisor is required prior to commencing field welding on such casing (except conductor and surface strings).

(3) *Wellhead, BOP System Components, and pressure-control equipment.* The BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H_2S-bearing fluids shall conform to NACE Standard MR–01–75. However, the BOP system components manufactured prior to April 1978, which are not in compliance with NACE Standard MR–01–75, may be used in an H_2S environment provided the BOP system components incorporate the manufacturer's own design considerations for H_2S service.

(4) *Downhole well-security equipment.* Temporary downhole well-security devices such as retrievable packers and bridge plugs shall be designed for H_2S service.

(5) *Production equipment.* Equipment used when producing zones bearing H_2S shall be constructed of materials capable of resisting or preventing sulfide stress cracking.

(6) *Installation or modification.* The use of welding shall be kept to a minimum during the installation or modification of the producing facility. Weldments shall be annealed and stress relieved according to the requirements of NACE Standard MR–01–75.

(m) *General requirements when operating in an H_2S zone*—(1) *Additional precautions after penetration of an H_2S-bearing zone.* The H_2S levels shall be continuously monitored in the work areas in addition to monitoring requirements in paragraph (h)(5)(i) of this section during the following operations:

(i) When it is necessary to pull a wet string of drill pipe or workover string,

(ii) Circulating bottoms-up after a drilling break,

(iii) Cementing operations,

(iv) Logging operations, and

(v) Circulating to condition mud or other well-control fluid.

(2) *Coring operations.* When conventional coring operations are conducted in H_2S-bearing zones, protective-breathing equipment shall be worn by those personnel in the working area at least 10 stands in advance of retrieving the core barrel. Cores to be transported shall be sealed and marked for the presence of H_2S.

(3) *Logging operations.* Well-control fluid in use for logging operations shall be conditioned and treated to minimize the effects of H_2S on the logging equipment.

(4) *Stripping operations.* Displaced well-control fluid returns shall be monitored, and protective-breathing equipment shall be worn by those personnel in the working area when the atmospheric concentration of H_2S reaches or exceeds 20 ppm or if the well is under pressure.

(5) *Gas-cut well-control fluid or well kick from H_2S-bearing zone.* Should a decision be made to circulate out a kick, protective-breathing equipment shall be worn by those personnel in the working area prior to and subsequent to bottoms-up and during an extended-kill operation.

(6) *Drill-string and workover-string design and precautions.* Drill- and workover-strings shall be designed consistent with the anticipated depth, conditions of the hole, and reservoir environment to be encountered. Care shall be taken to minimize exposure of the drill- or workover-string to high stresses as much as is practical and consistent with well conditions. Proper handling techniques shall be taken to minimize notching and stress concentrations. Precautions shall be taken to minimize stresses caused by doglegs, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint imbalance.

(7) *Flare system.* The flare outlet shall be of such diameter to allow easy nonrestricted flow of gas. Flare line outlets shall be located on the downwind side and as far from the facility as is feasible, taking into account the prevailing wind directions, the wake effects caused by the facility and adjacent structure(s), and the height of all such facilities and structures. The flare outlet shall be equipped with an automatic ignition system including a pilot-light gas source or an equivalent system. Alternate methods shall be available for igniting the flare. All vents from production process equipment, tanks, relief valves, burst plates, and similar devices shall be piped to the flare system used for H_2S.

(8) *Corrosion mitigation.* An effective means of monitoring and controlling corrosion caused by acid gases (H_2S and CO_2) shall be used in both the downhole and surface portions of a production system. Specific corrosion monitoring and mitigating measures shall be taken in areas of unusually severe corrosion where accumulation of water and/or higher concentrations of H_2S exist.

(9) *Wireline lubricators.* Lubricators which may be exposed to fluids containing shall be of H_2S-resistant materials.

(10) *Fuel and/or instrument gas.* Gas containing H_2S shall not be used for instrument gas. No gas containing H_2S shall be used for fuel gas without the prior approval of the District Supervisor.

(11) *Sensing lines and devices.* Metals used for sensing line and safety-control devices which are necessarily exposed to H_2S-bearing fluids shall be constructed of H_2S-corrosion resistant materials or coated with appropriate materials so as to resist H_2S corrosion.

(12) *Elastomer seals.* All seals which may be exposed to fluids containing H_2S shall be of H_2S-resistant materials.

(13) *Water disposal.* Produced water disposed of by means other than subsurface injection shall be treated for removal of H_2S.

(14) *Deck drains.* Open deck drains shall be equipped with traps or similar devices to prevent the escape of H_2S gas into the atmosphere.

(15) *Sealed voids.* Precautions shall be taken to eliminate sealed spaces in piping designs (e.g., slip-on flanges, reinforcing pads) which can be invaded by atomic hydrogen when H_2S is present.

Subpart E—Well-Completion Operations

§ 250.70 General requirements.

Well-completion operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

§ 250.71 Definition.

When used in this subpart, the following term shall have the meaning given below:

"Well-completion operations" mean the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

§ 250.72 Equipment movement.

The movement of well-completion rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed

master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a shut-in back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

§ 250.73 Emergency shutdown system.

When well-completion operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station.

§ 250.74 Hydrogen sulfide.

When a well-completion operation is conducted in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown (as defined in § 250.67 of this part), the lessee shall take appropriate precautions to protect life and property on the platform or completion unit, including, but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps, and packers. The lessee shall comply with the requirements in § 250.67 of this part as well as the appropriate requirements of this subpart.

§ 250.75 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Supervisor in accordance with § 250.83 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will adequately control the well and permit safe production operations.

§ 250.76 Crew instructions.

Prior to engaging in well-completion operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by MMS representatives.

§ 250.77 Welding and burning practices and procedures.

All welding, burning, and hot tapping activities involved in well-completion operations shall be conducted in accordance with the requirements in § 250.52 of this part.

§ 250.78 Electrical requirements.

All electrical equipment and systems involved in well-completion operations shall be designed, installed, equipped, protected, operated, and maintained in accordance with the requirements in § 250.53 of this part.

§ 250.79 Well-completion structures on fixed platforms.

Derricks, masts, substructures, and related equipment shall be selected, designed, installed, used, and maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the proposed operations. Prior to moving a well-completion rig or equipment onto a platform, the lessee shall determine the structural capability of the platform to safety support the equipment and proposed operations, taking into consideration the corrosion protection, age of platform, and previous stresses to the platform.

§ 250.80 Diesel engine air intakes.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic-shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic-shutdown devices.

§ 250.81 Traveling-block safety device.

After May 31, 1989, all units being used for well-completion operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.82 Field well-completion rules.

When geological and engineering information available in a field enables the District Supervisor to determine specific operating requirements, field well-completion rules may be established on the District Supervisor's initiative or in response to a request from a lessee. Such rules may modify the specific requirements of this subpart. After field well-completion rules have been established, well-completion operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field well-completion rules may be amended or canceled for cause at any time upon the initiative of the District Supervisor or upon the request of a lessee.

§ 250.83 Approval and reporting of well-completion operations.

(a) No well-completion operation shall begin until the lessee receives written approval from the District Supervisor. If completion is planned and the data are available at the time the Application for Permit to Drill, Form MMS–331C (see § 250.64 of this part), is submitted, approval for a well completion may be requested on that form. If the completion has not been approved or if the completion objective or plans have significantly changed, approval for such operations shall be requested on Form MMS–331, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–331 (or with Form MMS–331C):

(1) A brief description of the well-completion procedures to be followed, a statement of the expected surface pressure, and type and weight of completion fluids;

(2) A schematic drawing of the well showing the proposed producing zone(s) and the subsurface well-completion equipment to be used;

(3) For multiple completions, a partial electric log showing the zones proposed for completion, if logs have not been previously submitted; and

(4) When the well-completion is in a zone known to contain H_2S or a zone where the presence of H_2S is unknown, information pursuant to § 250.67 of this part.

(c) Within 30 days after completion, Form MMS–330, Well (Re)Completion Report, including a schematic of the tubing and subsurface equipment and the results of any well tests, shall be submitted to the District Supervisor.

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

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-completion operations and shall not be left unattended at any time unless the well is shut in and secured.

(b) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

(c) When coming out of the hole with drill pipe, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hole shall be utilized.

§ 250.85 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and BOP system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS–331 or Form MMS–331C, as appropriate, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-completion operations shall include the following:

(1) Three preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, one preventer equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(2) Four preventers, when the expected surface pressure is 5,000 psi or greater, or for multiple tubing strings consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams. When dual tubing strings are being handled simultaneously, dual pipe rams shall be installed on one of the pipe-ram preventers.

(3) When tapered drill string is used, the minimum BOP system shall include either of the following:

(i) Four preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, two sets of pipe rams, one capable of sealing around the larger size drill string and one capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for the two sets of pipe rams), and one preventer equipped with blind or blind shear rams; or

(ii) Five preventers, when the expected surface pressure is 5,000 psi or greater, consisting of an annular preventer, two sets of pipe rams capable of sealing around the larger size drill string, one set of pipe rams capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for one set of pipe rams capable of sealing around the larger size drill string and the set of pipe rams capable of sealing around the smaller size drill string), and a preventer equipped with blind or blind-shears rams.

(c) The BOP systems for well completions shall be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations of rig air is lost.

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

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

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

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

(d) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string.

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

(a) Prior to conducting high-pressure tests, all BOP system components shall be successfully tested to a low pressure of 200 psi to 300 psi. Ram-type BOP's, related control equipment, including the choke and kill manifolds, and safety valves shall be successfully tested to the rate working pressure of the BOP equipment or as otherwise approved by the District Supervisor. Variable bore rams shall be pressure-tested against all sizes of drill pipe in the well excluding drill collars. Surface BOP systems shall be pressure-tested with water. The annular BOP shall be successfully tested at 70 percent of its rated working pressure or as otherwise approved by the District Supervisor. Each valve in the choke and kill manifolds shall be successfully, sequentially pressure tested to the ram-type BOP test pressure.

(b) The BOP systems shall be tested at the following times:

(1) When installed.

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

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

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

(d) The time, dates, and results of BOP tests, actuations, and crew drills shall be recorded in the operations log.

§ 250.87 Tubing and wellhead equipment.

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Supervisor.

(c) When the tree is installed, the wellhead shall be equipped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the lessee shall immediately notify the District Supervisor.

(d) Wellhead, tree, and related equipment shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.121 of this part.

Subpart F—Well-Workover Operations

§ 250.90 General requirements.

Well-workover operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

§ 250.91 Definitions.

When used in this subpart, the following terms shall have the meanings given below:

"Workover operations" mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

"Routine operations" mean any of the following operations conducted on a well with the tree installed:

(a) Cutting paraffin;

(b) Removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations;

(c) Bailing sand;

(d) Pressure surveys;

(e) Swabbing;

(f) Scale or corrosion treatment;

(g) Caliper and gauge surveys;

(h) Corrosion inhibitor treatment;

(i) Removing or replacing subsurface pumps;

(j) Through-tubing logging (diagnostics);

(k) Wireline fishing; and

(l) Setting and retrieving other subsurface flow-control devices.

§ 250.92 Equipment movement.

The movement of well-workover rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-workover rigs and related equipment unless otherwise approved by the District Supervisor. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. The well to which a well-workover rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the tree and installing and testing the blowout-preventer (BOP) system. The well from which a well-workover rig or related equipment is to be moved shall also be equipped with a back pressure valve prior to removing the BOP system and installing the tree. Coiled tubing units, snubbing units, or wireline units may be moved onto a platform without shutting in wells.

§ 250.93 Emergency shutdown system.

When well-workover operations are conducted on a well with the tree removed, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station, except when there is no other hydrocarbon-producing well or other hydrocarbon flow on the platform.

§ 250.94 Hydrogen sulfide.

When a well-workover operation is conducted in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown (as defined in § 250.67 of this part), the lessee shall take appropriate precautions to protect life and property on the platform or rig, including but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps and packers. The lessee shall comply with the requirements in § 250.67 of this part as well as the appropriate requirements of this subpart.

§ 250.95 Subsea workovers.

No subsea well-workover operation including routine operations shall be commenced until the lessee obtains written approval from the District Supervisor in accordance with § 250.103 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will maintain adequate control of the well and permit continued safe production operations.

§ 250.96 Crew instructions.

Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by a Minerals Management Service representative.

§ 250.97 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities involved in well-workover operations shall be conducted in accordance with the requirements of § 250.52 of this part.

§ 250.98 Electrical requirements.

All electrical equipment and systems involved in well-workover operations shall be designed, installed, equipped, protected, operated, and maintained in accordance with the requirements in § 250.53 of this part.

§ 250.99 Well-workover structures on fixed platforms.

Derricks, masts, substructures, and related equipment shall be selected, designed, installed, used, and

maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the operations proposed. Prior to moving a well-workover rig or well-servicing equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and proposed operations, taking into consideration the corrosion protection, age of the platform, and previous stresses to the platform.

§ 250.100 Diesel engine air intakes.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated or automatic-manual shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

§ 250.101 Traveling-block safety device.

After May 31, 1989, all units being used for well-workover operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.102 Field well-workover rules.

When geological and engineering information available in a field enables the District Supervisor to determine specific operating requirements, field well-workover rules may be established on the District Supervisor's initiative or in response to a request from a lessee. Such rules may modify the specific requirements of this subpart. After field well-workover rules have been established, well-workover operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field well-workover rules may be amended or canceled for cause at any time upon the initiative of the District Supervisor or upon the request of a lessee.

§ 250.103 Approval and reporting for well-workover operations.

(a) No well-workover operation except routine ones, as defined in § 250.91 of this part, shall begin until the lessee receives written approval from the District Supervisor. Approval for such operations shall be requested on Form MMS–331, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–331:

(1) A brief description of the well-workover procedures to be followed, a statement of the expected surface pressure, and type and weight of workover fluids;

(2) When changes in existing subsurface equipment are proposed, a schematic drawing of the well showing the zone proposed for workover and the workover equipment to be used; and

(3) Where the well-workover is in a zone known to contain H_2S or a zone where the presence of H_2S is unknown, information pursuant to § 250.67 of this part.

(c) The following additional information shall be submitted with Form MMS–331 if completing to a new zone is proposed:

(1) Reason for abandonment of present producing zone including supportive well test data, and

(2) A statement of anticipated or known pressure data for the new zone.

(d) Within 30 days after completing the well-workover operation, except routine operations, Form MMS–331, Sundry Notices and Reports on Wells, shall be submitted to the District Supervisor, showing the work as performed. In the case of a well-workover operation resulting in the initial recompletion of a well into a new zone, a Form MMS–330, Well (Re)Completion Report, shall be submitted to the District Supervisor and shall include the results of any well tests and a new schematic of the tubing subsurface equipment if any subsurface equipment has been changed.

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

The following requirements apply during all well-workover operations with the tree removed:

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-workover operations and shall not be left unattended at anytime unless the well is shut in and secured.

(b) When coming out of the hole with drill pipe or a workover string, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe or workover string, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe or workover string and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hold shall be utilized.

(c) The following well-control-fluid equipment shall be installed, maintained, and utilized:

(1) A fill-up line above the uppermost BOP;

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

§ 250.105 Blowout prevention equipment.

(a) The BOP system, system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form MMS–331, requesting approval of the well-workover operation, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-workover operations with the tree removed shall include of the following:

(1) Three preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, one preventer equipped with pipe rams, and one preventer equipped with blind or blind-shear rams.

(2) Four preventers, when the expected surface pressure is 5,000 psi or greater, or for multiple tubing strings consisting of an annular preventer, two preventers equipped with pipe rams, and one preventer equipped with blind or blind-shear rams. When dual tubing strings are being handled simultaneously, dual pipe rams shall be installed on one of the pipe-ram preventers.

(3) When a tapered drill string is used, the minimum BOP system shall include either of the following:

(i) Four preventers, when the expected surface pressure is less than 5,000 psi, consisting of an annular preventer, two sets of pipe rams, one capable of sealing around the larger size drill string, and one capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for the two sets of pipe rams), and one preventer equipped with blind or blind-shear rams; or

(ii) Five preventers, when the expected surface pressure is 5,000 psi or greater, consisting of an annular preventer, two sets of pipe rams capable of sealing around the larger size drill string, one set of pipe rams capable of sealing around the smaller size drill string (one set of variable bore rams may be substituted for one set of pipe rams capable of sealing around the larger size drill string and the set of pipe rams capable of sealing around the smaller size drill string), and a preventer equipped with blind or blind-shear rams.

(c) The BOP systems for well-workover operations with the tree removed shall be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. No later than December 1, 1988, accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, shall be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations of rig air is lost;

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

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

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

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

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

(1) Two sets of pipe rams, and

(2) One set of blind rams.

(e) The minimum BOP-system components for well-workover operations with the tree in place and performed by manipulating spooled, nonjointed pipe through the wellhead, i.e., coiled-tubing operations, shall include the following:

(1) One set of pipe rams hydraulically operated,

(2) One two-way slip assembly hydraulically operated,

(3) One pipe-cutter assembly hydraulically operated,

(4) One set of blind rams hydraulically operated,

(5) One pipe-stripper assembly, and

(6) One spool with side outlets.

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

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

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

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

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

(a) Prior to conducting high-pressure tests, all BOP system components shall be successfully tested to a low pressure of 200 to 300 psi. Ram-type BOP's, related control equipment, including the choke and kill manifolds, and safety valves shall be successfully tested to the rated working pressure of the BOP equipment or as otherwise approved by the District Supervisor. Variable bore rams shall be pressure-tested against all sized of drill pipe in the well excluding drill collars. Surface BOP systems shall be pressure tested with water. The annular-type BOP shall be successfullly tested at 70 percent of its rated working pressure or as otherwise approved by the District Supervisor. Each valve in the choke and kill manifolds shall be successfully, sequentially pressure tested to the ram-type BOP test pressure.

(b) The BOP systems shall be tested at the following times:

(1) When installed;

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

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

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

(d) The time, dates, and results of the BOP tests, actuations, and crew drills shall be recorded in the operations log.

§ 250.107 Tubing and wellhead equipment.

The lessee shall comply with the following requirements during well-workover operations with the tree removed:

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure tested, calipered, or otherwise

evaluated every 30 days and the results submitted to the District Supervisor.

(c) When reinstalling the tree, the wellhead shall be equiped so that all annuli can be monitored for sustained pressure. If sustained casing pressure is observed on a well, the lessee shall immediately notify the District Supervisor.

(d) Wellhead, tree, and related equipment shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. The tree shall be equipped with a minimum of one master valve and one surface safety valve in the vertical run of the tree when it is reinstated.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.121 of this part.

§ 250.108 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in § 250.91 of this part, and nonroutine wireline workover operations:

(a) Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

(b) All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.

(c) When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

Subpart G—Abandonment of Wells

§ 250.110 General requirements.

The lessee shall abandon all wells in a manner to assure downhole isolation of hydrocarbon zones, protection of freshwater aquifers, clearance of sites so as to avoid conflict with other uses of the Outer Continental Shelf (OCS), and prevention of migration of formation fluids within the wellbore or to the seafloor. Any well which is no longer used or useful for lease operations shall be plugged and abandoned in accordance with the provisions of this subpart. However, no production well shall be abandoned until its lack of capacity for further profitable production of oil, gas, or sulphur has been demonstrated to the satisfaction of the District Supervisor. No well shall be plugged if the plugging operations would jeopardize safe and economic operations of nearby wells, unless the well poses a hazard to safety or the environment.

§ 250.111 Approvals.

The lessee shall not commence abandonment operations without prior approval of the District Supervisor. The lessee shall submit a request on Form MMS–332, Notice of Intent/Report of Well Abandonment, for approval to abandon a well and a subsequent report of abandonment within 30 days from completion of the work in accordance with the following:

(a) *Notice of Intent to Abandon Well.* A request for approval to abandon a well shall contain the reason for abandonment including supportive well logs and test data, a description and schematic of proposed work including depths, type, location, length of plugs, the plans for mudding, cementing, shooting, testing, casing removal, and other pertinent information.

(b) *Subsequent report of abandonment.* The subsequent report of abandonment shall include a description of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging, and all information listed in paragraph (a) of this section with a revised schematic. If an attempt was made to cut and pull any casing string, the subsequent report shall include a description of the methods used, size of casing removed, depth of the casing removal point, and the amount of the casing removed from the well.

§ 250.112 Permanent abandonment.

(a) *Isolation of zones in open hole.* In uncased portions of wells, cement plugs shall be set to extend from a minimum of 100 feet below the bottom to 100 feet above the top of any oil, gas, or freshwater zones to isolate fluids in the strata in which they are found and to prevent them from escaping into other strata or to the seafloor. The placement of additional cement plugs to prevent the migration of formation fluids in the wellbore may be required by the District Supervisor.

(b) *Isolation of open hole.* Where there is an open hole below the casing, a cement plug shall be placed in the deepest casing by the displacement method and shall extend a minimum of 100 feet above and 100 feet below the casing shoe. In lieu of setting a cement plug across the casing shoe, the following methods are acceptable:

(1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the casing shoe. The cement plug shall extend at least 100 feet below the casing shoe and at least 50 feet above the retainer.

(2) If lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed within the first 150 feet above the casing shoe with a minimum of 50 feet of cement on top of the bridge plug. This bridge plug shall be tested in accordance with paragraph (g) of this section.

(c) *Plugging or isolating perforated intervals.* A cement plug shall be set by the displacement method opposite all perforations which have not been squeezed with cement. The cement plug shall extend a minimum of 100 feet above the perforated interval and either 100 feet below the perforated interval or down to a casing plug, whichever is the lesser. In lieu of setting a cement plug by the displacement method, the following methods are acceptable, provided the perforations are isolated from the hole below:

(1) A cement retainer and a cement plug shall be set. The cement retainer shall have effective back-pressure control and shall be set not less than 50 feet and not more than 100 feet above the top of the perforated interval. The cement plug shall extend at least 100 feet below the bottom of the perforated interval with 50 feet placed above the retainer.

(2) A permanent-type bridge plug shall be set within the first 150 feet above the top of the perforated interval with at least 50 feet of cement on top of the bridge plug.

(3) A cement plug which is at least 200 feet long shall be set by the displacement method with the bottom of the plug within the first 100 feet above the top of the perforated interval.

(d) *Plugging of casing stubs.* If casing is cut and recovered leaving a stub, the stub shall be plugged in accordance with one of the following methods:

(1) A stub terminating inside a casing string shall be plugged with a cement plug extending at least 100 feet above and 100 feet below the stub. In lieu of setting a cement plug across the stub, the following methods are acceptable:

(i) A cement retainer or a permanent-type bridge plug shall be set not less than 50 feet above the stub and capped with at least 50 feet of cement, or

(ii) A cement plug which is at least 200 feet long shall be set with the bottom of the plug within 100 feet above the stub.

(2) If the stub is below the next larger string, plugging shall be accomplished as required to isolate zones or to isolate an open hole as described in paragraphs (a) and (b) of this section.

(e) *Plugging of annular space.* Any annular space communicating with any open hole and extending to the mud line shall be plugged with at least 200 feet of cement.

(f) *Surface plug.* A cement plug which is at least 150 feet in length shall be set with the top of the plug within the first 150 feet below the mud line. The plug shall be placed in the smallest string of casing which extends to the mud line.

(g) *Testing of plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

(1) The lessee shall place a minimum pipe weight of 15,000 pounds on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer is not required to be tested.

(2) The lessee shall test the plug with a minimum pump pressure of 1,000 pounds per square inch with a result of no more than a 10-percent pressure drop during a 15-minute period.

(h) *Fluid left in hole.* Each of the respective intervals of the hole between the various plugs shall be filled with fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure in the intervals between the plugs at time of abandonment.

(i) *Clearance of location.* All wellheads, casings, pilings, and other obstructions shall be removed to a depth of at least 15 feet below the mud line or to a depth approved by the District Supervisor. The lessee shall verify that the location has been cleared of all obstructions in accordance with § 250.114 of this part. The requirement for removing subsea wellheads or other obstructions and for verifying location clearance may be reduced or eliminated when, in the opinion of the District Supervisor, the wellheads or other obstructions would not constitute a hazard to other users of the seafloor or other legitimate uses of the area.

(j) *Requirements for permafrost areas.* The following requirements shall be implemented for permafrost areas:

(1) Fluid left in the hole adjacent to permafrost zones shall have a freezing point below the temperature of the permafrost and shall be treated to inhibit corrosion.

(2) The cement used for cement plugs placed across permafrost zones shall be designed to set before freezing and to have a low heat of hydration.

§ 250.113 Temporary abandonment.

(a) Any drilling well which is to be temporarily abandoned shall meet the requirements for permanent abandonment (except for the provisions in §§ 250.112 (f) and (i), and 250.114) and the following:

(1) A bridge plug or a cement plug at least 100 feet in length shall be set at the base of the deepest casing string unless the casing string has been cemented and has not been drilled out. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole.

(2) A retrievable or a permanent-type bridge plug or a cement plug at least 100 feet in length, shall be set in the casing within the first 200 feet below the mud line.

(b) Subsea wellheads, casing stubs, or other obstructions above the seafloor remaining after temporary abandonment will be protected in such a manner as to allow commercial fisheries gear to pass over the structure without damage to the structure or fishing gear. Depending on water depth, nature and height of obstruction above the seafloor, and the types and periods of fishing activity in the area, the District Supervisor may waive this requirement.

(c) In order to maintain the temporarily abandoned status of a well, the lessee shall provide, within 1 year of the original temporary abandonment and at successive 1-year intervals thereafter, an annual report describing plans for reentry to complete or permanently abandon the well.

(d) Identification and reporting of subsea wellheads, casing stubs, or other obstructions extending above the mud line will be accomplished in accordance with the requirements of the U.S. Coast Guard.

§ 250.114 Site clearance verification.

(a) The lessees shall verify site clearance after abandonment by one or more of the following methods as approved by the District Supervisor:

(1) Drag a trawl in two directions across the location,

(2) Perform a diver search around the wellbore,

(3) Scan across the location with a side-scan or on-bottom scanning sonar, or

(4) Use other methods based on particular site conditions.

(b) Certification that the area was cleared of all obstructions, the date the work was performed, the extent of the area searched around the location, and the search method utilized shall be submitted with Form MMS–332.

Subpart H—Production Safety Systems

§ 250.120 General requirements.

Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety and protection of the human, marine, and coastal environments. Production safety systems operated in subfreezing climates shall utilize equipment and procedures selected with consideration of floating ice, icing, and other extreme environmental conditions that may occur in the area. Production shall not commence until the production safety system has been approved and a preproduction inspection has been requested by the lessee.

§ 250.121 Subsurface safety devices.

(a) *General.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after application and justification, the well is determined by the District Supervisor to be incapable of natural flowing. These devices may consist of a surface-controlled subsurface safety valve (SSSV), a subsurface-controlled SSSV, an injection valve, a tubing plug, or a tubing/annular subsurface safety device, and any associated safety valve lock or landing nipple.

(b) *Specifications for SSSV's.* Surface-controlled and subsurface-controlled SSSV's and safety valve locks and landing nipples installed in the OCS shall conform to the requirements in § 250.126 of this part.

(c) *Surface-controlled SSSV's.* All tubing installations open to a hydrocarbon-bearing zone which is capable of natural flow shall be equipped with a surface-controlled SSSV, except as specified in paragraphs (d), (f), and (g) of this section. The surface controls may be located on the site or a remote location. Wells not previously equipped with a surface-controlled SSSV and wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV in accordance with paragraph (d)(2) of this section shall be equipped with a surface-controlled SSSV when the tubing is first removed and reinstalled.

(d) *Subsurface-controlled SSSV's.* Wells may be equipped with subsurface-controlled SSSV's in lieu of a surface-controlled SSSV provided the lessee demonstrates to the District Supervisor's satisfaction that the following criteria are met:

(1) Wells not previously equipped with surface-controlled SSSV's shall be so equipped when the tubing is first removed and reinstalled,

(2) The subsurface-controlled SSSV is installed in wells completed from a

single-well or multiwell satellite caisson or seafloor completions, and

(3) The subsurface-controlled SSSV is installed in wells with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing.

(e) *Design, installation, and operation of SSSV's.* The SSSV's shall be designed, installed, operated, and maintained to ensure reliable operation.

(1) The device shall be installed at a depth of 100 feet or more below the seafloor within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffins, an alternate setting depth of the subsurface safety device may be approved by the District Supervisor.

(2) Until a subsurface safety device is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

(3) The well shall not be open to flow while the subsurface safety device is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.

(4) All SSSV's shall be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, and Operation of Subsurface Safety Valve Systems.

(f) *Subsurface safety devices in shut-in wells.* New completions (perforated but not placed on production) and completions shut in for a period of 6 months shall be equipped with either (1) a pump-through-type tubing plug; (2) a surface-controlled SSSV, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow. The setting depth of the subsurface safety device shall be approved by the District Supervisor on a case-by-case basis, when warranted by conditions such as permafrost, unstable bottom conditions, hydrate formations, and paraffins.

(g) *Subsurface safety devices in injection wells.* A surface-controlled SSSV or an injection valve capable of preventing backflow shall be installed in all injection wells. This requirement is not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually.

(h) *Temporary removal for routine operations.* (1) Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Form MMS–331, Sundry Notices and Reports on Wells, in § 250.91 of this part for a period not to exceed 15 days.

(2) The well shall be identified by a sign on the wellhead stating that the subsurface safety device has been removed. The removal of the subsurface safety device shall be noted in the records as required in § 250.124(b) of this part. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.

(3) A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless otherwise approved by the District Supervisor.

(4) The well shall not be allowed to flow while the subsurface safety device is removed, except when flowing the well is necessary for that particular operation. The provisions of this paragraph are not applicable to the testing and inspection procedures in § 250.124 of this part.

(i) *Additional safety equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface safety device is installed after the effective date of this subpart shall be equipped with a landing nipple with flow couplings or other protective equipment above and below to provide for the setting of the SSSV. The control system for all surface-controlled SSSV's shall be an integral part of the platform Emergency Shutdown System (ESD). In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled SSSV's shall close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

(j) *Emergency action.* In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

§ 250.122 Design, installation, and operation of surface production-safety systems.

(a) *General.* All production facilities, including separators, treaters, compressors, headers, and flowlines shall be designed, installed, and maintained in a manner which provides for efficiency, safety of operation, and protection of the environment.

(b) *Platforms.* All platform production facilities shall be protected with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with the provisions of API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms. If processing components are to be utilized, other than those for which Safety Analysis Checklists are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system. Safety device requirements for pipelines are contained in § 250.154 of this part.

(c) *Specification for surface safety valves (SSV) and underwater safety valves (USV).* All wellhead SSV's, USV's, and their actuators which are installed in the OCS shall conform to the requirements in § 250.126 of this part.

(d) *Use of SSV's and USV's.* All SSV's and USV's shall be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Use of Surface Safety Valves and Underwater Safety Valves Offshore. If any SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(e) *Approval of safety-systems design and installation features.* Prior to installation, the lessee shall submit, in duplicate for approval to the District Supervisor a production safety system application containing information relative to design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or other location conveniently available to the District Supervisor. All approvals are subject to field verifications. The application shall include the following:

(1) A schematic flow diagram showing tubing pressure, size, capacity, design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, pipeline pumps, metering

devices, and other hydrocarbon-handling vessels.

(2) A schematic flow diagram (API RP 14C, Figure E1) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c).

(3) A schematic piping diagram showing the size and maximum allowable working pressures as determined in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems.

(4) Electrical system information including the following:

(i) A plan of each platform deck outlining all hazardous areas classified in accordance with API RP 500B, Recommended Practice for Classification of Locations for Electrical Installations at Drilling Rigs and Production Facilities on Land and on Marine Fixed and Mobile Platforms and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outline shall include the following information:

(A) All major production equipment, wells, and other significant hydrocarbon sources and a description of the type of decking, ceiling, walls (e.g., grating or solid) and firewalls; and

(B) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (e.g., type cable, conduit, or wire).

(ii) Elementary electrical schematic of any platform safety shut-down system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that new installations conform to the approved designs of this subpart.

(6) The design and schematics of the installation and maintenance of all fire- and gas-detection systems shall include the following:

(i) Type, location, and number of detection sensors;

(ii) Type and kind of alarms, including emergency equipment to be activated;

(iii) Method used for detection;

(iv) Method and frequency of calibration; and

(v) A functional block diagram of the detection system, including the electric power supply.

§ 250.123 Additional production system requirements.

(a) *General.* Lessees shall comply with the following production safety system requirements (some of which are in addition to those contained in API RP 14C), incorporated by reference in § 250.122(b) of this part.

(b) *Design, installation, and operation of additional production systems*—(1) *Pressure and fired vessels.* Pressure and fired vessels shall be designed, fabricated, code stamped, and maintained in accordance with applicable provisions of Sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. All existing uncoded vessels in use must be justified and approval for continued use obtained from the District Supervisor no later than June 30, 1988.

(i) Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of Sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves, except completely redundant relief valves, shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) Steam generators operating at less than 15 pounds per square inch gauge (psig) shall be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. Steam generators operating at greater than 15 psig require, in addition to an LSL, a water-feeding device which will automatically control the water level.

(iii) The lessee shall use pressure recorders to establish the new operating pressure ranges of pressure vessels at any time when there is a significant change in operating pressures. The pressure-recorder charts used to determine current operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Supervisor. The high-pressure shut-in sensor shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the vessel. This setting shall also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut in before the relief valve activates. The low-pressure shut-in sensor shall activate no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range. The activation of low-pressure sensors on pressure vessels which operate at less than 5 psi shall be approved by the District Supervisor on a case-by-case basis.

(2) *Flowlines.* (i) Flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located in accordance with section A.1 and Figure A1 of API RP 14C. The lessee shall use pressure recorders to establish the new operating pressure ranges of flowlines at any time when there is a significant change in operating pressures. The most recent pressure-recorder charts used to determine operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Supervisor. The high-pressure shut-in sensor(s) shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the line. But in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the SSV. The low-pressure shut-in sensor(s) shall be set no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the line in which it is installed.

(ii) If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) shall have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(A) A relief valve which vents into the platform flare scrubber or some other location approved by the District Supervisor. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid hydrocarbons which may be relieved to the vessel.

(B) Two SSV's with independent high-pressure sensors installed with adequate volume upstream of any block valve to allow sufficient time for the valve(s) to close before exceeding the maximum allowable working pressure.

(3) *Safety sensors.* All shutdown devices, valves, and pressure sensors shall function in a manual reset mode. Sensors with integral automatic reset shall be equipped with an appropriate device to override the automatic reset mode. All pressure sensors shall be equipped to permit testing with an external pressure source.

(4) *ESD.* The ESD shall conform to the requirements of Appendix C, section C1, of API RP 14C, and the following:

(i) The manually operated ESD valve(s) shall be quick-opening and

nonrestricted to enable the rapid actuation of the shutdown system. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve.

(ii) Closure of the SSV shall not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV shall close in not more than 2 minutes after the shut-in signal has closed the SSV. Design-delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and be approved by the District Supervisor.

(iii) A schematic of the ESD which indicates the control functions of all safety devices for the platforms shall be maintained by the lessee on the platform or at the lessee's field office nearest the OCS facility or other location conveniently available to the District Supervisor.

(5) *Engines*—(i) *Engine exhaust.* Engine exhausts shall be equipped to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4). Exhaust piping from diesel engines shall be equipped with spark arresters.

(ii) *Diesel engine air intake.* No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shutdown the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

(6) *Glycol dehydration units.* A pressure relief system or an adequate vent shall be installed on the glycol regenerator (reboiler) which will prevent overpressurization. The discharge of the relief valve shall be vented in a nonhazardous manner.

(7) *Gas compressors.* Compressor installations shall be equipped with the following protective equipment as required in API RP 14C, section A8.

(i) A Pressure Safety High (PSH), a Pressure Safety Low (PSL), a Pressure Safety Valve (PSV), and a Level Safety High (LSH), and an LSL to protect each interstage and suction scrubber.

(ii) A Temperature Safety High (TSH) on each compressor discharge cylinder.

(iii) The PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic shutdown valves (SDV) located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Supervisor, gas-well gas affected by the closure of the automatic SDV on a compressor suction shall be diverted to the pipeline or shut in at the wellhead.

(iv) A blowdown valve is required on the discharge line of all compressor installations of 1,000 horsepower (746 kilowatts) or greater.

(8) *Firefighting systems.* Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons shall conform to subsection 5.2, Firewater systems, of API RP 14G, Fire Prevention and Control Open Type Offshore Production Platforms, and shall require approval of the District Supervisor. The following additional requirements shall apply for both open- and closed-production platforms:

(i) A firewater system consisting of rigid pipe with firehose stations or fixed firewater monitors shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed waterspray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during a platform shut-in. If necessary, an alternate fuel or power supply shall be installed to provide for this pump-operating time unless an alternate firefighting system has been approved by the District Supervisor.

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Supervisor determines that the use of a chemical system provides equivalent fire-protection control.

(iv) A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the facility or structure.

(v) For operations in subfreezing climates, the lessee shall furnish evidence to the District Supervisor that the firefighting system is suitable for the conditions.

(9) *Fire- and gas-detection system.* (i) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas. Gas sensors shall be installed in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation which is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit (LEL). One approved method of providing adequate ventilation is a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than grating or fixed open louvers and of sufficient size to allow entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500B.

(ii) All detection systems shall be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(iii) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(iv) The District Supervisor may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems shall be an approved type, designed and installed in accordance with API RP 14C, API RP 14G, and API RP 14F, Design and Installation of Electrical Systems for Offshore Production Platforms.

(10) *Electrical equipment.* Electrical equipment and systems shall be designed, installed, and maintained in accordance with the requirements in § 250.53 of this part.

(11) *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. Records by lease, indicating the wells which have erosion-control programs in effect and the results of the programs, shall be maintained by the lessee for a period of 2 years and shall be made available to MMS upon request.

(c) *General platform operations.* (1) Surface or subsurface safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service shall be flagged.

(2) When wells are disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed, compliance is not required with the provisions of API RP 14C or this regulation concerning the following:

(i) Automatic fail-close SSV's on wellhead assemblies, and

(ii) The PSH and PSL shut-in sensors in flowlines from wells.

(3) When pressure or atmospheric vessels are isolated from production facilities (e.g., inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device compliance with API RP 14C or this subpart is not required.

(4) All open-ended lines connected to producing facilities and wells shall be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(d) *Welding and burning practices and procedures.* All welding, burning, and hot-tapping activities shall be conducted according to the specific requirements in § 250.52 of this part.

§ 250.124 Production safety-system testing and records.

(a) *Inspection and testing.* The safety-system devices shall be successfully inspected and tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing shall be in accordance with API RP 14C, Appendix D, and the following:

(1) Testing requirements for subsurface safety devices are as follows:

(i) Each surface-controlled subsurface safety device installed in a well, including such devices in shut-in and injection wells, shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, or if a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. Testing shall be in accordance with API RP 14B to ensure proper operation.

(ii) Each subsurface-controlled SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple. If a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced.

(iii) Each tubing plug installed in a well shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.

(iv) Injection valves shall be tested in the manner as outlined for testing tubing plugs in paragraph (a)(1)(iii) of this section. Leakage rates outlined in paragraph (a)(1)(iii) of this section shall apply.

(2) All PSV's shall be tested for operation at least once every 12 months. These valves shall be either bench-tested or equipped to permit testing with an external pressure source. Weighted disk vent valves used as PSV's on atmospheric tanks may be disassembled and inspected in lieu of function testing.

(3) The following safety devices shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests:

(i) All PSH or PSL,

(ii) All LSH and LSL controls,

(iii) All automatic inlet SDV's which are actuated by a sensor on a vessel or compressor, and

(iv) All SDV's in liquid discharge lines and actuated by vessel low-level sensors.

(4) All SSV's and USV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The testing shall be in accordance with the test procedures specified in API RP 14H, Section 4, Table 2. If the SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(5) All flowline Flow Safety Valves (FSV) shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedure specified in API RP 14C, Appendix D, section D4, Table D2, subsection D. If the leakage measured exceeds a liquid flow of 200 cubic centimeters per minute or a gas flow of 5 cubic feet per minute, the FSV's shall be repaired or replaced.

(6) The TSH shutdown controls installed on compressor installations which can be nondestructively tested shall be tested every 6 months and repaired or replaced as necessary.

(7) All pumps for firewater systems shall be inspected and operated weekly.

(8) All fire- (flame, heat, or smoke) detection systems shall be tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner. Open flame or devices operating at temperatures which could ignite a methane-air mixture shall not be used. All combustible gas-detection systems shall be calibrated every 3 months.

(9) All TSH devices shall be tested at least once every 12 months, excluding those addressed in paragraph (a)(6) of this section and those which would be destroyed by testing. Burner safety low and flow safety low devices shall also be tested at least once every 12 months.

(10) The ESD shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The test shall be conducted by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation.

(11) Prior to the commencement of production, the lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a complete inspection may be conducted.

(b) *Records.* The lessee shall maintain records for a period of 2 years for each subsurface and surface safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or other locations conveniently available to the District Supervisor. These records shall be available for review by a representative of MMS. The records shall show the present status and history of each device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

§ 250.125 Safety device training.

Personnel installing, inspecting, testing, and maintaining these safety devices and personnel operating the production platforms shall be qualified in accordance with subpart O.

§ 250.126 Quality assurance and performance of safety and pollution prevention equipment.

(a) Safety and pollution prevention equipment installed on the OCS shall meet the quality assurance requirements identified in paragraph (c) of this section. The MMS will consider approval of other quality assurance programs for the manufacture of safety and pollution prevention equipment. Quality assurance programs proposed for consideration by MMS shall be submitted to the Deputy Associate Director for Offshore Operations; Minerals Management Service; Mail Stop 647; 12203 Sunrise Valley Drive; Reston, Virginia 22091.

(b)(1) By June 30, 1988, each lessee shall submit to the Deputy Associate Director for Offshore Operations a list of all certified and noncertified SSV's (both actuator and valve), USV's (both actuator and valve), and SSSV's (including safety valve locks and landing nipples) in the lessee's inventory as of June 30, 1988. The list shall indicate which items of the safety and pollution-prevention equipment were manufactured under American National Standards Institute/American Society of Mechanical Engineers Standard ANSI/ASME SPPE–1, Quality Assurance and Certification of Safety and Pollution-Prevention Equipment Used in Offshore Oil and Gas Operations and shall identify each listed item by manufacturer, serial number, model, the date the item entered inventory, and whether the item is in service on the OCS or in stock for installation on the OCS.

(2) Lists received from lessees under paragraph (b)(1) of this section shall be maintained by MMS. An SSSV shall be removed from the list when it is removed from service for a failure or malfunction. A USV or an SSV shall be removed from the list when it is removed from service for remanufacture (repairs employing machining, welding, heat treating, or other manufacturing operations). Lessees shall notify the Deputy Associate Director for Offshore Operations when an SSSV is removed from service for a failure or malfunction or a USV or SSV is removed from service for remanufacture (repairs employing machining, welding, heat treating, or other manufacturing operations).

(c) Safety and pollution-prevention equipment used in the OCS shall meet one of the following:

(1) Be identified on the list submitted under paragraph (b) of this section by a lessee of the lease on which the item is to be installed, or

(2) Be certified by the manufacturer as having been produced under a quality assurance program that meets ANSI/ASME SPPE–1 or an alternate program approved by MMS. The installation, inspection, maintenance, testing, removal, field repair, remanufacture, and documentation of SPPE–1 certified safety and pollution-prevention equipment shall be in accordance with the applicable standard in Appendix I, Referenced Standards.

§ 250.127 Hydrogen sulfide.

Production operations in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown, as defined in § 250.67 of this part, shall be conducted in accordance with that section and other relevant requirements of Subpart H, Production Safety Systems.

Subpart I—Platforms and Structures

§ 250.130 General requirements.

(a) The lessee shall design, fabricate, install, use, inspect, and maintain all platforms and structures (platforms) on the Outer Continental Shelf (OCS) to assure their structural integrity for the safe conduct of drilling, workover, and production operations, considering the specific environmental conditions at the platform location.

(b) All new fixed or bottom-founded platforms (i.e., platforms or other structures, e.g., single-well caissons, artificial islands), shall be designed, fabricated, installed, inspected, and maintained in accordance with all the requirements of this section and §§ 250.131 and 250.134 through 250.144 of this subpart. Applications submitted pursuant to § 250.131 shall require the approval by the Regional Supervisor prior to platform installation.

(c) All new platforms which meet any of the conditions listed below shall be subject to the Platform Verification Program and shall be designed, fabricated, and installed in accordance with the requirements of §§ 250.131 through 250.144 of this part.

(1) Platforms installed in water depths exceeding 400 feet,

(2) Platforms having natural periods in excess of 3 seconds,

(3) Platforms installed in areas of unstable bottom conditions,

(4) Platforms having configurations and designs which have not previously been used or proven for use in the area, or

(5) Platforms installed in seismically active areas.

(d) Major modification to any platform shall be subject to the requirements of this subpart and shall require the approval of the Regional Supervisor. Major modification means any structural changes which materially alter the approved plan or causes a major deviation from approved operations.

(e)(1) Major repairs of damage to any platform shall require the prior approval of the Regional Supervisor. Major repairs of damage means corrective operations involving structural members affecting the structural integrity of a portion or all of the platform.

(2) Under emergency conditions, repairs to primary structural elements may be made to restore an existing permitted condition without prior approval. The Regional Supervisor shall be notified within 24 hours of the damage that occurred and repairs that were made. The Regional Supervisor's approval for repairs shall be obtained.

(f) The requirements for an application for approval for the reuse or conversion of the use of an existing fixed or mobile platforms shall be determined on a case-by-case basis. An application shall be submitted to the Regional Supervisor for approval and shall include location, intended use, and demonstrate the adequacy of the design and structural condition of the platform.

(g) In addition to the requirements of this subpart, platform design, fabrication, and installation shall conform to API RP 2A, Recommended Practice For Planning, Designing, And Constructing Fixed Offshore Platforms, or American Concrete Institute (ACI) 357R, Guide for the Design and Construction of Fixed Offshore Concrete Structures, as appropriate. Alternative codes or rules may be utilized with approval of the Regional Supervisor. The requirements contained in these documents (API RP 2A and ACI 357R) are incorporated herein insofar as they do not conflict with other provisions of this subpart.

§ 250.131 Application for approval.

(a) All applications under the provisions of this subpart shall be submitted to the Regional Supervisor for approval. All significant changes or modifications to approved applications shall be submitted to the Regional Supervisor for approval.

(b) Applications for all new platforms or major modifications shall be

submitted in triplicate and shall contain the following information:

(1) General platform information including the following:

(i) The platform designation, lease number, area name, and block number;

(ii) Longitude and latitude coordinates, Universal Transverse Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 inch = 2,000 feet showing surface location of the platform and distance from the nearest block lines;

(iii) Drawings, plats, front and side elevations of the entire platform, and plan views that clearly illustrate essential parts, i.e., number and location of well slots, design loadings of each deck, water depth, nominal size and thickness of all primary load-bearing jacket and deck structural members, and nominal size, makeup, thickness, and design penetration of piling;

(iv) Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones; and

(v) In the Alaska OCS Region, the following additional information shall be submitted:

(A) Slope protection and berm elevation for manmade islands,

(B) Wall thickness with size and placement of major steel reinforcement for concrete-gravity structures,

(C) Shell thickness with size and location of major reinforcement members for steel-gravity structures, and

(D) A plan for periodic inspections of the installed platforms in accordance with § 250.142 of this part.

(2) A summary of environmental data, as addressed in § 250.134 of this part, which has a bearing on the platform's design, installation, and operation, e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures;

(3) Foundation information including the following:

(i) A geotechnical investigation report containing a brief summary of the major strata encountered at the location by bore holes presented in tabular form, a detailed subsurface profile illustrating results of field and laboratory testing, a listing of field and laboratory investigations and tests with a basic summary of resultant determinations, the identification of properties and conditions of the seabed and the subsoil, and the identification of any manmade hazards or obstructions;

(ii) A description of the effect of the environmental and functional loads on the foundation;

(iii) A determination, with supporting information, of the susceptibility of the area to soil movement and, if susceptible, an analysis of slope and soil stability;

(iv) A summary of the foundation design criteria as specified in § 250.139 of this part; and

(v) A summary of the seafloor survey results specified in § 250.139(b)(2) of this part.

(4) Structural information including the following:

(i) The design life of the platform and the basis for such determination.

(ii) A summary description of the design load conditions and design load combinations, taking into consideration the worst environmental and operational conditions anticipated over the service life of the platform.

(iii) A listing and description of the appropriate material specifications.

(iv) A description of the design methodologies, e.g., elastic, inelastic, and ultimate strength, used in design of the platform.

(v) A summary of pertinent derived factors of safety against failure for major structural members, e.g., unity check ratios exceeding 0.85 for steel-jacket platform members, indicated on "line" sketches of jacket sections.

(vi)(A) In the Alaska, Atlantic, and Pacific OCS Regions, a summary of the fatigue analysis as specified in §§ 250.135 through 250.139 of this part. The specific requirements for a fatigue analysis shall be determined by the Regional Supervisor on a case-by-case basis to determine the adequacy of the design and to assure the structural integrity of the platform.

(B) In the Gulf of Mexico OCS Region, a summary of the fatigue analysis as specified in §§ 250.135 through 250.139 of this part. A fatigue analysis shall be performed for each steel template, pile-supported platform with natural periods greater than 3 seconds, and for each platform to be fabricated of high-strength steel (i.e., over 50 thousand pounds per square inch minimum yield) where components of high-strength steel are subjected to cyclic loading. The specific requirements for a fatigue analysis for other platforms shall be determined by the Regional Supervisor on a case-by-case basis to determine adequacy of the design and to assure the structural integrity of the platform.

(c) The information shall be submitted with or subsequent to the submittal of an Exploration Plan or Development and Production Plan. Additional detailed data and information may be required by the Regional Supervisor when needed to determine the adequacy of the design.

(d) The lessee shall have detailed structural plans as called for in paragraph (b)(1)(iii) of this section and specifications for new platforms or other structures and major modifications certified by a registered professional structural engineer or civil engineer specializing in structural design. The lessee shall also sign, date, and submit the following certification Lessee certifies that the design of the structure/modification has been certified by a registered professional structural or a civil engineer specializing in structural design, and the structure/modification will be fabricated, installed, and maintained as described in the application and any approved modification thereto. Certified design and as built plans and specifications will be on file at .

(e) The lessee shall notify the Regional Supervisor at least 1 week prior to transporting the platform to the installation site.

§ 250.132 Platform Verification Program requirements.

(a) *Requirements.* These requirements apply to the design, fabrication, and installation of new, fixed, bottom-founded, pile-supported, or concrete-gravity platforms. The applicability of these requirements to other types of platforms shall be determined by the MMS on a case-by-case basis. For all new platforms or major modifications which meet any of the conditions contained in § 250.130(c) of this part, the lessee shall submit the design, fabrication, and installation verification plans to the Regional Supervisor for approval in accordance with paragraph (b) of this section. The design plan shall be submitted with or subsequent to the submittal of an Exploration Plan or Development and Production Plan. The fabrication and installation plans shall be submitted and approval obtained before such operations are initiated.

(b) *Verification plan requirements*—(1) *General plan requirements.* Each verification plan shall be submitted in triplicate and include the following:

(i) A nomination of a Certified Verification Agent (CVA) who shall conduct specified reviews in accordance with § 250.133 of this part,

(ii) The CVA qualification statement consisting of the following:

(A) Previous experience in third-party verification or experience in the design, fabrication, and/or installation of

offshore oil and gas platforms, manmade islands, or other marine structures;

(B) Technical capabilities of the individual or the primary staff to be associated with the CVA functions for the specific project;

(C) Size and type of organization or corporation;

(D) In-house availability of, or access to, appropriate technology, i.e., computer programs and hardware and testing materials and equipment;

(E) Ability to perform the CVA functions for the specific project considering current commitments; and

(F) Previous experience with MMS requirements and procedures.

(iii) The level of work to be performed by the CVA, and

(iv) A list of documents to be furnished to the CVA.

(2) *Design verification plan requirements.* The design plan shall also include the following:

(i) All design documentation specified in § 250.131(b) of this part, and

(ii) Abstracts of the computer programs used in the design process.

(3) *Fabrication verification plan requirements.* The fabrication plan shall also include fabrication drawings and material specifications for artificial island structures, major members of concrete- and steel-gravity structures, all the primary load-bearing members included in the space-frame analysis for jacket structures, and a summary description of the following:

(i) Structural tolerances,

(ii) Welding procedures,

(iii) Material (concrete, gravel, or silt) placement methods,

(iv) Fabrication standards,

(v) Material quality-control procedures,

(vi) Methods and extent of nondestructive examinations (NDE) for welds and materials, and

(vii) Quality assurance procedures.

(4) *Installation verification plan requirements.* Additionally, the installation plan shall include a summary description of the planned marine operations, contingencies considered, alternate courses of action, and the inspections to be performed including a graphical identification of areas to be inspected and the acceptance/rejection criteria.

(c) *Requirements for resubmittal.* All such plans or the appropriate part affected shall be resubmitted for approval if the CVA is changed, if the CVA's or assigned personnel's qualifications change, or if the level of work to be performed changes. The summary of technical details need not be resubmitted, unless changes are made in the technical details.

(d) *Combining of plans.* For manmade islands or platforms fabricated and installed in place, the fabrication and installation verification plans shall be combined.

§ 250.133 Certified Verification Agent duties and nomination.

(a) *CVA duties.* The CVA nominated by the lessee and approved by the Regional Supervisor shall conduct the appropriate reviews in accordance with the following:

(1) *Design phase.* (i) The CVA shall conduct the design verification to ensure that the proposed platform or major modification has been designed to withstand the maximum environmental and functional load conditions anticipated during the intended service life at the proposed location.

(ii) The design verification shall be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer.

(iii) The CVA shall consider the applicable provisions of §§ 250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of all proposed planning criteria, environmental data, load determinations, stress analyses, material designations, soil and foundation conditions, safety factors, and other pertinent parameters of the proposed design.

(iv) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(v) Upon completion of the design verification, a final report shall be prepared which summarizes the material reviewed by the CVA and the findings and includes a recommendation that the Regional Supervisor either accept, request modification(s), or reject the proposed design. In addition, the report shall include the particulars of how, by whom, and when the independent review was conducted and any special comments considered necessary. The final report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor within 6 weeks of the receipt of the design data or from the date the approval to act as a CVA was issued, whichever is later.

(2) *Fabrication verification.* The CVA shall monitor the fabrication of the platform or major modification to ensure that it has been built in accordance with the approved design plans and specifications and the fabrication plan, including the following:

(i) Periodic onsite inspections shall be made while fabrication is in progress. The following of the fabrication items, as appropriate, shall be verified:

(A) Quality control by lessee and builder,

(B) Fabrication site facilities,

(C) Material quality and identification methods,

(D) Fabrication procedures specified in the approved plan and adherence to such procedures,

(E) Welder and welding procedure qualification and identification,

(F) Structural tolerances specified and adherence to those tolerances,

(G) The NDE requirements and evaluation results of the specified examinations,

(H) Destructive testing requirements and results,

(I) Repair procedures,

(J) Installation of corrosion-protection systems and splash-zone protection,

(K) Erection procedures to ensure that overstressing of structural members does not occur,

(L) Alignment procedures,

(M) Dimensional check of the overall structure, and

(N) Status of quality-control records at various stages of fabrication.

(ii) The CVA shall consider the applicable provisions of §§ 250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of the fabrication of the platform or major modification.

(iii) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(iv) If the CVA finds that fabrication procedures are changed or design specifications are modified, the lessee shall be informed. If the lessee prefers to accept the modifications as informed by the CVA, the Regional Supervisor shall also be informed.

(v) A final report shall be prepared by the CVA covering the adequacy of the entire fabrication phase giving details of how, by whom, and when the independent monitoring activities were conducted and providing any special comments considered necessary. The final report is not required to cover aspects of the fabrication already included in interim reports. The final report shall describe the CVA's activities during the verification process, summarize the findings, contain a confirmation or denial of compliance with the design specifications and the approved fabrication plan, and a recommendation to accept or reject the fabrication. The report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor immediately after completion of the fabrication of the platform.

(3) *Installation phase.* The CVA shall witness the loadout of the jacket, deck(s), and piles from the fabrication site(s); review the towing records; conduct an onsite survey after transportation to the approved location; witness the actual installation of the platform or major modification; determine that the platform has been installed at the approved location in accordance with the approved design and the installation plan; and shall comply with the following:

(i) The CVA shall consider the applicable provisions of §§ 250.134 through 250.141 of this part and use good engineering practice in conducting an independent assessment of the adequacy of the installation activities. The following parts of the overall installation process, as appropriate, shall be verified:

(A) Loadout and initial flotation operations, if any;

(B) Towing operations to the specified location;

(C) Launching and uprighting operations;

(D) Submergence operations;

(E) Pile installation; and

(F) Final deck and/or component installation.

(ii) The CVA shall observe the installation activities, spot-check equipment, procedures, and recordkeeping, as necessary, to determine compliance with §§ 250.134 through 250.141 of this part and the approved plans, and immediately report to the Regional Supervisor and the lessee any discrepancies or damage to structural members. Approval for modified installation procedures or for major deviation from approved installation procedures shall be obtained from the Regional Supervisor.

(iii) Interim reports shall be submitted by the CVA, as appropriate, to the Regional Supervisor and the lessee.

(iv) A final report shall be prepared by the CVA covering the adequacy of the entire installation phase giving details of how, by whom, and when the independent monitoring activities were conducted and providing any special comments considered necessary. The final report shall describe the CVA's activities during the verification process, summarize the findings, contain a confirmation or denial of compliance with the approved installation plan, and a recommendation to accept or reject the installation. The report shall be submitted to the lessee and, in triplicate, to the Regional Supervisor within 2 weeks of completion of the installation of the platform.

(4) All data provided to the CVA shall be handled in the strictest confidence and not be released by the CVA without the consent of the lessee.

(5) Individuals or organizations acting as CVA's for a particular platform shall not function in any capacity other than that of a CVA for that specific project, whenever the additional activities would create a conflict, or appearance of a conflict of interest.

(b) *CVA nomination*—(1) *Nomination.* Individuals or organizations shall be nominated by the lessee planning to use their services. The lessee shall specify whether the nomination is for the design, fabrication, or installation phase of verification; for two phases; or for all three phases.

(2) *Qualifications.* Qualification submissions shall contain sufficient information to determine compliance with § 250.132(b)(1)(ii) of this part.

§ 250.134 Environmental conditions.

(a) *General.* The performance standards of this section pertain to all platforms covered by these requirements regardless of the fabrication material.

(1) *Environmental considerations.* All environmental phenomena appropriate to the areas of fabrication, transportation, and installation of an offshore platform shall be considered and their influence on the platform accounted for. Such phenomena shall include wind, waves, current, temperature, tide, marine growth, chemical components of air and water, snow and ice, earthquakes, tsunami, seiche, and other appropriate phenomena.

(2) *Environmental data.* Statistical data and defensible statistical and mathematical models shall be employed to describe the range of pertinent expected variations of environmental phenomena. Defensible data supplied by meteorologists, oceanographers, or other appropriate specialists are acceptable as the basis for design. Where possible, environmental phenomena shall be described by the characteristic parameters most relevant in the evaluation of effects on the platform.

(b) *Statistical methods.* (1) When statistical methods are employed in the determination of parameters characterizing environmental phenomena, the statistical methods and distributions employed shall be appropriate to their application as evidenced by relevant statistical tests, confidence limits, and other measures of statistical significance.

(2) Short-term and long-term variations of environmental phenomena such as wind, waves, and current shall be described by statistical distributions relevant to the parameter considered. Defensible statistical modeling techniques shall be used in the prediction of extreme values.

(3) When hindcasting techniques are employed to approximate environmental parameters, the validity of the model used shall be defensible.

(c) *Design considerations*— (1) *General.* A thorough assessment of the environment in the vicinity of the installation site shall be made to determine the conditions expected to occur at the site over the life of the platform.

(2) *Design environmental condition.* (i) "Design environmental condition" means the environmental factors producing the most unfavorable effects on the platform. Parameters describing the design environmental condition are given in paragraphs (c)(2)(ii)(A), (B), and (C) of this section.

(ii) The design environmental condition shall reflect the various environmental events that individually or collectively represent the most severe conditions the platform is anticipated to experience. Such conditions shall be formulated with a set of parameters that describe the relevant environmental events, including the following:

(A) The maximum wave corresponding to a selected recurrence period together with the associated wind, current, and appropriate ice and snow effects;

(B) The minimum air and sea temperatures appropriate to the event being treated; and

(C) The maximum water level due to tide and storm surge.

(iii) Consideration shall be given to other combinations of the parameters specified in paragraph (c)(2)(ii)(A) of this section involving either maximum wind, maximum current, or maximum ice load which may cause a greater response of the platform.

(iv) In general, the recurrence period chosen for the events specified in paragraphs (c)(2)(ii)(A) and (C) of this section shall primarily be based on the design service life of the platform. For platforms designed for a service life of 20 years, the recurrence period chosen for the determination of these events shall not be less than 100 years. For other service lives, the design event recurrence interval shall generally be adjusted to provide for a risk of occurrence which does not exceed the risk of occurrence for the 20-year/100-year combination.

(v) For installation sites located in seismically active areas, see paragraph (d)(8) of this section.

(3) *Operating environmental conditions.* Operating environmental

conditions means the set of characteristic parameters of environmental conditions associated with a normal function or operation to be conducted on the platform. For each such intended normal function or operation, the lessee shall determine a set of characteristic parameters of environmental conditions.

(d) *Specific environmental conditions.* (1) Waves information including the following: (i) Wave conditions considered for design shall be described by defensible statistical and/or deterministic methods.

(ii) Parameters characterizing design environmental waves shall be based on wave statistics or the results of defensible analytic prediction methods such as hindcasting techniques.

(iii) When using probabilistic analyses, the probability of occurrence of various wave-height groups classified by directionality and for a wide range of possible periods (i.e., tables of exceedance) shall be determined. Where required by the method selected to predict extreme values, the average duration of various wave-height groups (i.e., persistence data) shall be determined. All extrapolations and long-term wave data analyses shall use defensible techniques, and available data on extreme values measured in the vicinity of the site shall be included in the long-term prediction.

(iv) When using deterministic methods, waves shall be described by the parameters, height, period, and other relevant shape characteristics. The design-wave formulation used shall be valid for the problem considered.

(v) Breaking-wave criteria appropriate to the installation site shall be determined using defensible formulations.

(vi) If spectral wave data are established for the dynamic analysis of structural response to waves, such data shall be derived in accordance with defensible methods. If spectral data are not available in adequate quantities for the intended application, defensible mathematical formulations that best fit the available data shall be used.

(2) Wind information including the following:

(i) Wind velocities shall be classified on the basis of their duration. Wind velocities having a duration of less than 1 minute are referred to as gust winds. Wind velocities having a duration equal to or greater than 1 minute are referred to as sustained winds. The reference elevation is 33 feet above still-water level.

(ii) Wind conditions considered for design shall be described by defensible statistical or deterministic methods.

(iii) Wind profiles shall be determined on the basis of defensible statistical or mathematical models. Corrections of wind velocity data to averaging periods other than those employed in the collections of data shall be based on defensible methods.

(iv) Distribution of the direction and speed of wind approach to the platform shall be determined, or alternatively, winds shall be considered to approach from any direction.

(3) Current information including the following:

(i) Current velocities to be used in design shall be determined on the basis of the best statistics available. Tidal current, wind-generated current, density current, circulation current, and river-outflow current shall be combined on the basis of their probability of simultaneous occurrence in arriving at current velocities to be used in design.

(ii) Current velocity profiles shall be determined on the basis of site-specific studies or defensible empirical relationships. Unusual profiles due to bottom currents and stratified effects in regions near the mouth of large rivers shall be accounted for.

(iii) Directional data on currents which exist in the absence of waves shall be described for each month or by season. Unless a detailed study of current directions is made, currents shall be assumed to run in any direction.

(4) Tide information including the following:

(i) The design storm-tide elevation shall be identified for the installation site. For design purposes, the design environmental wave height shall be superimposed on the storm-tide elevation.

(ii) Variations in the elevation of the daily lunar tide shall be used in determining the elevations of boat landings, barge fenders, and the corrosion-prevention treatment of platforms in the splash zone (see § 250.138(c)(5) of this part).

(iii) The assumed maximum or storm tide shall include astronomical tide, wind tide, and pressure-induced storm surge. Minimum-tide estimates shall be based on either the astronomical or lunar tide only. The water depth shall be referenced to a datum (e.g., mean low/water or mean low low/water) consistent with all other references to elevations and depths.

(iv) If data directly applicable to the installation site are not available, the best estimate based on data for nearby locations shall be used.

(5) Temperature information including the following:

(i) Extreme values of low temperatures shall be expressed in terms of the most probable, lowest values with their corresponding recurrence periods;

(ii) Air, sea surface, and seabed temperatures shall be accounted for in describing the environment and in justifying the temperatures used in design.

(6) Snow and ice information including the following:

(i) If the platform is to be located in an area where sea ice may develop or drift, ice conditions shall be accounted for. Data shall be derived from actual field investigations, laboratory analyses, or other appropriate analogous sources;

(ii)(A) Relevant statistical and physical data on the sea-ice and snow conditions shall be described with particular attention to the following:

(*1*) Concentration and distribution of ice and snow,

(*2*) Morphology of sea ice (e.g., ice floes, ice ridges, or rafted ice),

(*3*) Mechanical properties of ice (mode of failure),

(*4*) Drift speed and direction,

(*5*) Thickness of ice and keel depth of pressure ridges, and

(*6*) Probability of encountering icebergs, ice floes, ice-floe fragments, and hummocks.

(B) The weight of the maximum snow and ice anticipated to accumulate on the platform shall be determined.

(7) Marine growth information including the following:

(i) When assessing the potential for marine growth, account shall be taken of relevant observations and experience in the area. In the absence of such information, defensible analytical techniques shall be employed to assess the potential for marine growth. These techniques shall take into account salinity, oxygen content, hydrogen-ion concentration value, current, temperature, water turbidity, and other appropriate factors.

(ii) Consideration shall be given to the selection of surface coatings which resist breakdown by micro-organisms which reduce the onset of corrosion.

(iii) Particular attention shall be paid to the effects that marine growth has on surface roughness characteristics of submerged structural members.

(8) Earthquake information including the following:

(i) The effects of earthquakes on platforms located in areas known to be seismically active shall be addressed.

(ii) Except for the provision of § 250.135(d)(5)(ii) of this part, the seismicity of the site shall be determined. Preferably, this shall be based on site-specific data. However, regional data shall be deemed

acceptable for use when site-specific data are not available and the regional data are interpreted in a manner to produce the most adverse effect on a platform at the specific site. The following data shall be obtained:

(A) Recurrence interval of seismic events appropriate to the design life of the structure,

(B) Proximity to active faults,

(C) Type of faulting,

(D) Attenuation of ground motion between the faults and the site,

(E) Subsurface soil conditions, and

(F) Records from past seismic events at the site or from analogous sites.

(iii) The use of available data to describe the seismic characteristics of the site is permitted where it can be shown that such data are consistent with the requirements of paragraph (d)(8)(ii) of this section.

(iv) The seismic data shall be used to establish a quantitative design earthquake criterion describing the design earthquake-induced ground motion. In addition to ground motion and as applicable to the installation site, the following earthquake-related phenomena shall be taken into account:

(A) Liquefaction of subsurface soils,

(B) Submarine slides,

(C) Tsunamis, and

(D) Fluid motions in tanks.

§ 250.135 Loads.

(a) *Introduction.* This section covers the identification, definition, and determination of the loads to which a fixed offshore platform may be exposed during and after its transportation and installation. The requirements contained in paragraphs (b) through (d) of this section apply to both steel-piled platforms and concrete-gravity platforms. Additional requirements covering steel-piled platforms are contained in paragraph (e) of this section. Additional requirements covering concrete-gravity platforms are contained in paragraph (f) of this section.

(b) *General.* (1) All types of loads specified in paragraphs (c)(1) through (c)(5) of this section shall be accounted for in the design and operation of the platform.

(2) Where applicable, the effects of increased dimensions and weight due to marine growth and snow and ice accumulation shall be addressed in the design.

(c) *Load definition*—(1) *Dead loads.* Dead loads associated with the platform are loads that do not change during the mode of operation under consideration. Dead loads include the following:

(i) Weight in the air of the platform (refer to paragraphs (e)(1) and (f)(1) of this section for itemizations of weight for pilefounded platforms and gravity platforms, respectively).

(ii) Weight of permanent ballast and the weight of permanent machinery including liquids at operating levels.

(iii) External hydrostatic pressure and buoyancy in calm sea conditions calculated on the basis of the design waterline.

(iv) Static earth pressure.

(2) *Live loads.* Live loads associated with the normal operation and use of the platform are loads that could change during the mode of operation considered. Live loads acting after fabrication or installation include the following:

(i) Weight of drilling and production equipment that can be removed such as derrick, draw works, mud pumps, mud tanks, separators, and tanks,

(ii) Weight of crew and consumable supplies such as mud, chemicals, water, fuel, pipe, cable, stores, drill stem, and casing.

(iii) Weight of liquids in storage tanks.

(iv) Forces exerted on the platform due to drilling, e.g., the maximum derrick reaction when placing or pulling casing.

(v) The forces exerted on the platform during the operation of cranes and vehicles.

(vi) The forces exerted on the platform by vessels moored to the platform.

(vii) The forces exerted on the platform by helicopters during takeoff and landing or while parked on the platform. When applicable, the dynamic effects on the platform of the forces specified in paragraphs (c)(2)(iv) through (vii) of this section shall be taken into account. Live loads occurring during transportation and installation shall be determined for each specific operation involved, and the dynamic effects of such loads shall be addressed (see § 250.140 of this part).

(3) *Deformation loads.* Deformation loads are loads due to deformations imposed on the platform. For an itemization of deformation loads applicable to steel-piled platforms and concretegravity platforms, see paragraphs (e)(2) and (f)(2) of this section, respectively.

(4) *Accidental loads.* Consideration shall be given to accidental loadings; and where such loadings are determined to be a factor, they shall be quantified and incorporated into the design. Accidental loads are loads that could occur as the result of an accident or exceptional conditions, such as the following:

(i) Extreme impact loads caused by supply boats, barges, and other craft anticipated to work in the vicinity of the platform;

(ii) Impact loads caused by dropped objects, such as drill collars, casing, blowout-preventer stacks;

(iii) Loss of internal pressure required to resist hydrostatic loading and to maintain buoyancy during the installation of the platform;

(iv) Explosion;

(v) Effects of fire; and

(vi) Iceberg collision.

(5) Environmental load information including the following:

(i) Environmental loads are loads due to wind, waves, current, ice, snow, earthquake, and other environmental phenomena.

(ii) The characteristic parameters defining an environmental load shall be appropriate to the installation site as determined by the studies required by § 250.134 of this part. Operating environmental loads are loads derived from the parameters characterizing operating environmental conditions (see § 250.134(c)(3) of this part). Design environmental loads are loads derived from the parameters characterizing the design environmental condition (see § 250.134(c)(2) of this part).

(iii) Environmental loads shall be applied to the platform from directions producing the most unfavorable effects on the platform unless site-specific studies allow for a less stringent requirement.

(iv) The combination and severity of design environmental loads shall be consistent with the likelihood of their simultaneous occurrence. The simultaneous occurrence of environmental loads shall be modeled by appropriate superposition methods.

(v) Earthquake loads and loads resulting from accidental or rare environmental phenomena need not be combined with other environmental loads unless site-specific conditions indicate that such combination is appropriate.

(d) *Determination of environmental loads.* (1) Wave load information including the following:

(i) Wave-induced loads shall be calculated using defensible methods or shall be obtained from adequate model or field test data;

(ii) A sufficient range of waves and wavecrest positions relative to the platform shall be investigated to ensure an accurate determination of the maximum wave load on the platform;

(iii) Wave impact loads on structural members below the design wave crest elevation shall be accounted for by defensible theoretical methods or relevant model test of full-scale data;

(iv) Where applicable, the possibility of dynamic excitation of the platform due to flow-induced cyclic loading shall be addressed;

(v) For additional requirements pertaining to steel-piled platforms and concrete gravity-platforms, see paragraphs (e)(3) and (f)(3) of this section, respectively; and

(vi) Where applicable, additional hydrostatic loading effects shall be addressed.

(2) Wind load information including the following:

(i) Wind loads, local wind pressures, and wind profiles shall be determined on the basis of defensible analytical methods or wind tunnel tests on a representative model of the platform.

(ii) In determining design environmental loads on the overall platform, wind loads calculated on the basis of the design-sustained wind velocity shall be combined with other design environmental loads.

(iii) The design gust wind load shall be used in the design of local structure unless the effects of the load combination described in paragraph (d)(2)(ii) of this section are more severe.

(iv) Where appropriate, the dynamic effects due to the cyclic nature of gust wind and cyclic loads due to vortex shedding shall be computed by defensible methods before computing the total force, and

(v) Where appropriate, flutter and load amplification due to vortex shedding shall be addressed.

(3) Ice and snow load information including the following:

(i) For platforms located in areas associated with ice movement, contact loads caused by floating ice shall be determined according to defensible theoretical methods, model test data, or full-scale measurements;

(ii) In locations where platforms are subject to ice and snow accumulation, the additional weight of snow and ice on the platform shall be addressed;

(iii) The effects of ice accumulation and ice jam, including the effects of changes in configuration due to adhesion, shall be accounted for in the determination of the total environmental load; and

(iv) The incident pressure due to pack ice, pressure ridges, and where appropriate, ice island fragments impinging on the platform shall be addressed.

(4) Earthquake load information including the following:

(i) For platforms located in seismically active areas, design earthquake-induced ground motions shall be determined on the basis of seismic data applicable to the installation site. Design earthquake ground motions shall be described by either applicable ground motion records or response spectra consistent with the recurrence period appropriate to the design life of the platform.

(ii) Available and defensible standardized spectra applicable to the region of the installation site are acceptable if such spectra reflect those site-specific conditions affecting frequency content and energy distribution. These conditions include the type of active faults in the region, the proximity of the site to the potential source faults, the attenuation or amplification of ground motion between the faults and the site, and the soil conditions at the site.

(iii) Ground-motion descriptions shall consist of three components corresponding to two orthogonal horizontal directions and the vertical direction. All three components shall be applied to the platform simultaneously.

(iv)(A) When the response spectrum method is used for structural analysis, input values of ground motion (spectral acceleration representation) shall not be less severe than the following:

(*1*) One hundred percent in a principal horizontal direction,

(*2*) Sixty-seven percent in the orthogonal horizontal direction, and

(*3*) Fifty percent in the vertical direction.

(B) The horizontal components shall also be applied in the alternative orthogonal horizontal directions.

(v) If the time history method is used for structural analysis, at least three sets of ground-motion time histories shall be employed. The manner in which the time histories are used shall account for the potential sensitivity of the platform's response to variations in the phasing of the ground-motion records.

(vi) When applicable, effects of soil liquefaction and/or loads resulting from submarine slides or creep, tsunamis, and earthquake motions shall be addressed.

(e) *Loads on steel pile-supported platforms.* The following requirements apply to loads on steel pile-supported platforms and shall be applied together with the requirements in paragraphs (b), (c), and (d) of this section:

(1) The dead load of the platform shall include, as appropriate, the weight in air of the jacket, piling, grout, superstructure modules, stiffeners, decking, piping, heliport, and any other fixed structural part less buoyancy, with due allowance for flooding.

(2) Where appropriate, the deformation loads to be accounted for are those resulting from temperature variations leading to thermal stresses in the platform, and those resulting from soil displacements (e.g., differential settlements or lateral displacements).

(3) Wave load information including the following:

(i) For platforms composed of members having diameters that are negligible in relation to the wave lengths considered, semiempirical formulations accounting for wave-induced drag and inertia forces based on the water particle velocities and accelerations on an undisturbed, incident flow field are acceptable;

(ii) When a method as described in paragraph (e)(3)(i) of this section is used, the wave field shall be described by a defensible wave theory appropriate to the wave heights, wave periods, and water depth at the installation site;

(iii) The coefficients of drag and inertia used in calculating wave loads shall be determined on the basis of model test results, published data, or full-scale measurements appropriate to the structural configuration, surface roughness, and wave field; and

(iv) For platforms composed of members whose diameters are not negligible in relation to the wave lengths considered and for structural configurations that will substantially alter the undisturbed, incident flow field, diffraction forces and the hydrodynamic interaction of structural members shall be taken into account.

(f) *Loads on concrete-gravity platforms.* The following requirements apply to loads on concrete-gravity platforms and shall be applied together with the requirements described in paragraphs (b), (c), and (d) of this section.

(1) The dead load of the platform shall include, as appropriate, the weight in air of the foundation, skirts, columns, superstructure modules, decking, piping, heliport, and any other fixed structural part less buoyancy with due allowance for flooding. Weight calculations based on nominal dimensions and mean values of density are acceptable.

(2) The deformation loads to be accounted for are those due to prestress, shrinkage and expansion, creep, temperature variations, and differential settlements.

(3) Wave load information including the following:

(i) For platforms composed of large gravity bases and one or more columns whose diameters are not negligible in relation to the wave lengths considered, defensible wave-load theories which account for the drag, inertia, and diffraction forces on the platform shall be employed;

(ii) For complex structural configurations, the hydrodynamic

interaction of large, immersed structural members shall be addressed;

(iii) When diffraction forces and hydrodynamic interaction are negligible, only semiempirical formulations comparable to those mentioned in paragraphs (e)(3)(i) and (iii) of this section accounting for drag and inertia forces are acceptable; and

(iv) The undisturbed, incident flow field shall be addressed by a defensible wave theory appropriate to the wave heights, wave periods, and water depth at the installation site.

§ 250.136 General design requirements.

(a) *General.* This section specifies the general concepts and methods of analysis to be incorporated in the design of a platform.

(b) *Analytical approaches.* (1) Structural response information including the following:

(i) Methods of analysis employed in association with the specifications of these requirements shall treat geometric and material nonlinearities in a defensible manner. When nonlinear methods of analysis are used to assess collapse mechanisms, it shall be demonstrated that the platform has sufficient ductility to develop the required resistance or structural displacements.

(ii) Where theoretically based analytical procedures covering the platform or parts thereof are unavailable or not well defined, model studies shall be utilized. The acceptability of model studies depends on the procedures employed, including enumeration of the possible sources of errors, the limits of applicability of the model test results, and the methods of extrapolation to full-scale data.

(2) Loading format information including the following:

(i) Either a deterministic or spectral format shall be employed to describe various load components. When a static approach is used, it shall be demonstrated, where appropriate, that the general effects of dynamic amplification were addressed. The influence of waves other than the highest waves shall be investigated for their potential to produce maximum peak stresses resulting from possible resonance with the platform.

(ii) When considering the design earthquake as discussed in § 250.135 of this part, a dynamic analysis shall be performed. A dynamic analysis shall also be performed to assess the effects of environmental or other types of loads if significant dynamic amplification is expected.

(iii) For fatigue analysis, the long-term distribution of the stress range, with proper consideration of dynamic effects, shall be obtained for relevant loadings anticipated during the design life of the platform (see §§ 250.137(c)(6) and 250.138(c)(6) of this part).

(3) Combinations of loading components information including the following:

(i) Loads imposed during and after installation shall be taken into account. Of the various loads described in § 250.134, of this part, those loads to be considered for design shall be combined in a manner consistent with their probability of simultaneous occurrence. However, earthquake loadings shall be applied without consideration of other environmental effects unless conditions at the site necessitate their inclusion. The direction of applied environmental loads shall be that producing the highest possible influences on the platform, considering the platform's orientation and location with respect to bottom topography, direction of fetch, and nearby land masses.

(ii) While it is required to obtain and use those loading components which produce realistic maximum effects on the platform, loading combinations corresponding to conditions after installation shall reflect both operating and design environmental loadings. Sections 250.137, 250.138, and 250.139 of this part give the minimum load combinations to be considered.

(iii) The operating environmental conditions and the maximum tolerable environmental loads during installation shall be specified.

(c) *Overall design considerations*—(1) *Design life.* The design service life of the platform shall be specified as prescribed in § 250.134(c)(2)(iv) of this part.

(2) *Air gap.* An air gap of 5 feet shall be provided between the maximum crest elevation of the design wave (including tidal effects) and the lowest portion of the platform upon which wave forces have not been included in the design. After accounting for the initial and long-term settlements resulting from consolidation and subsidence, the elevation of the crest of the design wave shall be based on the elevation of the mean low-water line, astronomical and storm tides, wave runup, the tilting of the platform, and where necessary, tsunamis.

(3) *Long-term and secondary effects.* The following effects shall be addressed, as appropriate, for the planned platform:

(i) Local vibration due to machinery, equipment, and vortex shedding;

(ii) Stress concentrations at critical joints;

(iii) Secondary stresses induced by large deflections (P-Δ effects);

(iv) Cumulative fatigue;

(v) Corrosion;

(vi) Marine growth; and

(vii) Ice abrasion.

(4) *General arrangement.* The platform and equipment shall be arranged to minimize the potential of structural damage and personal injury resulting from accidents. In this regard, the consequences of the arrangement or placement of the following components and their effects shall be addressed:

(i) Equipment and machinery—noise and vibration,

(ii) High-pressure piping—leakage in closed spaces,

(iii) Lifting devices—dropped loads, and

(iv) Vessel mooring devices—line breakage and tripping quick-release mechanisms.

(5) *Corrosion-protection zones.* Measures taken to mitigate the effects of corrosion as required by §§ 250.137(d) and 250.138(c)(5) of this part shall be specified and described in terms of the following definitions for corrosion-protection zones:

(i) Submerged zone—that part of the platform below the splash zone,

(ii) Splash zone—that part of the platform between the highest and lowest water levels reached by sea states exceeded for 1 percent of the time annually when superimposed on the highest and lowest levels of tide with due allowance for high and low installation of the platform,

(iii) Atmospheric zone—that part of the platform above the splash zone,

(iv) Ice zone—that part of the platform which can reasonably be expected to come into contact with floating or submerged ice annually.

§ 250.137 Steel platforms.

(a) *Materials*—(1) *General.* (i) This section covers specifications for materials used for the construction of steel pile-supported platforms. Steels shall be suitable for their intended service as demonstrated by testing under relevant service conditions or previous satisfactory performance under service conditions similar to those intended. Steels shall be of good commercial quality, defined by specification, and free of injurious defects.

(ii) Steels shall exhibit satisfactory formability and weldability characteristics and fracture toughness satisfactory for the intended applications. Materials for structural members which are fracture critical or for members which sustain significant tensile stress and whose fracture would pose a threat to the survival of the

platform shall have sufficient toughness to guard against brittle fracture. Materials selected for members which are subjected to significant tensile stress shall have toughness suitable to their intended application.

(iii) In cases where principal loads from either service or weld residual stresses are imposed normal to the plate, appropriate precautions shall be taken to avoid lamellar tearing parallel to the plate surface.

(2) Material selection information including the following:

(i) Steels for structural members shall be selected according to criteria that take into account the required yield strength, fracture toughness, service temperature (see paragraph (a)(3) of this section), and intended application;

(ii) Bolts and nuts shall have mechanical and corrosion properties comparable to the structural elements being joined. Materials for bolts and nuts shall be defined by and tested in accordance with material standards compatible with those for the joined structural members;

(iii) When new alloys are used, the adequacy of fracture toughness shall be supported by appropriate fracture tests; and

(iv) When materials other than steel are used for structural purposes, the mechanical and durability properties necessary for their intended function shall be designated, including toughness and fatigue characteristics, where necessary.

(3) *Service temperature.* Service temperature means the temperature that the material is expected to achieve in the operational environment.

(i) For material at or below the waterline, the minimum service temperature shall be the lowest average daily water temperature applicable to the particular depth. For material above the waterline, the minimum service temperature shall be the lowest 1-day average daily atmospheric temperature over a 10-year period, unless the material is warmed by auxiliary heating.

(ii) In all cases where material temperature is reduced by localized cryogenic storage or other cooling means, such factors shall be accounted for in establishing minimum service temperature.

(4) *Classification of applications.* When considering the welding requirements given in subsequent sections, materials shall be considered as "Weld Class A" if the members are critical or special structural elements, "Weld Class B" if the members are primary load-carrying members of the platform, or "Weld Class C" if the members are secondary structural elements.

(5) *Material designation.* All material employed in platform construction shall be described and designated by a material specification.

(b) *Fabrication and welding*—(1) *General.* (i) Welding shall be performed in accordance with the applicable provisions of the American Welding Society (AWS) publication, AWS D1.1, Structural Welding Code—Steel, or other appropriate welding codes.

(ii) Fabrication other than welding shall be performed in accordance with the American Institute of Steel Construction (AISC) publication, S326, Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, or other appropriate codes. The code to be followed during fabrication and construction shall be specified on design documents.

(2) *Welding.* (i) Welding procedures and filler metals shall be selected to produce sound welds, and the filler metal shall have strength and toughness compatible with the base metal. Workmanship shall be in compliance with paragraph (b)(1)(i) of this section.

(ii) Forming processes shall not degrade the base metals below their minimum required properties. A heat treatment shall be employed to provide the required properties, where necessary.

(iii) Misalignment between parallel (abutting) members shall be minimized. Weld size for fillet welds shall be sufficient to compensate for the gap between faying surfaces of the members. Lapped joints shall possess sufficient overlaps. Both edges of an overlap joint shall have continuous fillet welds.

(iv) When arc-air gouging is employed, the carbon buildup and burning of the weld or base metals shall be minimized.

(v) Peening shall not be used for single-pass welds or for the root or cover passes of multipass welds. Peening shall be used only after cleaning of weld passes. Fairing by heating, flame shrinking, or other methods, when applied to Weld Class A or B structural elements, shall be performed without damaging the base metals. Such corrective measures shall be kept to a minimum when treating high-strength steels.

(3) *Quality assurance.* A documented inspection plan shall be prepared and followed and shall cover the following items:

(i) A suitable system for material identification and quality control during all stages of construction,

(ii) Requirements for welding procedures and welder qualifications,

(iii) The extent of weld inspection (including nondestructive examination methods) and the criteria for weld acceptance or rejection, and

(iv) Necessary dimensional tolerances.

(4) *Weld nondestructive examination.* (i) All welds shall be subjected to visual examination. Nondestructive examination shall be conducted to the extent indicated in paragraph (b)(4)(ii) of this section after all forming and postweld heat treatments have been completed. Weld examination procedures shall be adequate to detect delayed weld cracking in cases involving high-strength steels or high-hydrogen welding processes.

(ii) As called for in paragraph (b)(3)(iii) of this section, a plan for nondestructive examination of the welds shall be prepared and followed. The extent of inspection of Weld Classes A and B structural elements shall be consistent with the applications involved. Important welds of Weld Classes A and B structural elements are those inaccessible or very difficult to inspect in service. Important welds shall be subjected to an increased level of nondestructive examination during fabrication.

(iii) If the proportion of unacceptable welds becomes excessive, the frequency of nondestructive examination shall be increased.

(c) *Design and analysis*—(1) *General.* (i) Steel platforms shall be adequately designed and analyzed to withstand the loads to which they are likely to be exposed during their design life. The effects on the platform shall be determined for a minimum set of loading conditions by using a defensible method to ensure that the resulting responses do not exceed the safety criteria appropriate to the methods employed.

(ii) The use of design methods, other than those specifically covered in this section, and their associated safety criteria are allowed if it can be demonstrated that such alternative methods will result in a structural safety level equivalent to that provided by the direct application of these requirements.

(iii) Sections 250.135 and 250.136 of this part shall be consulted regarding definitions and requirements pertinent to the determination of loads and general design requirements.

(2) *Loading conditions.* (i) Appropriate loading conditions that produce the most adverse effects on the platform during and after fabrication and installation shall be considered;

(ii) Loadings corresponding to conditions after installation shall include at least those relating to both

the operating and design environmental conditions, combined with other pertinent loads in the following manner:

(A) Operating environmental conditions combined with dead and live loads appropriate to the function and operation of the platform;

(B) Design environmental conditions combined with dead and live loads appropriate to the function and operation of the platform;

(C) Design environmental conditions combined with dead loads and minimum live loads appropriate to the function and operation of the platform; and

(iii) For platforms located in seismically active areas, loads induced by earthquake ground motions shall be combined with dead and live loads appropriate to the operation and function of the platform.

(3) *Methods of design and analysis.* (i) The nature of loads and loading combinations as well as the local environmental conditions shall be considered in the selection of design methods. Methods of analysis and their associated assumptions shall be compatible with the overall design principles.

(ii) Linear, elastic methods (working stress methods) of design and analysis are acceptable if proper measures are taken to prevent general and local buckling failure. Regarding structural instability as a possible mode of failure, the effects of initial stresses and geometric imperfection shall be taken into account.

(iii) Dynamic effects shall be accounted for if the wave energy in the frequency range of the structural resonance frequencies is of sufficient magnitude to produce significant stresses in the platform. The determination of dynamic effects shall be accomplished either by computing the dynamic amplification effects in conjunction with a deterministic analysis or by a random dynamic analysis based on a spectral formulation. In the latter case, the analysis shall be accompanied by a statistical description and evaluation of the relevant input parameters.

(iv) The interaction of the soil with the platform's piles shall be included in the analytical model used to obtain the structural response (see § 250.139(d)(1)(iv) of this part).

(v) For static loads, plastic methods of design and analysis shall be employed only when the properties of the steel and the connections exclude the possibility of brittle fracture and allow for formation of plastic hinges with sufficient plastic rotation capacity and adequate fatigue resistance.

(vi) Whenever plastic analysis is used, it shall be demonstrated that the collapse mode (mechanism) corresponding to the smallest loading intensities has been used for the determination of the ultimate strength of the platform. The effect of buckling and other destabilizing nonlinear effects shall be taken into account in the plastic analysis of platforms with compressive forces. Whenever nonmonotonic or repeating loads are present, it shall be demonstrated that the structure will not fail by incremental collapse or fatigue.

(vii) Under dynamic loads when plastic strains may occur, the considerations specified in paragraph (c)(3)(v) of this section shall be satisfied and any buckling and destabilizing nonlinear effects shall be taken into account.

(4) *Allowable stresses and load factors.* (i) When the design is based on a working-stress method (see paragraphs (c)(1)(ii) and (c)(3)(ii) of this section), the safety criteria shall be expressed in terms of appropriate basic allowable stresses in accordance with requirements specified in paragraphs (c)(4)(ii) through (vi) of this section.

(ii) For structural members and loadings covered by the AISC publication, S326, Part 1, with the exception of earthquake loadings (see paragraph (c)(4)(v) of this section) and tubular structural members under the combined loading of axial compression and bending, the basic allowable stresses of the members shall be obtained using the AISC specification. For tubular members subjected to the aforementioned interaction, stress limits shall be set in accordance with a defensible formulation.

(iii) Where stresses in members listed in paragraph (c)(4)(ii) of this section are shown to result from forces imposed by the design environmental conditions acting alone or in combination with dead and live loads (see paragraph (c)(2)(ii) of this section), the basic allowable stresses cited in paragraph (c)(4)(ii) of this section, modified by a factor of four-thirds, are permitted for the design environmental load contribution if the resulting structural member sizes are not less than those required for dead and live loads plus operating environmental conditions without the one-third increase in allowable stresses.

(iv) For any two- or three-dimensional stress fields within the scope of the working-stress formulation, the equivalent stress (e.g., the von Mises stress intensity) shall be limited by an appropriate allowable stress less than the yield stress, with the exception of stresses of a highly localized nature. In the latter case, local yielding of the structure is acceptable if it can be demonstrated that such yielding does not lead to progressive collapse of the overall platform and that the general structural stability can be maintained.

(v) When considering loading combinations on individual members or on the overall platform, which include loads defined as accidental (see § 250.135(c)(4) of this part), or in pursuing structural analysis for earthquake loads (see paragraph (c)(2)(iii) of this section), the allowable stress set at a level of the minimum yield or buckling strength of the material shall be considered appropriate.

(vi) Whenever elastic instability, overall or local, may occur before the compressive stresses reach the minimum specified yield strength of the material, appropriate allowable buckling stresses shall govern.

(vii) Whenever the ultimate strength of the platform is used as the basis for the design of its members, the safety factors or the factored loads shall be formulated in accordance with the requirements of AISC publication, S326, Part 2, or an equivalent code. The capability of the primary structural members to develop their predicted ultimate load capacity shall be demonstrated.

(viii) For details of high-stress concentration, consideration shall be given to safety against brittle fracture and to material quality-control procedures.

(5) *Structural response to earthquake loads.* (i) Platforms located in seismically active areas shall be designed to possess adequate strength and stiffness to withstand the effects of an earthquake which has a reasonable likelihood of not being exceeded during the lifetime of the structure (see paragraph (c)(2)(iii) of this section) and remain stable during rare motions of greater severity;

(ii) The adequacy of structural strength shall be demonstrated by analysis to verify that no significant structural damage occurs; and

(iii) Platforms shall also possess adequate ductility to withstand a rare intense earthquake.

(6) *Fatigue assessment.* (i) Structural members and joints for which fatigue is a probable mode of failure and for which past experiences are insufficient to ensure safety from possible cumulative fatigue damage shall be analyzed. Emphasis shall be given to joints and members in the splash zone, those that are difficult to inspect and repair after the platform is in service.

and those susceptible to corrosion-accelerated fatigue, and

(ii) For structural members and joints which require a detailed analysis of cumulative fatigue damage, the results of the analysis shall indicate a minimum calculated life of twice the design life (see § 250.136(c)(1) of this part) of the platform if there is sufficient structural redundancy to prevent catastrophic failure of the platform as a result of fatigue failure of the member or joint under consideration. If such redundancy does not exist or if the desirable degree of redundancy is significantly reduced as a result of fatigue damages, the results of a fatigue analysis shall indicate a minimum calculated life of three times the design life of the platform.

(d) *Corrosion protection.* All materials shall be protected from the effects of corrosion by a corrosion-protection system. The design of such systems shall take into account the possible existence of stress corrosion, corrosion fatigue, and galvanic corrosion. If the intended sea environment contains unusual contaminants, any special corrosive effects of such contaminants shall also be considered. Protection systems shall be designed in accordance with the National Association of Corrosion Engineers (NACE) publication, NACE Standard RP–01–76, Recommended Practice, Corrosion Control of Steel, Fixed Offshore Platforms Associated With Petroleum Production, or other comparable standards.

(e) *Connection of piles to structure.* The attachment of the jacket structure to the piles shall be accomplished by positive, controlled means. Such attachments shall be capable of withstanding the static and long-term cyclic loadings to which they will be subjected.

§ 250.138 Concrete-gravity platforms.

(a) *General.* (1) This section covers the materials, analysis, design, and construction of reinforced and/or prestressed concrete-gravity platforms.

(2) Materials, structural systems, methods of design, and methods of construction that do not conform to the requirements of this section shall not be used unless it is shown that they will result in a safety level at least equivalent to that provided by the direct application of the requirements of this section.

(b) *Materials*—(1) *General.* All materials shall be selected with due attention to their strength and durability in the marine environment. All material tests shall be performed in accordance with the latest, applicable standards of the American Society for Testing and Materials (ASTM).

(2) *Cement.* (i) Cement shall be equivalent to Type I, II, or III portland cement as specified by ASTM C150, Specification for Portland Cement, or portland-pozzolan cement as specified by ASTM C595, Specification for Blended Hydraulic Cements. However, the suitability of Type III cement to serve its intended function shall be demonstrated.

(ii) The tricalcium aluminate content of the cement shall be such as to enhance the corrosion protection of reinforcing steel without impairing the durability of concrete.

(iii) If oil storage is planned and the oil is expected to contain soluble sulfates in amounts that may impair the durability of concrete, the tricalcium content shall be reduced or a suitable coating employed to protect the concrete.

(3) *Water.* (i) Water used in mixing concrete shall be clean and free from injurious amounts of oils, acids, alkalis, salts, organic materials, or other substances that may be deleterious to concrete or steel.

(ii) If nonpotable water is used, the proportions of materials in the concrete shall be based on test concrete mixes using water from the same source. The strength of mortar test cubes made with nonpotable water shall not be significantly below the strength of similar cubes made with potable water.

(iii) Water for reinforced or prestressed concrete or grout shall not contain chlorides and sulfates in amounts detrimental to the durability of the platform.

(4) *Aggregates.* (i) Aggregates shall conform to the requirements of ASTM C33, Specifications for Concrete Aggregates. Lightweight aggregates conforming to ASTM C330, Specifications for Lightweight Aggregates for Structural Concretes, shall only be permitted if they do not pose durability problems and where they are used in accordance with the applicable provisions of the ACI publication, ACI 318–83, Building Code Requirements for Reinforced Concrete, plus Supplement and Commentary.

(ii) Marine aggregates shall be washed with fresh water before use to remove the surface and soluble chlorides and sulfates so that the total chloride and sulfate content of the concrete mix water does not exceed the limits of paragraph (b)(3)(iii) of this section.

(iii) The maximum size of the aggregate shall be such that the concrete can be placed without voids.

(5) *Admixtures.* The admixture shall be shown capable of maintaining essentially the same composition and performance throughout the work as the product used in establishing concrete proportions. Admixtures containing chloride ions shall not be used in prestressed concrete or in concrete containing aluminum embedments.

(6) *Reinforcing and prestressing systems.* (i) Reinforcing and prestressing systems shall conform to the requirements of ACI 318–83, and

(ii) Structural steel used in composite structures shall conform to the requirements of § 250.137 of this part.

(7) *Concrete.* The concrete shall be designed to ensure sufficient strength and durability. The quality control of concrete shall conform to ACI 318–83. The mixing, placing, and curing of concrete shall conform to the requirements of paragraph (e) of this section. The water-cement ratio shall be strictly controlled and in no case shall it exceed 0.45.

(8) *Grout for bonded tendons.* (i) Grout for bonded tendons shall conform to ACI 318–83, and

(ii) The maximum allowable contents of chlorides and sulfates determined in accordance with paragraph (b)(3)(iii) of this section shall also apply to grout mixes.

(9) *Post-tensioning ducts.* Post-tensioning ducts shall conform to the requirements of ACI 318–83. Ducts and duct splices shall be watertight and grout-tight and shall be of suitable thickness to prevent crushing, deformation, and blockage.

(10) *Post-tensioning anchorages and couplers.* Post-tensioning anchorages and couplers shall conform to the requirements of ACI 318–83.

(c) *Design requirements*—(1) *General.* (i) The strength of the platform shall be adequate to resist failure of the platform or its components. Among the modes of possible failure that shall be considered are the following:

(A) Loss of overall equilibrium,

(B) Failure of critical sections, and

(C) Instability (buckling).

(ii) Additionally, the following items shall be considered in relation to their potential influences on the platform:

(A) Cracking or spalling,

(B) Deformations,

(C) Corrosion of reinforcement or deterioration of concrete, and

(D) Vibrations.

(2) *Required strength.* The required strength shall conform to requirements of ACI 357R.

(3) *Design strength.* The design strength shall conform to requirements of ACI 318–83 and ACI 357R.

(4) *Other design requirements.* (i) In considering those items listed in

paragraph (c)(1)(ii) of this section, the ability of the platform to withstand unfactored loads in the following combination shall be demonstrated:

$D+T+L+E_o$

where L represents the most unfavorable live load; D, the dead load; T, the deformation load; and E_o, the operating environmental load, and

(ii) Crack control design shall be achieved by limiting the crack width in concrete subjected to tension or by limiting the tensile stress in reinforcing steel and prestressing tendons.

(5) *Durability.* (i) Materials, design, construction procedures, and quality control shall be such as to produce satisfactory durability of platforms in a marine environment, and

(ii) The following items shall be considered in the four zones of exposure (see § 250.136(c)(5) of this part):

(A) Submerged zone—chemical deterioration of the concrete, corrosion of the reinforcement and hardware, and abrasion of the concrete;

(B) Splash zone—freeze-thaw durability, corrosion of the reinforcement and hardware, the chemical deterioration of the concrete, and fire hazards;

(C) Atmospheric zone—freeze-thaw durability, corrosion of reinforcement and hardware, and fire hazards; and

(D) Ice zone—mechanical deterioration resulting from the abrasive action of moving ice.

(6) *Fatigue.* Platforms for which fatigue is a probable mode of failure shall be designed to limit the effects of cumulative material fatigue. The effects of fatigue induced by normal stress and those resulting from shear and bond stress shall be considered. Particular attention shall be given to submerged areas subjected to the low-cycle, high-stress components of the anticipated loading history. If an analysis of the fatigue life is performed in lieu of employing other methods to obviate the possibility of fatigue damage, the calculated fatigue life of the platform shall be at least twice the design life (see § 250.136(c)(1) of this part).

(d) *Analysis and design*—(1) *General.* (i) The analysis of platforms shall be pursued under the assumptions of linearly elastic materials and linearly elastic structural behavior, except as listed in paragraphs (d)(1) (ii) and (iii) of this section.

(ii) The inelastic behavior of concrete, based on the true variation of the modulus of elasticity with stress, shall be taken into account whenever its effect reduces the strength of the platform.

(iii) The geometric nonlinearities and the effect of initial deviation of the platform from the design geometry shall be taken into account whenever their effects reduce the strength of the platform.

(iv) Where appropriate, dynamic effects shall be taken into account. The dynamic response shall be determined by a defensible method that includes the effects of the foundation—platform interaction and the effective mass of the surrounding water.

(v) The material properties used in the analysis shall be based on actual laboratory tests or shall follow the appropriate sections of ACI 318–83.

(2) *Analysis of frames.* The analysis of frames shall be performed by a defensible method of structural mechanics. The buckling strength of the frame shall be assessed, and the safety against buckling failure shall be ensured to a degree consistent with the requirements in paragraphs (c)(2) and (c)(3) of this section.

(3) *Analysis of plates, shells, and folded plates.* The buckling strength of these plates shall be determined and a sufficient safety margin against instability shall be ensured.

(4) *Determination of deflections.* Deflections shall be determined by a defensible method. In addition to the immediate (instantaneous) deflections, the long-term deflections due to creep shall be accounted for.

(5) *Analysis and design for bending and axial loads.* The provisions of ACI 318–83 shall apply to the analysis and design of members subject to flexure or axial loads or to combined flexure and axial loads.

(6) *Analysis and design for shear and torsion.* The provisions of ACI 318–83 shall apply to the analysis and design of members subject to shear or torsion or to combined shear and torsion.

(7) *Analysis and design of prestressed concrete.* The analysis and design of prestressed concrete members and structures shall comply with ACI 318–83. In addition, the safety requirements of paragraph (c) of this section shall be satisfied.

(8) *Details of reinforcement and prestressing systems.* Details of reinforcement and prestressing systems shall conform to the requirements of ACI 318–83 with special attention given to the fatigue resistance and ultimate behavior of offshore structures.

(9) *Minimum reinforcement.* The minimum amount of reinforcement shall conform to the requirements of ACI 318–83. Additionally, sufficient reinforcement shall be provided to control crack growth, especially at surfaces exposed to severe hydraulic pressures.

(10) *Concrete cover of reinforcement and prestressing tendons.* The concrete cover of reinforcement and prestressing tendons shall be sufficient to provide for corrosion protection of the steel.

(11) *Seismic analysis.* A dynamic analysis shall be performed to determine the response of the platform to design-earthquake loading. The platform shall be designed to withstand this loading without damage. In addition, a ductility check shall also be performed to ensure that the platform has sufficient ductility to experience deflections more severe than those resulting from the design-earthquake loading without the collapse of the platform or its foundation or any primary structural component.

(12) *Seismic design.* The design of structural members and details of platforms subjected to seismic loading shall ensure maximum ductility at critically loaded sections.

(e) *Construction*—(1) *General.* (i) Construction methods and workmanship shall conform to the provisions of ACI 318–83 and to the following requirements.

(ii) At each stage of construction, i.e., fabrication, initial flotation, towing, and installation in situ, the forces acting on the platform shall be kept within the safety limits listed in paragraph (c) of this section. Appropriate static and/or dynamic analysis shall be performed for the operating loading conditions of each of the construction operations mentioned above. Buoyancy and stability shall be considered during all phases of construction.

(2) *Mixing, placing, and curing of concrete.* (i) Mixing of concrete shall conform to the requirements of ACI 318–83 and ASTM C94, Specification for Ready Mixed Concrete;

(ii) When concreting in cold weather, the temperature of the fresh concrete shall be maintained sufficiently above freezing until the process of hardening is well in progress;

(iii) In hot weather, the temperature of the fresh concrete shall be controlled so that it does not impair attainment of the desired strength and durability;

(iv) The methods for curing concrete shall ensure maximum compressive and tensile strength, durability, and a minimum of cracking; and

(v) The location and workmanship of construction joints shall not impair the strength, crack resistance, and watertightness of the platform.

(3) *Reinforcement.* (i) Reinforcement shall be free from loose rust, grease, oil, deposits of salt, or any other material

that may adversely affect the strength, durability, or bond of the reinforcement. The specified cover of reinforcement shall be maintained accurately. The cutting, bending, and fixing of reinforcement shall ensure that it is correctly positioned and rigidly held.

(ii) The welding of reinforcement shall conform to the requirements of AWS publication, AWS D1.4, Structural Welding Code— Reinforcing Steel.

(4) *Prestressing tendons, ducts, and grouting.* (i) Steps shall be taken to ensure that the achieved prestressing force is that specified in the design.

(ii) Tendons and ducts shall be in a condition that ensures the required strength, durability, and bond.

(iii) The grouting procedures shall produce the required bond strength of the tendons and provide permanent corrosion protection for the tendons. Anchorages shall also be protected adequately against corrosion.

§ 250.139 Foundation.

(a) *General*—(1) *Coverage.* Soil investigations, design considerations for the supporting soil, and the influence of the soil on the foundation structure are addressed in this section, including criteria for the strength and deformation characteristics of the foundation employed by both pile founded and gravity platforms.

(2) *Guidelines.* (i) The degree of design conservatism shall reflect prior experience under similar conditions, the manner and extent of data collection, the scatter of design data, and the consequences of failure;

(ii) For cases where the limits of applicability of any method of calculation employed are not well defined or where the soil characteristics are quite variable, the use of more than one method of calculation or a parametric study of the sensitivity of the important design variables shall be considered, and

(iii) A listing of design parameters, necessary calculations, and test results shall be retained by the designer.

(b) *Site investigation*—(1) *General* (i) The actual extent, depth, and degree of precision to be obtained in the site investigation program shall reflect the type and intended use of the platform, characteristics of the site, similarity of the area based on previous site studies or platform installations as well as the consequences of a failure of the foundation. The site investigation program shall generally consist of three major phases as follows:

(A) Shallow hazards (see paragraph (b)(2) of this section) to obtain relevant geophysical data.

(B) Geological survey (see paragraph (b)(3) of this section) to obtain data of a regional nature concerning the site.

(C) Subsurface investigation and testing (see paragraph (b)(4) of this section) to obtain the necessary geotechnical data. The results of these investigations shall be the basis for the additional site related studies specified in paragraph (b)(5) of this section.

(ii) A complete site-investigation program shall be furnished for each platform. The positioning devices used on the vessel employed in the site investigation as well as those used during the installation of the platform shall have sufficient accuracy to ensure that the data obtained are pertinent to the actual final location of the platform.

(2) *Shallow hazard survey.* (i) Consistent with the objectives of paragraph (b)(1)(i) of this section, a high-resolution or acoustic-profiling survey shall be performed to obtain information on the conditions existing at and near the surface of the seafloor; and

(ii) The information to be obtained from this survey shall include the following items, as appropriate, for the planned platform:

(A) Contours of the sea bed,

(B) Presence of any seafloor surface or near-surface anomaly or obstructions which would adversely affect platform installation at the site,

(C) Shallow faults,

(D) Gas seeps,

(E) Slump blocks,

(F) Occurrence of shallow gas, and

(G) Ice scour of seafloor sediments.

(3) *Geological survey.* (i) Background geological data shall be obtained to provide regional information that can affect the design and siting of the platform. The data shall be considered in planning the subsurface investigation.

(ii) Where necessary, the seismic activity at the site shall be assessed. Fault zones, the extent and geometry of faulting, and attenuation effects of conditions in the vicinity of the site shall be identified.

(iii) For platforms located in a producing area, the possibility of seafloor subsidence shall be considered.

(4) *Subsurface investigation and testing.* (i) The primary objective of the subsurface investigation and testing program shall be the attainment of reliable geotechnical data concerning the stratigraphic and engineering properties of the soil. These data shall be used to properly design the foundation to the desired structural safety level.

(ii) The subsurface investigation and soil testing program shall consist of adequate in situ testing, boring, and sampling to examine all important soil and rock strata. The testing program shall reveal the necessary strength, classification, and deformation properties of the soil. Further tests, as needed, shall describe the dynamic characteristics of the soil.

(iii) At least one borehole having a minimum depth of the anticipated length of the pile plus a zone of influence shall be drilled at the installation site for a pile-supported platform. Previously gathered borehole data may be used on a case-by-case basis, when approved by the Regional Supervisor. The zone of influence shall be sufficient to ensure that punch through failures will not occur. Additional boreholes of a lesser depth shall be required by the Regional Supervisor if discontinuities in the soil are indicated to exist in the area of the platform.

(iv) For a gravity-type platform foundation, the required depth of the borehole shall be equal to at least the depth of the zone of influence which the structure imposes on the supporting soil. Where possible, in situ tests shall be performed to a depth that will include the anticipated shearing failure zone.

(v) When samples from the field are sent to a laboratory for further testing, they shall be packed carefully and accurately labeled, and the results of visual inspections shall be recorded.

(vi) A summary report showing the results of the soil testing program shall be prepared. The report shall describe briefly the various field and laboratory test methods employed and shall indicate the applicability of these methods as they relate to the quality of the sample, the type of soil, and the anticipated design application.

(vii) The engineering properties of the soil to be used in the design shall be listed for each stratum. The selected design properties shall specify the uncertainties inherent in the overall testing program and in the reliability and applicability of the individual test methods.

(5) *Additional requirements.* Based on the results of the overall site investigation program, studies shall be performed, as applicable, to assess the following effects of the installed platform:

(i) Scouring potential of the seafloor,

(ii) Hydraulic instability and the occurrence of sand waves,

(iii) Instability of slopes in the area where the platform is to be placed,

(iv) Liquefaction and/or possible reduction of soil strength due to increased pore pressures, and

(v) Degradation of subsea permafrost layers.

(c) *Foundation design requirements*—(1) *General.* (i) The loadings used in the design of the foundation shall include those defined in paragraph (c)(6)(ii) of this section.

(ii) Foundation displacements shall be evaluated to ensure that they are within limits that do not impair the intended function and safety of the platform.

(iii) The soil and the platform shall be considered as an interactive system, and the results of the analysis as required in paragraphs (c)(2) through (c)(6) of this section shall be evaluated from this point of view.

(2) *Cyclic loading effects.* Evaluation of the short-term and long-term effects of cyclic loading with respect to changes in soil characteristics, whether caused by conditions during installation, seismic activity, or storms, shall be accomplished by using defensible methods.

(3) *Scour.* (i) For unprotected foundations, the depth and lateral extent of scouring, as determined in the site investigation program, shall be accounted for in design; and

(ii) If scour is not accounted for in design, either effective protection shall be furnished soon after the installation of the platform or frequent visual inspection shall be carried out, particularly after major storms.

(4) *Settlements and displacements.* (i) Based on the type and function of the platform, tolerable limits shall be established for settlements and lateral deflections. Due consideration shall be given to the effect of these movements on risers, pilings, and other components which interact with the platform;

(ii) Maximum allowable values of platform movements, as limited by these structural considerations or overall platform stability, shall be considered in the design.

(5) *Dynamic considerations.* (i) For dynamic-loading conditions, a defensible method shall be employed to simulate the interactive effects between the soil and the platform, and

(ii) The evaluation of the dynamic response of the platform shall account for, as appropriate, the nonlinear and inelastic characteristics of the soil, the possible deterioration of strength, the increased or decreased damping due to cyclic soil loading, and the influence of nearby platforms.

(6) *Loading conditions.* (i) Loadings producing the worst effects on the foundation during and after installation shall be addressed; and

(ii) In-place platform loadings to be checked shall include at least those relating to both the operating and design environmental conditions, combined in accordance with the following:

(A) Operating environmental conditions with dead and live loads appropriate to the function and operation of the platform,

(B) Design environmental conditions with dead and live loads appropriate to the function and operation of the platform, and

(C) Design environmental conditions with dead and minimum live loads appropriate to the function and operation of the platform.

(d) *Pile foundations*—(1) *General.* The following requirements apply to pile-founded platforms. Pertinent parts of these requirements dealing with steel design shall be consulted regarding the design of the steel piles.

(i) In the design of individual piles and piles in a group, the effects of axial, bending, and lateral loads shall be addressed.

(ii) The design of a pile shall reflect the interactive behavior between the soil and the pile, between the pile and the platform, and between piles in a group.

(iii) Methods of pile installation shall be consistent with the type of soil at the site and the installation equipment available. If unexpectedly high-driving resistance or other conditions lead to a failure of the pile to reach the desired penetration, the pile's capacities shall be reevaluated by considering the actual installation situation.

(iv) Pile driving shall be performed and supervised by qualified and experienced personnel. Driving records which include such information as blowcounts and estimated hammer performance and stoppages shall be retained.

(v) Where necessary, the effects of bottom instability in the vicinity of the platform shall be assessed.

(2) *Axial piles.* (i) For piles in compression, the axial capacity shall be considered to consist of the skin friction, Q_f, developed along the length of the pile and the end bearing, Q_p, at the tip of the pile. The various parameters needed to evaluate Q_f and Q_p shall be predicted by using a defensible analytical method that employs reliably obtained soil data consistent with the prediction method selected. The acceptability of any method used to predict the components of pile resistance shall be demonstrated by showing satisfactory performance of the method under conditions similar to those existing at the actual site.

(ii) The results of the dynamic pile driving analysis alone shall not be used to predict the axial load capacity of a pile.

(iii) For piles driven through clay, the estimated skin friction developed over any increment of the pile surface shall not exceed the shear strength of the clay.

(iv) The capacity of the internal plug of an open-ended pile shall be considered since it may limit the estimated end bearing to the pile.

(v) When combining side friction and end-bearing effects in determining axial pile capacity, the load deflection response of the soil-pile system shall be addressed.

(vi) For piles subjected to pullout loads, the contribution of the end resistance of the pile to its axial capacity shall not be considered. The possible variation of predicted pile-skin friction between the compressive and tensile modes of the axial-pile loading shall be considered.

(3) *Laterally loaded piles.* (i) In evaluating the pile's behavior when acted upon by lateral loadings, the combined load deflection characteristics of the soil and the pile and the pile and the platform shall be addressed.

(ii) The representation of the soil's lateral displacement when it is subjected to lateral loads shall adequately reflect the deterioration of the lateral load capacity when the soil is subjected to cyclic loading.

(iii) The description of the lateral load versus displacement characteristics for the various soil strata shall be based on constitutive data obtained from suitable soil tests. The use of empirical methods to provide the description of the soil's lateral response shall be permitted if such methods are documented.

(iv) Where applicable, the rapidly deteriorating cyclic lateral load capacity of stiff clays, especially those exhibiting the presence of a secondary structure, shall be addressed in the design.

(v) Calculation of pile deflection and stress induced by lateral loads shall account for the nonlinear interaction between the soil and the pile.

(4) *Pile groups.* Where applicable, the effects of close spacing on the load and deflection characteristics of pile groups shall be determined. The allowable load for a group, both axial and lateral, shall not exceed the sum of the apparent individual pile allowable loads.

(5) *Plastic analysis.* When the design of a platform is based on the formation collapse mechanisms associated with a plastic analysis method, influence of the soil's support on the pile shall be addressed.

(e) *Gravity platforms foundations*—(1) *General.* The following requirements apply to soil foundations for gravity platforms. Section 250.138 of this part shall be consulted regarding the design of the base slab.

(i) The influence of hydraulic and slope instability, if any, shall be determined for the structural loading cases that include the design environmental loading.

(ii) The effects of adjacent platforms and the variation of soil properties in the horizontal direction shall be considered, as appropriate.

(iii) The stability of the foundation with regard to bearing and sliding failure modes shall be investigated by employing the soil shear strengths determined with consideration of paragraphs (b)(4) and (c)(2) of this section.

(iv) When an underpressure or overpressure is experienced by the seafloor under the platform, provisions shall be made to prevent piping that could impair the integrity of the foundation.

(v) Initial, consolidation, and secondary settlements, as well as permanent horizontal displacements, shall be determined.

(vi) If the intended site is not level, the predicted tilt of the overall platform shall be based on the average bottom slope of the seafloor and the tolerance of the measuring device used in the site-investigation program. Differential settlement shall also be calculated and the tilting of the platform caused by this settlement shall be combined with the predicted structural tilt of the overall platform. Any increased loading effects caused by tilting of the platform shall be addressed in stability requirements specified for the foundation.

(2) *Stability.* (i) The bearing capacity and lateral resistance shall be calculated by considering the most unfavorable combination of loads. The long-term redistribution of bearing pressures under the base slab shall be considered to ensure that the maximum edge pressures are used in the design of the base.

(ii) The lateral resistance of the platform shall be investigated considering various potential shearing planes. The presence of any soft layers shall require special consideration.

(iii) Calculations for overturning moment and vertical forces induced by the passage of a wave shall include the vertical pressure distribution across the top of the foundation and along the seafloor. The foundation shall not lose contact with the soil due to uplift created by the maximum overturning moment.

(iv) The capacity of the foundation to resist a deep-seated bearing failure shall be analyzed.

(v) Where present, the additional effects of penetrating walls or skirts that transfer vertical and lateral loads to the soil shall be investigated for their contribution to bearing load capacity and lateral resistance.

(3) *Soil reaction on the platform.* (i) For conditions during and after installation, the reaction of the soil against all structural members seated on or penetrating into the seafloor shall be determined and accounted for in the design of these members.

(ii) The distribution of soil reactions shall be based on the results obtained in paragraphs (b)(2) and (b)(4) of this section, and the calculations of soil reactions shall account for any deviation from a plane surface, the load-deflection characteristics of the soil, and the geometry of the platform base.

(iii) Where applicable, effects of local soil stiffening, nonhomogeneous soil properties, and boulders and other obstructions shall be addressed in the design. During installation, the possibility of local contact pressures due to irregular contact between the base and the seafloor shall be considered. Contact pressures shall be added to the hydrostatic pressure.

(iv) The penetration resistance of structural elements projecting into the seafloor below the foundation structure shall be analyzed. The design of the ballasting system shall reflect uncertainties associated with achieving the required penetration of the platform.

§ 250.140 Marine operations.

(a) *General*—(1) Marine operations means all activities necessary for the transportation and installation of a platform from the time it enters the marine environment until it is fixed in place at its final destination. Marine operations generally include such activities as follows:

(i) Lifting and mooring,

(ii) Loadout or initial flotation,

(iii) Fabrication afloat,

(iv) Towing,

(v) Launching and uprighting,

(vi) Submergence,

(vii) Pile installation, and

(viii) Final field erection.

(2) The requirements of this section apply to all platforms covered by this subpart, regardless of structural type or material of construction.

(b) *Objective.* The structural strength and integrity of a platform shall not be reduced or otherwise jeopardized by the performance of the activities required to install the platform on site. The type and magnitude of loads and load combinations to which a platform will be exposed during marine operations shall be the subject of an analysis pursuant to paragraph (c) of this section, except where the use of proven and well-controlled methods of fabrication and installation are proposed and justified. Sufficient equipment shall be provided to ensure installation of the platform in a safe and well-controlled manner.

(c) *Analysis.* (1) Analyses shall be performed to determine the type and magnitude of the loads and load combinations to which the platform will be exposed during the performance of marine operations.

(2) Analyses shall be performed to ensure that the structural design is sufficient to withstand the type and magnitude of the loads and load combinations determined, in accordance with paragraph (c)(1) of this section, without loss or degradation of structural integrity.

(3) Analyses shall be performed to ensure that the platform or its means of support has sufficient hydrostatic stability and reserve buoyancy to allow for successful execution of all phases of marine operations.

§ 250.141 Inspection during construction.

(a) *General*—(1) *Coverage.* All pile-supported and gravity platforms covered by this subpart shall be inspected during the construction phase. Additional requirements for steel pile-supported platforms are contained in paragraph (b) of this section, and additional requirements pertaining to concrete-gravity platforms are contained in paragraph (c) of this section. The phases of construction subject to inspection include material manufacture, fabrication, loadout, transportation, positioning, installation, and final field erection.

(2) *Objective.* Inspections during construction are to verify that the platform is constructed in accordance with the approved construction plan. Any unusual or innovative application of materials or methods of construction not adequately covered by the requirements of this section shall receive special attention during compliance inspections relevant to its effect on the integrity of the platform.

(3) *Remedial action.* If construction inspection results reveal that materials, procedures, or workmanship deviate significantly from the approved design, remedial action shall be taken.

(4) *Identification of materials.* The origin of materials used in the platform and the results of relevant material tests for all significant structural materials shall be retained and made readily available for inspection by MMS representatives during all stages of construction. Records shall be kept of the locations throughout the platform of

the various heat numbers for such materials.

(b) *Steel pile-supported platforms*—(1) *Scope.* Inspections of steel pile-supported platforms shall address the following topics, as appropriate:

(i) Material quality and forming,

(ii) Welder and welding procedure qualifications,

(iii) Weld inspection,

(iv) Tolerances and alignments, and

(v) Corrosion-control systems.

(2) *Material quality and forming.* Inspection shall verify that all materials employed are of good quality and suitable for their intended service as specified in the approved design. Inspection shall ensure the compliance of materials to the relevant material standards selected in the design of the platform. Inspection shall ensure that formed members satisfy the dimensional tolerances listed in the design.

(3) *Welder and welding-procedure qualifications.* (i) Welders shall be tested and possess a current welder's certification.

(ii) All welding procedures to be employed shall be tested and certified for the production of satisfactory welds. Welding procedures previously tested and certified shall be considered prequalified.

(4) *Weld inspection.* (i) Inspection shall include, but not be limited to, visual inspection of all welds and representative magnetic particle or dye penetrant inspection of welds of Weld Classes A and B materials (see § 250.137(a)(4) of this part) not subjected to ultrasonic or radiographic inspection. The extent of ultrasonic or radiographic inspection shall be specified and shall emphasize, but not be confined to, welds of Weld Class A materials.

(ii) The extent and methods of inspection shall be consistent with the classification of applications (see § 250.137(a)(4) of this part) of the area being examined.

(iii) Any welding not meeting the acceptance criteria specified in the inspection plan shall be rejected and appropriate remedial action taken.

(5) *Tolerances and alignments.* Overall dimensional tolerances, forming tolerances, and local alignment tolerances shall be commensurate with those considered in developing the structural design. Inspections shall ensure that the dimensional tolerance criteria are being met. Out of roundness of structural elements for which buckling is the anticipated mode of failure shall receive individual inspection.

(6) *Corrosion-control systems.* Corrosion-control systems employed on the platform shall be inspected to ensure that they are installed as specified in the approved design. Inspection shall ensure that proper protection against galvanic effects, especially in locations where nonferrous materials are used in conjunction with steel, has been provided in the corrosion-control system.

(7) *Additional inspection items.* (i) The provisions of paragraphs (b)(2) through (b)(6) of this section relate only to matters directly affecting the onshore construction phases of the platform. Other items relating to the onshore construction site and the construction phases from loadout to final erection shall also be performed.

(ii) The construction site shall be inspected to ensure that adequate consideration has been given to the following items:

(A) Support of the platform during construction,

(B) Employment of a sufficient number of certified welders and inspectors to maintain an adequate quality of work, and

(C) Weathertight storage of welding consumables under conditions specified by their manufacturers.

(iii) Inspection shall verify that the following operations have been accomplished in a manner conforming to approved plans or drawings:

(A) Loadout,

(B) Tie down,

(C) Positioning at the site,

(D) Installation (see § 250.139(d)(1)(v) of this part for piles), and

(E) Final field erection.

(iv) To determine if overstressing of the platform during transportation has occurred, towing records shall be reviewed to ascertain if conditions during towing operations exceeded those employed in the analyses required by § 250.140(c) of this part.

(v) When the inspections indicate that overstressing has occurred during loadout, transportation, or installation, the affected parts of the platform shall be surveyed to determine the extent of actual damage, if any. Where necessary, a reevaluation of the structural capacity shall be carried out, considering the results of the survey.

(8) *Records.* The following construction records shall be compiled, retained, and made available for inspection by MMS representatives:

(i) Mill certificates,

(ii) Weld-procedure qualification records,

(iii) Weld inspection records,

(iv) Dimensional tolerance reports,

(v) Towing records, and

(vi) Pile driving records.

(c) *Concrete-gravity platforms.* (1) *Scope.* Inspection of concrete-gravity platforms shall address the following topics, as appropriate:

(i) Preparation for concrete production and placement;

(ii) Batching, mixing, and placing concrete;

(iii) Form removal and concrete curing;

(iv) Pretensioning and grouting;

(v) Joints; and

(vi) Finished concrete.

(2) *Preparation for concrete production and placement.* (i) Inspection shall ensure that the pertinent physical properties of cement, reinforcing steel, prestressing tendons, and appurtenances comply with those specified in the approved design.

(ii) Forms and shoring supporting the forms shall be inspected to ensure that they are adequate in number and type and are located correctly.

(iii) The dimensional tolerances of the forms shall be inspected to ensure that the finished dimensional tolerances are comparable to those allowed for in the approved design.

(iv) Reinforcing steel, prestressing tendons, post-tensioning ducts, anchorages, and any other embedded steel shall be inspected, as appropriate, for size, bending, spacing, location, firmness of installation, surface condition, vent locations, proper duct coupling, and duct capping.

(3) *Batching, mixing, and placing concrete.* (i) Inspections shall be performed to ensure that the procedures for the production and placement of concrete provide a well-mixed and well-compacted concrete. The procedures shall also limit segregation, loss of material, contamination, and premature initial set during all operations.

(ii) Inspection shall verify that the mix components of each batch of concrete are properly proportioned and within allowable variations specified in the approved design. Inspection shall ensure that the water/cement ratio of each batch is within the limit specified in § 250.138(b)(7) of this part.

(iii) Aggregate gradation, cleanliness, moisture content, and unit weight shall be tested. The frequency of testing shall be determined taking into account the uniformity of the supply source, volume of concrete used, and variations of atmospheric conditions.

(iv) Mix water shall be tested for purity following specified methods and schedules.

(v) Testing during the production of concrete shall be performed to monitor, as a minimum, the following concrete qualities:

(A) Consistency,

(B) Air content, and

(C) Strength.

(4) *Form removal and concrete curing.* (i) Inspection shall ensure that forms and form supports are not removed until the platform has attained sufficient strength to bear its own weight, construction loads, and anticipated environmental loads without undue deformation and that they are removed according to schedule.

(ii) Inspection shall ensure that curing of concrete is accomplished in accordance with the provisions of a predetermined procedure.

(iii) Where the construction procedures require the submergence of recently placed concrete, inspection shall ensure that methods for protecting the concrete from the effects of salt water are properly executed.

(5) *Pretensioning and grouting.* (i) Inspection shall verify that the sequence of tendon tensioning and the resulting elongation and force are in accordance with provisions specified in the approved design.

(ii) Pretensioning or post-tensioning stress shall be determined by measuring both tendon elongation and tendon force. Inspection shall verify that the variation of measurements does not exceed a specified amount.

(iii) Inspection shall verify that grout mix proportions and ambient conditions during mixing are in accordance with provisions designated in the approved design. Tests for grout, viscosity expansion, bleeding, compressive strength, and setting time shall be performed to ensure compliance with design requirements. Procedures shall be observed to ensure that ducts are completely filled.

(iv) Anchorages shall be inspected to ensure that they are located and sized as specified in the design and are provided with adequate cover to mitigate the effects of corrosion.

(6) *Joints.* Where appropriate, leak testing of construction joints shall be performed by using specified procedures. When deciding which joints to inspect, consideration shall be given to the hydrostatic head on the subject joint during normal operation, the consequence of a leak at the subject joint, and the ease of repair once the platform is in service.

(7) *Finished concrete.* (i) The surface of the hardened concrete shall be completely inspected for cracks, honeycombing, popouts, spalling, and other surface imperfections.

(ii) The platform shall be examined by using a calibrated rebound hammer or a similar nondestructive examination device. Inspection shall verify that the results of surface inspection, cylinder strength test, or nondestructive examination are in accordance with the approved design criteria.

(iii) The completed sections of the platform shall be checked for compliance to specified design tolerances of thickness and alignment and, to the extent practicable, the location of reinforcing and prestressing steel and post-tensioning ducts.

(8) *Additional inspection items.* (i) While the provisions of paragraphs (c)(2) through (c)(7) of this section relate only to some matters directly affecting the onshore or nearshore construction phases of the platform, other items relating to such phases and from loadout to final erection shall also be considered.

(ii) Inspection shall ensure that adequate consideration has been given the following items:

(A) Support of the structure during construction,

(B) Employment of a sufficient number of competent workmen and inspectors to maintain an adequate quality of work,

(C) Storage of cement and prestressing tendons in weathertight areas,

(D) Storage of admixtures and epoxies according to manufacturers' specifications, and

(E) Storage of aggregates to limit segregation, contamination by deleterious substances, and moisture variations within the stockpile.

(iii) Inspection shall verify that the following operations, as applicable to the planned platform, have been accomplished in a manner conforming to approved plans or drawings developed for these operations:

(A) Loadout,

(B) Towing arrangements,

(C) Positioning at the site,

(D) Installation, and

(E) Final field erection.

(iv) To determine if overstressing of the platform during transportation has occurred, towing records shall be reviewed to ascertain if conditions during the towing operations exceeded those employed in the analyses required by § 250.140(c) of this part.

(9) *Records.* The following construction records shall be compiled, retained, and made available for inspection by MMS representatives:

(i) Material certificates and test reports;

(ii) Tensioning and grouting records;

(iii) Concreting records including weight, moisture content, mix proportions, test methods and results, ambient conditions during the pour, and test equipment calibration data;

(iv) Deviations from design or fabrication specifications and repairs carried out;

(v) Towing records; and

(vi) Data on initial structural settlements.

§ 250.142 Periodic inspection and maintenance.

(a) All platforms installed in the OCS shall be inspected periodically in accordance with the provisions of API RP2A, section 7, Surveys. However, use of an inspection interval which exceeds 5 years shall require approval by the Regional Supervisor. Proper maintenance shall be performed to assure the structural integrity of the platform as a workbase for oil and gas operations.

(b) A report shall be submitted annually on November 1 to the Regional Supervisor stating which platforms have been inspected in the preceding 12 months, the extent and area of inspection, and the type of inspection employed, i.e., visual, magnetic particle, ultrasonic testing. A summary of the testing results shall be submitted indicating what repairs, if any, were needed and the overall structural condition of the platform.

§ 250.143 Platform removal and location clearance.

(a) The lessee shall remove all structures in a manner approved by the Regional Supervisor to assure that the location has been cleared of all obstructions to other activities in the area.

(b) All platforms (including casing, wellhead equipment, templates, and piling) shall be removed by the lessee to a depth of at least 15 feet below the ocean floor or to a depth approved by the Regional Supervisor based upon the type of structure or ocean-bottom conditions.

(c) The lessee shall verify by appropriate means that the location has been cleared of all obstructions. The results of the location clearance survey shall be submitted to the Regional Supervisor by means of a letter from the company performing the work certifying that the area was cleared of all obstructions, the date the work was performed, the extent of the area surveyed, and the survey method used.

§ 250.144 Records.

The lessee shall compile, retain, and make available to Minerals Management Service representatives for the functional life of all platforms, the as-built structural drawings, the design assumptions and analyses, a summary of the nondestructive examination records, and the inspection results from platform inspections required by § 250.142 of this part.

Subpart J—Pipelines and Pipeline Rights-of-Way

§ 250.150 General requirements.

(a) Pipelines and associated valves, flanges, and fittings shall be designed, installed, operated, maintained, and abandoned to provide safe and pollution-free transportation of fluids in a manner which does not unduly interfere with other uses in the Outer Continental Shelf (OCS).

(b) An application shall be submitted to the Regional Supervisor and approval obtained prior to the installation, modification, or abandonment of a pipeline which qualifies as a lease term pipeline (see § 250.151, Definitions) and prior to the installation of a right-of-way pipeline or the modification or relinquishment of a pipeline right-of-way.

(c) A pipeline which qualifies under the Department of the Interior's (DOI) jurisdiction (DOI pipeline) shall meet the requirements of § 250.150 through 250.158 of this subpart. The DOI's exclusive jurisdiction with respect to pipeline activities extends upstream from the outlet flange at each facility where produced hydrocarbons are first separated, dehydrated, or otherwise processed to each production well in the OCS. In addition, those pipelines necessary for the development of a lease, e.g., gas-lift gas or supply pipelines, are under DOI's exclusive jurisdiction.

(d) A pipeline which qualifies as a right-of-way pipeline (see § 250.151, Definitions) shall not be installed until a right-of-way has been requested and granted in accordance with this subpart.

(e)(1) The Regional Supervisor may suspend any pipeline operation upon a determination by the Regional Supervisor that continued activity would threaten or result in serious, irreparable, or immediate harm or damage to life (including fish and other aquatic life), property, mineral deposits, or the marine, coastal, or human environment.

(2) The Regional Supervisor may also suspend pipeline operations or a right-of-way grant if the Regional Supervisor determines that the lessee or right-of-way holder has failed to comply with a provision of the Act or any other applicable law, a provision of these or other applicable regulations, or a condition of a permit or right-of-way grant.

(3) The Secretary of the Interior (Secretary) may cancel a pipeline permit or right-of-way grant in accordance with 43 U.S.C. 1334(a)(2). A right-of-way grant may be forfeited in accordance with 43 U.S.C. 1334(e).

§ 250.151 Definitions.

Terms used in this subpart shall have the meanings given below:

"Lease term pipelines" are those pipelines owned and operated by a lessee or operator and are wholly contained within the boundaries of a single lease, unitized leases, or contiguous (not cornering) leases of that lessee or operator.

"Pipelines" are the piping, risers, and appurtenances installed for the purpose of transporting oil, gas, sulphur, and produced water. (Piping confined to a production platform or structure is covered in Subpart H, Production Safety Systems, and is excluded from this subpart.)

"Right-of-way pipelines" are those pipelines which—

(a) Are contained within the boundaries of a single lease or group unitized leases but are not owned and operated by the lessee or operator of that lease or unit,

(b) Are contained within the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator,

(c) Are contained within the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or

(d) Crosses any portion of an unleased block(s).

§ 250.152 Design requirements for DOI pipelines.

(a) The internal design pressure for steel pipe shall be determined in accordance with the following formula:

$$P = \frac{2(S)(t)}{D} X(F)(E)(T)$$

For limitations see section 841.121 of American National Standards Institute (ANSI) B31.8 Where—

P = Internal design pressure in pounds per square inch (psi).

S = Specified minimum yield strength, in psi, stipulated in the specification under which the pipe was purchased from the manufacturer or determined in accordance with section 811.253(h) of ANSI B31.8.

D = Nominal outside diameter of pipe, in inches.

t = Nominal wall thickness, in inches.

F = Construction design factor of 0.72 for the submerged component and 0.60 for the riser component.

E = Longitudinal joint factor obtained from Table 841.1B of ANSI B31.8. (See also section 811.253(d)).

T = Temperature derating factor obtained from Table 841.1C of ANSI B31.8.

(b)(1) Pipeline valves shall meet the minimum design requirements of American Petroleum Institute (API) Spec 6A, API Spec 6D, or the equivalent. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

(2) Pipeline flanges and flange accessories shall meet the minimum design requirements of ANSI B16.5, API Spec 6A, or the equivalent. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(3) Pipeline fittings shall have pressure-temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting shall at least be equal to the computed bursting strength of the pipe.

(c) The maximum allowable operating pressure (MAOP) shall not exceed the least of the following:

(1) Internal design pressure of the pipeline, valves, flanges, and fittings;

(2) Eighty percent of the hydrostatic pressure test (HPT) of the pipeline; or

(3) If applicable, the MAOP of the receiving pipeline when the proposed pipeline and the receiving pipeline are connected at a subsea tie-in.

(d) If the maximum source pressure (MSP), exceeds the pipeline's MAOP, redundant safety devices meeting the requirements of section A9 of API RP 14C shall be installed and maintained. Pressure safety valves (PSV) may be used only after a determination by the Regional Supervisor that the pressure will be relieved in a safe and pollution-free manner. The setting level at which the primary and redundant safety equipment actuates shall not exceed the pipeline's MAOP.

(e) Pipelines shall be provided with an external protective coating capable of minimizing underfilm corrosion and a cathodic protection system designed to mitigate corrosion for at least 20 years.

(f) Pipelines shall be designed and maintained to mitigate any reasonably anticipated detrimental effects of water currents, storm or ice scouring, soft bottoms, mud slides, earthquakes, subfreezing temperatures, and other environmental factors.

§ 250.153 Installation, testing, and repair requirements for DOI pipelines.

(a)(1) Pipelines greater than 8-5/8 inches in diameter and installed in water depths of less than 200 feet shall be buried to a depth of at least 3 feet

unless they are located in pipeline congested areas or seismically active areas as determined by the Regional Supervisor. Nevertheless, the Regional Supervisor may require burial of any pipeline if the Regional Supervisor determines that such burial will reduce the likelihood of environmental degradation or that the pipeline may constitute a hazard to trawling operations or other uses. A trawl test or diver survey may be required to determine whether or not pipeline burial is necessary or to determine whether a pipeline has been properly buried.

(2) Pipeline valves, taps, tie-ins, capped lines, and repaired sections that could be obstructive shall be provided with at least 3 feet of cover unless the Regional Supervisor determines that such items present no hazard to trawling or other operations. A protective device may be used to cover an obstruction in lieu of burial if it is approved by the Regional Supervisor prior to installation.

(3) Pipelines shall be installed with a minimum separation of 18 inches at pipeline crossings and from obstructions.

(4) Pipeline risers installed after [Insert date of publication in the **Federal Register**] shall be protected from physical damage that could result from contact with floating vessels. Riser protection on pipelines installed on or before [Insert date of publication in the **Federal Register**] may be required when the Regional Supervisor determines that significant damage potential exists.

(b)(1) Pipelines shall be hydrostatically tested with water at a stabilized pressure of at least 1.25 times the MAOP for at least 8 hours when installed, relocated, uprated, or reactivated after being out-of-service for more than 1 year.

(2) Prior to returning a pipeline to service after a repair, the pipeline shall be pressure tested with water or processed natural gas at a minimum stabilized pressure of at least 1.25 times the MAOP for at least 2 hours.

(3) Pipelines shall not be pressure tested at a pressure which produces a stress in the pipeline in excess of 95 percent of the specified minimum-yield strength of the pipeline. A temperature recorder measuring test fluid temperature synchronized with a pressure recorder along with deadweight test readings shall be employed for all pressure testing. When a pipeline is pressure tested, no observable leakage shall be allowed. Pressure gauges and recorders shall be of sufficient accuracy to verify that leakage is not occurring.

(c) When a pipeline is repaired utilizing a clamp, the clamp shall be a full encirclement clamp able to withstand the anticipated pipeline pressure.

(4) The Regional Supervisor may require pressure testing of pipelines to verify the integrity of the system when the Regional Supervisor determines that there is a reasonable likelihood that the line has been damaged or weakened by external or internal conditions.

§ 250.154 Safety equipment requirements for DOI pipelines.

(a) The lessee shall ensure the proper installation, operation, and maintenance of safety devices required by this section on all incoming, departing, and crossing pipelines on platforms.

(b)(1) Incoming pipelines to a platform shall be equipped with a flow safety valve (FSV).

(2) Incoming pipelines delivering to a production platform shall be equipped with an automatic shutdown valve (SDV) immediately upon boarding the platform. The SDV shall be connected to the automatic- and remote-emergency shut-in systems.

(3) Departing pipelines receiving production from production facilities shall be protected by high- and low-pressure sensors (PSHL) to directly or indirectly shut in all production facilities. The PSHL shall be set at 15 percent above and below the normal operating pressure range. However, high pilots shall not be set above the pipeline's MAOP.

(4) Crossing pipelines on production or manned nonproduction platforms which do not receive production from the platform shall be equipped with an SDV immediately upon boarding the platform. The SDV shall be operated by a PSHL on the departing pipelines and connected to the platform automatic- and remote-emergency shut-in systems.

(5) The Regional Supervisor may require that oil pipelines be equipped with a metering system to provide a continuous volumetric comparison between the input to the line at the structure(s) and the deliveries onshore. The system shall include an alarm system and shall be of adequate sensitivity to detect variations between input and discharge volumes. In lieu of the foregoing, a system capable of detecting leaks in the pipeline may be substituted with the approval of the Regional Supervisor.

(6) Pipelines incoming to a subsea tie-in shall be equipped with a block valve and an FSV. Bidirectional pipelines connected to a subsea tie-in shall be equipped with only a block valve.

(7) Gas-lift or water-injection pipelines on unmanned platforms need only be equipped with an FSV installed immediately upstream of each casing annulus or the first inlet valve on the christmas tree.

(8) Bidirectional pipelines shall be equipped with a PSHL and an SDV immediately upon boarding each platform.

(9) Pipeline pumps shall comply with Section A7 of API RP 14C. The setting levels for the PSHL devices are specified in paragraph (b)(3) of this section.

(c) If the required safety equipment is rendered ineffective or removed from service on pipelines which are continued in operation, an equivalent degree of safety shall be provided. The safety equipment shall be identified by the placement of a sign on the equipment stating that the equipment is rendered ineffective or removed from service.

§ 250.155 Inspection requirements for DOI pipelines.

(a) Pipeline routes shall be inspected at time intervals and methods prescribed by the Regional Supervisor for indication of pipeline leakage. The results of these inspections shall be retained for at least 2 years and be made available to the Regional Supervisor upon request.

(b) When pipelines are protected by rectifiers or anodes for which the initial life expectancy of the cathodic protection system either cannot be calculated or calculations indicate a life expectancy of less than 20 years, such pipelines shall be inspected annually by taking measurements of pipe-to-electrolyte potential measurements.

§ 250.156 Abandonment and out-of-service requirements for DOI pipelines.

(a)(1) A pipeline may be abandoned in place if, in the opinion of the Regional Supervisor, it does not constitute a hazard to navigation, commercial fishing operations, or unduly interfere with other uses in the OCS. Pipelines to be abandoned in place shall be flushed, filled with seawater, cut, and plugged with the ends buried at least 3 feet.

(2) Pipelines abandoned by removal shall be pigged, unless the Regional Supervisor determines that such procedure is not practical, and flushed with water prior to removal.

(b)(1) Pipelines taken out-of-service shall be blind flanged or isolated with a closed block valve at each end.

(2) Pipelines taken out-of-service for a period of more than 1 year shall be flushed and filled with inhibited seawater.

(3) Pipelines taken out-of-service shall be returned to service within 5 years or be abandoned in accordance with the

requirements of paragraphs (a) (1) or (2) of this section.

§ 250.157 Applications.

(a) Applications for the approval of the installation of a lease term pipeline or for the granting of a right-of-way shall be submitted in quadruplicate to the Regional Supervisor and shall include the following:

(1) Plat(s) drawn to a scale specified by the Regional Supervisor showing major features and other pertinent data including area, lease, and block designations; water depths; route; length in Federal waters; width of right-of-way, if applicable; connecting facilities; size; product(s) to be transported with anticipated gravity or density; burial depth; direction of flow; X-Y coordinates of key points; and the location of other pipelines that will be connected to or crossed by the proposed pipeline(s). The initial and terminal points of the pipeline and any continuation into State jurisdiction shall be accurately located even if the pipeline is to have an onshore terminal point. A plat(s) submitted for a pipeline right-of-way shall bear a signed certificate upon its face by the engineer who made the map that certifies that the right-of-way is accurately represented upon the map and that the design characteristics of the associated pipeline are in accordance with applicable regulations.

(2) A schematic drawing showing the size, weight, grade, wall thickness, and type of line pipe and risers; pressure-regulating devices (including back-pressure regulators); sensing devices with associated pressure-control lines; PSV's and settings; SDV's, FSV's, and block valves; and manifolds. This schematic drawing shall also show input source(s), e.g., wells, pumps, compressors, and vessels; maximum input pressure(s); the rated working pressure, as specified by ANSI or API, of all valves, flanges, and fittings; the initial receiving equipment and its rated working pressure; and associated safety equipment and pig launchers and receivers.

(3) General information as follows:

(i) Description of cathodic protection system. If pipeline anodes are to be used, specify the type, size, weight, number, spacing, and anticipated life;

(ii) Description of external pipeline coating system;

(iii) Description of internal protective measures;

(iv) Specific gravity of the empty pipe;

(v) MSP;

(vi) MAOP and calculations used in its determination;

(vii) Hydrostatic test pressure, medium, and period of time that the line will be tested;

(viii) MAOP of the receiving pipeline or facility,

(ix) Proposed date for commencing installation and estimated time for construction; and

(x) Type of protection to be afforded crossing pipelines, subsea valves, taps, and manifold assemblies, if applicable.

(4) The application shall include a description of any additional design precautions which were taken to enable the pipeline to withstand the effects of water currents, storm or ice scouring, soft bottoms, mudslides, earthquakes, permafrost, and other environmental factors.

(5) The application shall include a shallow hazards survey report and, if applicable, an archaeological resource report which covers the entire length of the pipeline. However, with approval of the Regional Supervisor, a shallow hazards analysis may be included in a lease term pipeline application in lieu of the shallow hazards survey report. In addition, the Regional Supervisor may require the submission of the data upon which the report or analysis is based.

(b) Applications to modify an approved lease term pipeline or right-of-way grant shall be submitted in quadruplicate to the Regional Supervisor. These applications need only address those items in the original application affected by the proposed modification.

(c) Applications to abandon a lease term pipeline or relinquish a right-of-way grant shall be submitted in triplicate to the Regional Supervisor and shall include the following:

(1) Reason for operation,

(2) Proposed procedures,

(3) "As-built" location plat,

(4) Length in feet of segment to be abandoned or relinquished, and

(5) Length in feet of segment remaining.

§ 250.158 Reports.

(a) The lessee, or right-of-way holder, shall notify the Regional Supervisor at least 48 hours prior to commencing the installation or relocation of a pipeline or conducting a pressure test on a pipeline.

(b) The lessee or right-of-way holder shall submit a report to the Regional Supervisor within 90 days after completion of any pipeline construction. The report, submitted in triplicate, shall include an "as-built" location plat drawn to a scale specified by the Regional Supervisor showing the location, length in Federal waters, and X–Y coordinates of key points; the completion date; the proposed date of first operation; and the HPT data. Pipeline right-of-way "as-built" location plats shall be certified by a registered engineer or land surveyor and show the boundaries of the right-of-way as granted. If there is a substantial deviation of the pipeline route as granted in the right-of-way, the report shall include a discussion of the reasons for such deviation.

(c) The lessee or right-of-way holder shall report to the Regional Supervisor any pipeline taken out of service. If the period of time in which the pipeline is out of service is greater than 60 days, written confirmation is also required.

(d) The lessee or right-of-way holder shall report to the Regional Supervisor when any required pipeline safety equipment is taken out of service for more than 12 hours. The Regional Supervisor shall be notified when the equipment is returned to service.

(e) The lessee or right-of-way holder shall notify the Regional Supervisor prior to the repair of any pipeline or as soon as practicable. A detailed report of the repair of a pipeline or pipeline component shall be submitted to the Regional Supervisor within 30 days after completion of the repairs. The report shall include the following:

(1) Description of repairs,

(2) Results of pressure test, and

(3) Date returned to service.

(f) The Regional Supervisor may require that DOI pipeline failures be analyzed and that samples of a failed section be examined in a laboratory to assist in determining the cause of the failure. A comprehensive written report of the information obtained shall be submitted by the lessee to the Regional Supervisor as soon as available.

(g) If the effects of scouring, soft bottoms, or other environmental factors are observed to be detrimentally affecting a pipeline, a plan of corrective action shall be submitted to the Regional Supervisor for approval within 30 days of the observation. A report of the remedial action taken shall be submitted to the Regional Supervisor by the lessee or right-of-way holder within 30 days after completion.

(h) The results and conclusions of measurements of pipe-to-electrolyte potential measurements taken annually on DOI pipelines in accordance with § 250.155(b) of this part shall be submitted to the Regional Supervisor by the lessee before March of each year.

§ 250.159 General requirements for a pipeline right-of-way grant.

(a)(1) In addition to applicable requirements of §§ 250.150 through 250.158 and other regulations of this

part, regulations of the Department of Transportation, Department of the Army, and the Federal Energy Regulatory Commission (FERC), when a pipline qualifies as a right-of-way pipeline, the pipeline shall not be installed until a right-of-way has been requested and granted in accordance with this subpart. The right-of-way grant is issued pursuant to 43 U.S.C. 1334(e) and may be acquired and held only by citizens and nationals of the United States; aliens lawfully admitted for permanent residence in the United States as defined in 8 U.S.C. 1101(a)(20); private, public, or municipal corporations organized under the laws of the United States or territory thereof, the District of Columbia, or of any State; or associations of such citizens, nationals, resident aliens, or private, public, or municipal corporations, States, or political subdivisions of States.

(2) A right-of-way shall include the site on which the pipeline and associated structures are to be situated, shall not exceed 200 feet in width unless safety and environmental factors during construction and operation of the associated right-of-way pipeline require a greater width, and shall be limited to the area reasonably necessary for pumping stations or other accessory structures.

(b)(1) The applicant shall furnish the Regional Supervisor a corporate surety bond in the sum of $300,000 conditioned on compliance with all the terms of the grant. Such bond shall not be required if the applicant already maintains or furnishes a bond in the sum of $300,000 conditioned on compliance with the terms of all right-of-way grants held by the applicant in the OCS for the area in which the grant to be issued is situated. This bond shall be in addition to any bond required of a lessee in 30 CFR Part 256.

(2) For the purposes of this paragraph, listed below are the four areas:

(i) The Alaska OCS Region,

(ii) The Atlantic OCS Region,

(iii) The Gulf of Mexico OCS Region, and

(iv) The Pacific OCS Region

(3) If, as the result of a default, the surety on a right-of-way grant bond makes payment to the Government of any indebtedness under a grant secured by the bond, the face amount of such bond and the surety's liability shall be reduced by the amount of such payment.

(4) After a default, a new bond in the amount of $300,000 shall be posted within 6 months or such shorter period as the Regional Supervisor may direct. Failure to post a new bond shall be grounds for forfeiture of all grants covered by the defaulted bond.

(c) An applicant, by accepting a right-of-way grant, agrees to comply with the following requirements:

(1) The right-of-way holder shall comply with applicable laws and regulations and the terms of the grant.

(2) For the first calendar year, or fraction thereof, and annually thereafter, the right-of-way holder shall pay MMS, in advance, an annual rental of $15 for each statute mile, or fraction thereof, traversed by the right-of-way and $75 for each area to be used as a site for an accessory to the right-of-way pipeline including, but not limited to, a platform. Payments may be on an annual basis, for a 5-year period, or for multiples of 5 years.

(3) The granting of the right-of-way shall be subject to the express condition that the rights granted shall not prevent or interfere in any way with the management, administration, or the granting of other rights by the United States, either prior or subsequent to the granting of the right-of-way. Moreover, the holder agrees to allow the occupancy and use by the United States, its lessees, or other right-of-way holders, of any part of the right-of-way grant not actually occupied or necessarily incident to its use for any necessary operations involved in the management, administration, or the enjoyment of such other granted rights.

(4) If any site, structure, or object of historical or archeological significance should be discovered during the conduct of any operations within the right-of-way, the right-of-way holder shall immediately report such findings to the Regional Supervisor and make every reasonable effort to preserve and protect the cultural resource from damage until the Regional Supervisor has given directions as to its preservation.

(5) The Regional Supervisor shall be kept informed at all times of the right-of-way holder's address and, if a corporation, the address of its principal place of business and the name and address of the officer or agent authorized to be served with process.

(6) The right-of-way holder shall pay the United States or its lessees or right-of-way holders, as the case may be, the full value of all damages to the property of the United States or its said lessees or right-of-way holders and shall indemnify the United States against any and all liability for damages to life, person, or property arising from the occupation and use of the area covered by the right-of-way grant.

(7)(i) The holder of a right-of-way oil or gas pipeline shall transport or purchase oil or natural gas produced from submerged lands in the vicinity of the pipeline without discrimination and in such proportionate amounts as the FERC may, after a full hearing with due notice thereof to the interested parties, conservation and the prevention of waste.

(ii) Unless otherwise exempted by FERC pursuant to 43 U.S.C. 1334(f)(2), the holder shall—

(A) Provide open and nondiscriminatory access to a right-of-way pipeline to both owner and nonowner shippers, and

(B) Comply with the provisions of 43 U.S.C. 1334(f)(1)(B) under which FERC may order an expansion of the throughput capacity of a right-of-way pipeline which is approved after September 18, 1978, and which is not located in the Gulf of Mexico or the Santa Barbara Channel.

(8) The area covered by a right-of-way and all improvements thereon shall be kept open at all reasonable times for inspection by the Minerals Management Service (MMS). The right-of-way holder shall make available all records relative to the design, construction, operation, maintenance and repair, and investigations on or with regard to such area.

(9) Upon relinquishment, forfeiture, or cancellation of a right-of-way grant, the right-of-way holder shall remove all platforms, structures, domes over valves, pipes, taps, and valves along the right-of-way. All of these improvements shall be removed by the holder within 1 year of the effective date of the relinquishment, forfeiture, or cancellation unless this requirement is waived in writing by the Regional Supervisor. All such improvements not removed within the time provided herein shall become the property of the United States but that shall not relieve the holder of liabillty for the cost of their removal or for restoration of the site. Furthermore, the holder is responsible for accidents or damages which might occur as a result of failure to timely remove improvements and equipment and restore a site. An application for relinquishment of a right-of-way grant shall be filed in accordance with § 250.164 of this part.

(d) Failure to comply with the Act, regulations, or any conditions of the right-of-way grant prescribed by the Regional Supervisor shall be grounds for forfeiture of the grant in an appropriate judicial proceeding instituted by the United States in any U.S. District Court having jurisdiction in accordance with the provisions of 43 U.S.C. 1349.

(e) Any right-of-way granted under the provisions of this subpart remains in effect as long as the associated pipeline is properly maintained and used for the purpose for which the grant was made, unless otherwise expressly stated in the grant. Temporary cessation or suspension of pipeline operations shall not cause the grant to expire. However, if the purpose of the grant ceases to exist or use of the associated pipeline is permanently discontinued for any reason, the grant shall be deemed to have expired.

§ 250.160 Applications for a pipeline right-of-way grant.

(a) An application for a new or modified pipeline right-of-way grant shall be submitted in quadruplicate to the Regional Supervisor. It shall address those items required by § 250.157 (a) or (b) of this part, as applicable. It shall also state the primary purpose for which the right-of-way is to be used. If the right-of-way has been utilized prior to the time the application is made, the application shall state the date such utilization commenced, by whom, and the date the applicant obtained control of the improvement. A nonrefundable filing fee of $1,400 and the rental required under § 250.159(c)(2) of this part shall accompany a new right-of-way application. An application to modify an approved right-of-way grant shall be accompanied by the additional rental required under § 250.159(c)(2), if applicable. A separate application shall be filed for each right-of-way.

(b)(1) An individual applicant shall submit a statement of citizenship or nationality with the application. An applicant who is an alien lawfully admitted for permanent residence in the United States shall also submit evidence of such status with the application.

(2) If the applicant is an association (including a partnership), the application shall also be accompanied by a certified copy of the articles of association or appropriate reference to a copy of such articles already filed with MMS and a statement as to any subsequent amendments.

(3) If the applicant is a corporation, the application shall also include the following:

(i) A statement certified by the Secretary or Assistant Secretary of the corporation with the corporate seal showing the State in which it is incorporated and the name of the person(s) authorized to act on behalf of the corporation, or

(ii) In lieu of such a statement, an appropriate reference to statements or records previously submitted to MMS (including material submitted in compliance with prior regulations).

(c) The application shall include a list of every lessee and right-of-way holder whose lease or right-of-way is intersected by the proposed right-of-way. The application shall also include a statement that a copy of the application has been sent by registered or certified mail to each such lessee or right-of-way holder.

(d) The applicant shall include in the application an original and three copies of a completed Nondiscrimination in Employment form (YN 3341-1 dated July 1982). These forms are available at each MMS regional office.

§ 250.161 Granting a pipeline right-of-way.

(a) In considering an application for a right-of-way, the Regional Supervisor shall consider the potential effect of the associated pipeline on the human, marine, and coastal environments, life (including aquatic life), property, and mineral resources in the entire area during construction and operational phases. The Regional Supervisor shall prepare an environmental analysis in accordance with applicable policies and guidelines. To aid in the evaluation and determinations, the Regional Supervisor may request and consider views and recommendations of appropriate Federal Agencies, hold public meetings after appropriate notice, and consult, as appropriate, with State agencies, organizations, industries, and individuals. Before granting a pipeline right-of-way, the Regional Supervisor shall give consideration to any recommendation by the intergovernmental planning program, or similar process, for the assessment and management of OCS oil and gas transportation.

(b) Should the proposed route of a right-of-way adjoin and subsequently cross any State submerged lands, the applicant shall submit evidence to the Regional Supervisor that the State(s) so affected has reviewed the application. The applicant shall also submit any comment received as a result of that review. In the event of a State recommendation to relocate the proposed route, the Regional Supervisor may consult with the appropriate State officials.

(c)(1) The applicant shall submit photocopies of return receipts to the Regional Supervisor that indicate the date that each lessee or right-of-way holder referenced in § 250.160(c) of this part has received a copy of the application. Letters of no objection may be submitted in lieu of the return receipts.

(2) The Regional Supervisor shall not take final action on a right-of-way application until the Regional Supervisor is satisfied that each such lessee or right-of-way holder has been afforded at least 30 days from the date determined in paragraph (d)(1) of this section in which to submit comments.

(d) If a proposed right-of-way crosses any lands not subject to disposition by mineral leasing or restricted from oil and gas activities, it shall be rejected by the Regional Supervisor unless the Federal Agency with jurisdiction over such excluded or restricted area gives its consent to the granting of the right-of-way. In such case, the applicant, upon a request filed within 30 days after receipt of the notification of such rejection, shall be allowed an opportunity to eliminate the conflict.

(e)(1) If the application and other required information are found to be in compliance with applicable laws and regulations, the right-of-way may be granted. The Regional Supervisor may prescribe, as conditions to the right-of-way grant, stipulations necessary to protect human, marine, and coastal environments, life (including aquatic life), property, and mineral resources located on or adjacent to the right-of-way.

(2) If the Regional Supervisor determines that a change in the application should be made, the Regional Supervisor shall notify the applicant that an amended application shall be filed subject to stipulated changes. The Regional Supervisor shall determine whether the applicant shall deliver copies of the amended application to other parties for comment.

(3) A decision to reject an application shall be in writing and shall state the reasons for the rejection.

§ 250.162 Requirements for construction under a right-of-way grant.

(a) Failure to construct the associated right-of-way pipeline within 5 years of the date of the granting of a right-of-way shall cause the grant to expire.

(b)(1) A right-of-way holder shall ensure that the right-of-way pipeline is constructed in a manner that minimizes deviations from the right-of-way as granted.

(2) If, after constructing the right-of-way pipeline, it is determined that a deviation from the proposed right-of-way as granted has occurred, the right-of-way holder shall—

(i) Notify the operators of all leases and holders of all right-of-way grants in which a deviation has occurred, and within 60 days of the date of the acceptance by the Regional Supervisor

of the completion of pipeline construction report, provide the Regional Supervisor with evidence of such notification; and

(ii) Relinquish any unused portion of the right-of-way.

(3) Substantial deviation of a right-of-way pipeline as constructed from the proposed right-of-way as granted may be grounds for forfeiture of the right-of-way.

(c) If the Regional Supervisor determines that a significant change in conditions has occurred subsequent to the granting of a right-of-way but prior to the commencement of construction of the associated pipeline, the Regional Supervisor may suspend or temporarily prohibit the commencement of construction until the right-of-way grant is modified to the extent necessary to address the changed conditions.

§ 250.163 Assignment of a right-of-way grant.

(a) Assignment may be made of a right-of-way grant, in whole or of any lineal segment thereof, subject to the approval of the Regional Supervisor. An application for approval of an assignment of a right-of-way or of a lineal segment thereof, shall be filed in triplicate with the Regional Supervisor.

(b) Any application for approval for an assignment, in whole or in part, of any right, title, or interest in a right-of-way grant shall be accompanied by the same showing of qualifications of the assignees as is required of an applicant for a right-of-way in § 250.160 of this subpart and shall be supported by a statement that the assignee agrees to comply with and to be bound by the terms and conditions of the right-of-way grant. The assignee shall satisfy the bonding requirements in § 250.159(b) of this part. No transfer shall be recognized unless and until it is first approved, in writing, by the Regional Supervisor. A non refundable filing fee of $50 shall accompany the application for the approval of an assignment.

§ 250.164 Relinquishment of a right-of-way grant.

A right-of-way grant or a portion thereof may be surrendered by the holder by filing a written relinquishment in triplicate with the Regional Supervisor. It shall contain those items addressed in § 250.157(c) of this part. A relinquishment shall take effect on the date it is filed subject to the satisfaction of all outstanding debts, fees, or fines and the requirements in § 250.159(c)(9) of this part.

Subpart K—Production Rates

§ 250.170 Definitions for production rates.

Terms used in this subpart shall have meanings given below:

"Enhanced Recovery Operations" means pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations which alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

"Gas Reservoir" means a reservoir that contains hydrocarbons predominantly in a gaseous (single-phase) state.

"Gas-Well Completion" means a well completed in a gas reservoir or in the gas cap of an oil reservoir with an associated gas cap.

"Maximum Efficient Rate" (MER) means the maximum sustainable daily oil or gas withdrawal rate from a reservoir which will permit economic development and depletion of that reservoir without detriment to ultimate recovery.

"Maximum Production Rate" (MPR) means the approved maximum daily rate at which oil or gas may be produced from a specified oil-well or gas-well completion.

"Nonsensitive Reservoir" means a reservoir in which ultimate recovery is not decreased by high reservoir production rates.

"Oil Reservoir" means a reservoir that contains hydrocarbons predominantly in a liquid (single-phase) state.

"Oil Reservoir with an Associated Gas Cap" means a reservoir that contains hydrocarbons in both a liquid and gaseous (two-phase) state.

"Oil-Well Completion" means a well completed in an oil reservoir or in the oil accumulation of an oil reservoir with an associated gas cap.

"Sensitive Reservoir" means a reservoir in which ultimate recovery is decreased by high reservoir production rates. A high reservoir production rate is one which exceeds the MER.

"Waste of Oil and Gas" means: (1) The physical waste of oil and gas; (2) the inefficient, excessive, or improper use of, or the unnecessary dissipation of reservoir energy; (3) the locating, spacing, drilling, equipping, operating, or producing of any oil or gas well(s) in a manner which causes or tends to cause a reduction in the quantity of oil or gas ultimately recoverable from a pool under prudent and proper operations or which causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or (4) the inefficient storage of oil.

§ 250.171 General requirements and classification of reservoirs.

(a) Wells and reservoirs shall be produced at rates that will provide economic development and depletion of the hydrocarbon resources in a manner that would maximize the ultimate recovery without adversely affecting correlative rights.

(b) For directionally drilled wells in which the completed interval is closer than 500 feet from a unit or lease line or for vertically drilled wells in which the surface location is closer than 500 feet from a unit or lease line, for which the unit, lease, or royalty interests are not the same, the prior approval by the Regional Supervisor is required before production is commenced. An operator requesting such an approval shall furnish the Regional Supervisor with letters expressing acceptance or objection from operators of offset properties.

(c) The lessee shall propose a classification for each reservoir as an oil reservoir, an oil reservoir with an associated gas cap or a gas reservoir, and as sensitive or nonsensitive.

(d) All oil reservoirs with associated gas caps shall be initially classified as sensitive and shall require establishing a maximum efficient production rate and balancing of production in accordance with § 250.172(a) (1) and (5) of this part. All other oil reservoirs and all gas reservoirs shall be initially classified as nonsensitive.

(e) A reservoir may be reclassified by the Minerals Management Service (MMS) as to type and sensitivity at any time during its productive life when information becomes available showing that reclassification is warranted.

§ 250.172 Oil and gas production rates.

(a) *MER.* (1) The lessee shall propose an MER for each producing sensitive reservoir and submit Form MMS–1866, Request for Reservoir MER, with the appropriate supporting information to the Regional Supervisor for approval on or before December 1, 1988. Thereafter, the lessee shall determine an MER and submit Form MMS–1866 within 45 days of discovering that a reservoir is sensitive.

(2) The lessee may propose to revise an MER by submitting Form MMS–1866 with appropriate supporting information.

(3) The effective date of an MER for a reservoir or revision thereof shall be the first day of the month in which Form MMS–1866 is submitted.

(4) When approved, the MER shall not be exceeded, except as provided in paragraph (a)(5) of this section.

(5) If a reservoir is produced at a rate in excess of the MER for any month, the lessee should initiate measures necessary to balance production (offset overproduction by underproduction) during the next succeeding month. All overproduction shall be balanced by the end of the next succeeding calendar quarter following the quarter in which the overproduction occurred. Any operation in an overproduction status in any reservoir for two successive calendar quarters shall be shut in from that reservoir until the actual production is equal to that which would have occurred under the approved MER, unless an alternative plan is approved by the Regional Supervisor.

(6) The lessee shall review the MER for each producing sensitive reservoir at least once a year and submit Form MMS–1866 with appropriate supporting information.

(7) The lessee may request the reclassification of a reservoir from sensitive to nonsensitive and request approval for termination of an MER by submitting Form MMS–1866 with information supporting the reclassification and termination.

(8) At the request of the Regional Supervisor, the lessee shall furnish the information specified on Form MMS–1866 for any producing nonsensitive reservoir.

(b) *MPR.* (1) The lessee shall propose an MPR for each producing well completion together with full information on the method used in its determination. The MPR shall be based on well tests and any limitations imposed by well and surface equipment, sand production, gas-oil and water-oil ratios, location of perforated intervals, and prudent operating practices. The sum of the MPR's of wells completed in a sensitive reservoir shall not exceed the approved MER.

(2) The lessee shall conduct a well-flow potential test on all new, recompleted, and reworked well completions within 30 days of the date of first continuous production. Within 15 days after the end of the test period, the lessee shall submit a proposed MPR for the individual well completion on Form MMS–1867, Request for Well MPR, with the results of the well-flow potential test on Form MMS–1868, Well Potential Test Report. The initial MPR shall not exceed 110 percent of the test rate submitted and shall be effective on the first day of the month following the end of the test period if approved by the Regional Supervisor. During the 30-day period allowed for testing, the lessee may produce a new, recompleted, or reworked completion at rates necessary to establish the MPR. After the 30-day period and prior to approval of the initial MPR, a well completion may be produced at a rate not to exceed the proposed rate. The lessee shall report the total production obtained during the test period on Form 1868 and shall identify in the Remarks section of the form all wells completed in the reservoir.

(3) At least one well test shall be conducted during a calendar quarter for producing oil-well completions and results submitted on Form MMS–1869, Quarterly Oil Well Test Report, and conducted during a calendar half for producing gas-well completions and results submitted on Form MMS–1870, Semiannual Gas Well Test Report. Well tests shall be submitted within 45 days of the day the test was conducted.

(4) Unless otherwise ordered by the Regional Supervisor, a revised MPR shall automatically be approved for each well completion for each well test submitted equal to 110 percent of the test rate. The revised MPR will be effective on the first day of the month following the date the well test was conducted. Prior to the approval of a proposed increase of the MPR, a well completion may be produced at a rate not to exceed the proposed increased rate.

(5) When a well test is not submitted during a calendar quarter for an oil-well completion or during a calendar half for a gas-well completion, the MPR will be automatically cancelled effective on the first day of the appropriate following calendar period.

(6) When the results of a quarterly well test for an oil-well completion or a semiannual well test for a gas-well completion cannot be submitted within the specified time, the lessee shall request an extension of time for submitting those test results. The extension must be approved in advance by the Regional Supervisor to continue production under the last approved MPR.

(7) When approved by the Regional Supervisor, an MPR shall not be exceeded, except as provided in paragraphs (b)(4) and (c) of this section.

(c) *Temporary rates.* Temporary production rates resulting from normal variations and fluctuations exceeding a well MPR or reservoir MER shall not be considered a violation, provided that such production in excess of an approved MER is balanced by production in accordance with the provisions of paragraph (a)(5) of this section.

§ 250.173 Well production testing.

(a) The required well testing shall be conducted for a period of not less than four consecutive hours. Immediately prior to the 4-hour test period, the well completion shall have produced under stabilized conditions for a period of not less than six consecutive hours. The 6-hour pretest period shall not begin until after the recovery of a volume of fluid equivalent to the amount of fluids introduced into the formation during completion, recompletion, reworking, or treatment operations. Measured gas volumes shall be adjusted to the standard conditions of 14.73 pounds per square inch absolute (psia) (15.025 psia in the Gulf of Mexico OCS Region) and 60 °F for all tests. When orifice meters are used, a specific gravity for the gas shall be obtained or estimated, and a specific gravity-correction factor shall be applied to the orifice coefficient. The Regional Supervisor may require a prolonged test or retest of a well completion if the test is determined to be necessary for the establishment of a well MPR or a reservoir MER. The Regional Supervisor may approve test periods of less than 4 hours and pretest stabilization periods of less than 6 hours for well completions provided that test reliability can be demonstrated under such procedures.

(b) At the request of the Regional Supervisor, the lessee shall conduct a multipoint back-pressure test to determine the theoretical open-flow potential of a gas well. The test shall be conducted within 30 days of the Regional Supervisor's request or within the time period specified by the Regional Supervisor.

(c) An MMS representative may witness any well test of oil-well and gas-well completions. Upon request, a lessee shall provide advance notice to the Regional Supervisor of the time and date of well tests.

§ 250.174 Bottomhole pressure survey.

(a) For each new reservoir, the lessee shall conduct a static bottomhole pressure survey within 3 months after the date of first continuous production.

(b) For each producing reservoir with three or more producing completions, the lessee shall conduct annual static bottomhole pressure surveys in a sufficient number of key wells to establish an average reservoir pressure. The Regional Supervisor may require that a survey be performed on specific wells.

(c) The results of all static bottomhole pressure surveys obtained by the lessee shall be filed with the Regional Supervisor within 60 days after the date of the survey.

§ 250.175 Flaring and venting of gas.

(a) Oil-well and gas-well gas shall not be flared or vented without the approval of the Regional Supervisor except in the following situations:

(1) When gas vapors are flared or vented in small volumes from storage or other low-pressure production vessels and cannot be economically recovered.

(2) During temporary situations such as a compressor or other equipment failure or the relief of system pressures except the following:

(i) Oil-well gas shall not be flared or vented for more than 48 continuous hours without the approval of the Regional Supervisor. The Regional Supervisor may specify a limit of less than 48 hours when necessary to prevent degradation of the air quality. Flaring or venting gas from a facility shall not continue beyond a cumulative time of 144 hours during any calendar month without the approval of the Regional Supervisor.

(ii) Gas-well gas shall not be flared or vented beyond the time required to eliminate a temporary emergency without the approval of the Regional Supervisor.

(3) During the unloading or cleaning of a well, drill-stem testing, production-testing, or other well-evaluation testing for periods not to exceed 48 continuous hours unless a lesser period is specified by the Regional Supervisor to prevent degradation of the air quality.

(b) Except as provided in paragraph (a) of this section, oil-well gas shall not be flared or vented unless the flaring or venting will be for a period not exceeding 1 year and is approved by the Regional Supervisor in the following situations:

(1) The lessee has initiated an action which, when completed, will eliminate flaring and venting; or

(2) The lessee has submitted an evaluation supported by engineering, geologic, and economic data indicating that the oil and gas produced from the well(s) will not economically support the facilities necessary to save and/or sell the gas, or that sufficient quantities of gas are not available for marketing.

(c) Records detailing flaring or venting occurrences shall be maintained for each facility and shall be available for inspection by MMS representatives. These records shall include daily volumes of gas flared or vented, number of hours of flaring or venting on a daily basis, reasons for flaring or venting, and a list of producing wells contributing to the flaring and venting along with respective gas-oil ratio data. These records shall be maintained by the lessee for a minimum of 2 years at the lessee's field office nearest the Outer Continental Shelf facility or other locations conveniently available to the Regional Supervisor.

§ 250.176 Downhole commingling.

(a) An application to commingle hydrocarbons produced from multiple reservoirs within a common wellbore shall be submitted to the Regional Supervisor for approval and shall include all pertinent well information, geologic and reservoir engineering data, and a schematic diagram of well equipment. The application shall provide the estimated recoverable reserves as well as any available alternate drainage points which might be used to produce the reservoirs separately.

(b) For a competitive reservoir, notice of intent to submit the application shall be sent by the applicant to all other lessees having an interest in the reservoir prior to submitting the application to the Regional Supervisor.

(c) The application shall specify the well-completion number to be used for subsequent reporting purposes.

§ 250.177 Enhanced oil and gas recovery operations.

(a) The lessee shall timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles.

(b) A proposed plan for pressure maintenance, secondary and tertiary recovery, cycling, and similar recovery operations to increase the ultimate recovery of oil and/or gas from a reservoir shall be submitted to the Regional Supervisor for approval before such operations are initiated.

(c) Periodic reports of the volumes of oil, gas, or other substances injected, produced, or reproduced shall be submitted as required by the Regional Supervisor.

Subpart L—Production Measurement, Surface Commingling, and Security

§ 250.180 Measurement of liquid hydrocarbons.

(a) *General.* Measurement equipment shall be designed, installed, used, maintained, and tested so as to accurately and completely measure the liquid hydrocarbons produced on a lease for purposes of royalty determination. For purposes of this subpart, a liquid hydrocarbon is a mixture of hydrocarbons produced in liquid form after passing through surface separating facilities which is marketed or used as such.

(b) *Application and approval.* The lessee shall not commence production of liquid hydrocarbons unless the Regional Supervisor has approved an application for the measurement of liquid hydrocarbons and for commingling, if applicable. The application shall contain information sufficient to demonstrate that the requirements of this section will be met. Sales meter facilities shall be appropriately located with respect to the lease(s) and transportation system(s) involved.

(c) *Sales meter facility requirements.* (1) A meter upon which royalty is based shall be considered a sales meter.

(2) Sales meter facilities shall include the following components which shall be compatible with the systems to which they are connected:

(i) A positive-displacement or other meter approved by the Regional Supervisor. The meter shall be equipped with a nonreset totalizer.

(ii) A calibrated prover tank, a master meter, a mechanical displacement prover, or other device permanent or portable capable of proving the meter approved by the Regional Supervisor.

(iii) A proportional-to-flow sampling device which is pulsed by the meter output.

(iv) A temperature measurement or temperature compensation device.

(3) Sales meter facilities shall be designed to accomplish the following:

(i) Prevent reversal of flow through the meter;

(ii) Adequately protect meters subjected to pressure pulsation or surges by the use of surge tanks, expansion chambers, or similar devices;

(iii) Prevent the meter from being subjected to shock pressures which are greater than the maximum working pressure; and

(iv) Prevent bypassing of the meter.

(4) Sales meter facilities shall be maintained to ensure the following:

(i) Meters are operated within the gravity range specified by the manufacturer;

(ii) Meters are operated within the manufacturer's specifications for maximum and minimum flow rate for linear accuracy; and

(iii) Meters are reproven when changes in metering conditions affect the meters performance such as changes in pressure, temperature, density (water content), viscosity, pressure, and flow rate.

(5) The required sampling device shall conform to the following:

(i) The sampling device shall be installed such that the sampling point is in the flowstream immediately upstream

or downstream of the meter or divert valve,

(ii) The sample container for the sampling device shall be vapor-tight and include a mixing device to permit complete mixing of the sample prior to removal from the container, and

(iii) The sampling device is installed such that the sample probe is in the center of the flow piping in a vertical run and is located at least three pipe diameters downstream of any pipe fitting within a region of turbulent flow.

(6) When obtaining net standard volume and associated measurement parameters, the lessee shall use procedures and correction factors in accordance with the following chapters of the API Manual of Petroleum Measurement Standards (MPMS):

(i) Chapter 4, Proving Systems;

(ii) Chapter 5, Metering;

(iii)(A) Chapter 6.1, LACT System;

(B) Chapter 6.6, Pipeline Metering Systems;

(C) Chapter 6.7, Metering Viscous Hydrocarbons;

(iv)(A) Chapter 7.2, Dynamic Temperature Determination;

(B) Chapter 7.3, Static Temperature Determination Using Portable Electronic Thermometers;

(v) Chapter 8, Sampling;

(vi) Chapter 9, Density Determination;

(vii)(A) Chapter 10.1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method;

(B) Chapter 10.2, Determination of Water in Crude Oil by Distillation;

(C) Chapter 10.3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure);

(D) Chapter 10.4, (Publication 2542) Methods of Test for Water and Sediment in Crude Oils;

(viii)(A) Chapter 11.1, Volume 1, Table 5A—Generalized Crude Oils, Correction of Observed API Gravity to API Gravity at 60 °F and Table 6A—Generalized Crude Oils, Correction of Volume to 60 °F Against API Gravity at 60 °F;

(B) Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0–90 ° API Gravity Range;

(C) Chapter 11.2.2, Compressibility Factors for Hydrocarbons: 0.500–0.611 Relative Density Range (60 °F/60 °F) and -20 °F to 128 °F;

(ix) Chapter 12.2, Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters.

(7) All run tickets pulled and/or completed during a particular month shall be sent to the Regional Supervisor, within 15 days following the end of the month and shall clearly identify all observed data, all correction factors not included in the meter factor, the net standard volume, and all calculations and factors utilized.

(d) *Sales meter provings.* Sales meters for liquid hydrocarbons shall be proved and calibrated in accordance with the following requirements:

(1) The Minerals Management Service (MMS) representatives shall be permitted to witness regularly scheduled provings or any proving requested by the Regional Supervisor.

(2) The integrity of the calibration of each mechanical displacement prover, prover tank, master meter, or other type of prover shall be traceable to test measures which have been certified by the National Bureau of Standards.

(3) Master meters, mechanical-displacement provers, and prover tanks shall be calibrated in accordance with the following requirements:

(i) The master meter shall be calibrated to obtain a master meter factor before using the master meter to establish an operating meter factor. The master meter shall be calibrated with a fluid of similar gravity, viscosity, and temperature as flows through the operating meter and with a similar flow rate. This calibration shall be conducted monthly but the time between calibration shall not exceed 6 weeks unless a longer period of time is approved by the Regional Supervisor.

(ii) The lessee shall calibrate a master meter by conducting and recording runs until the results of two consecutive runs, if a prover tank is used, or five out of six consecutive runs, if a mechanical-displacement prover is used, produce results such that the greatest difference in the meter factors between the runs is not greater than 0.0002. The average of the two or the five runs which produced the acceptable results shall be used to compute the master meter factor.

(iii) The master meter may be installed either upstream or downstream of the operating meter but shall be upstream of any back-pressure or reverse flow check valves associated with the operating meter.

(iv) Mechanical-displacement provers and prover tanks shall be calibrated at least every 5 years in accordance with the API MPMS, Chapters 4 and 11.2.3. A copy of each calibration report shall be submitted to the Regional Supervisor within 15 days following calibration.

(v) When calibrating meters with a mechanical-displacement prover, prover tank, or master meter, the following appropriate correction factors shall be taken into account:

(A) The change in prover volume due to pressure in the steel pipe (Cps) using API MPMS, Chapter 12, Section 2, Appendix A, Table A–3, Pressure Correction Factors for Steel, Cps;

(B) The change in volume of the test liquid with the change in temperature (Ctl) using API MPMS, Chapter 11.1, Volume I, Table 6A, Generalized Crude Oils Correction of Volume to 60 °F Against API Gravity at 60 °F;

(C) The change in prover volume due to the change in temperature (Cts) using API MPMS, Chapter 12, Section 2, Appendix A, Table A–1, Temperature Correction Factors of Mild Steel, and Table A–2, Temperature Correction Factors for Stainless Steel; and

(D) The change in volume of the test liquid with the change in pressure (Cpl) using Chapter 11.2.1 or 11.2.2, API MPMS, as appropriate.

(4) Each operating sales meter shall be proved to determine the meter factor each month, however, the time between meter factor determinations is not to exceed 42 days. Meter provings shall be in accordance with the following:

(i) When establishing an operating meter factor with a prover tank, proof runs shall be made and recorded until two consecutive runs produce results such that the difference between results is not greater than .05 percent of the prover tank volume. The average of the results of these two runs shall be used to compute the meter factor.

(ii) When establishing an operating meter factor with a master meter, proof runs shall be made until three consecutive runs produce results such that the difference in the meter factor between all runs is not greater than 0.0005. The volume of each of these runs shall be at least 10 percent of the hourly rated capacity of the operating meter and shall be of sufficient amount for the determination of an accurate operating meter factor. The average of the results of these three runs shall be used to compute the meter factor.

(iii) When establishing an operating meter factor with a mechanical-displacement prover, proof runs shall be made and recorded until five out of six consecutive runs produce results such that the difference between results is not greater than 0.0005. The average of the results of the five runs shall be used to compute the meter factor.

(5) The lessee shall submit copies of all meter proving reports for sales meters and master meters to the Regional Supervisor monthly within 15 days following the end of the month. Meter factors which are determined to be in tolerance shall be applied from the date of proving.

(i) A meter factor is considered a malfunction factor when the deviation between the factor and the previous factor exceeds 0.0025. In the event of such a malfunction, the meter shall be

immediately removed from service, checked for damage or wear, adjusted and/or repaired, and reproven prior to return to service. The arithmetic average of the malfunction factor and the previous factor shall be applied to the production measured through the meter between the date of the previous factor and the date of the malfunction factor. Malfunction meter factors shall be clearly indicated on the proving report which shall also contain all appropriate remarks regarding subsequent repairs and/or adjustments.

(ii) When a malfunction results in the failure of the meter to register production, the meter shall be immediately removed from service, repaired, and reproven prior to returning it to service. The previous meter factor shall be applied to the production run between the date of that factor and the date of the failure. Any unregistered production shall be estimated by the best possible means and shall be reported as estimated production.

(iii) When the results of a sales meter proving exceed the repeatability (run tolerance) criteria and all measures excluding the adjustment and/or repair of the meter and meter components cannot bring results to within tolerance (failure to obtain repeatability of runs), a factor shall be established using proving results made prior to any adjustment and/or repair of the meter and meter components. The established factor shall be considered a malfunction factor and treated in accordance with paragraph (d)(5)(i) of this section.

(6) To correct gross volumes metered under nonstandard conditions (standard conditions are 0 pounds per square inch gauge (psig) and 60 °F), Cpl factors shall be calculated into the meter factor or listed on the appropriate run ticket. The Ctl factors shall be listed on the appropriate run ticket when the meter is not automatically temperature compensated.

(7) Run tickets shall be pulled at the time of any proving which is conducted for the purpose of establishing a monthly meter factor or which results in the establishment of a malfunction meter factor. A copy of the subject run ticket shall be submitted in accordance with § 250.180(c)(7) of this part.

(e) *Allocation meter facility requirements.* (1) For purposes of this subpart, an allocation meter is a meter whose volume measurement is used to substantiate which portion of the volume measured by a royalty meter is attributable to a particular lease, measurement point, or well. Allocation meter facilities shall include a meter, provisions for use of a device capable of proving the allocation meter, and equipment for continuous or daily sampling. Samples shall be taken continuously or daily.

(2)(i) Allocation meters measuring 50 barrels of oil per day or more shall be proven monthly, and

(ii) Allocation meters measuring less than 50 barrels of oil per day shall be proven quarterly.

(3) A copy of allocation meter proving reports must be kept at the field location for a period of 2 years.

(4) If an allocation meter proving results in a meter factor which differs from the previous meter factor by an amount greater than 0.02 and less than 0.07, the allocation meter shall be adjusted and reproven prior to return to service.

(5) If an allocation meter proving results in a meter factor which differs from the previous meter factor by an amount equal to or greater than 0.07, the allocation meter shall be repaired and reproven prior to return to service.

(f) *Sales tank requirements.* (1) Sales tank facilities designated by the Regional Supervisor as a sales location on which royalty shall be equipped with a vapor-tight thief hatch and vent-line valve and a fill line designed to minimize free fall and splashing.

(2) A complete set of calibration charts (tank tables) shall be submitted to the Regional Supervisor prior to use of the tank for sales measurement purposes. The volume and other measurement parameters of the liquid production in sales tanks shall be obtained using correction factors and procedures in accordance with the following chapters of API MPMS:

(i) Chapter 2, Tank Calibration (including Standards 2550, 2551, 2552, 2555, and 2556).

(ii) Chapter 3, Tank Gauging (Standard 2545);

(iii)(A) Chapter 7.2, Dynamic Temperature Determination;

(B) Chapter 7.3, Static Temperature Determination Using Portable Electronic Thermometers;

(iv) Chapter 8, Sampling;

(v) Chapter 9, Density Determination;

(vi)(A) Chapter 10.1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method;

(B) Chapter 10.2, Determination of Water in Crude Oil by Distillation;

(C) Chapter 10.3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure);

(D) Chapter 10.4, (Publication 2542) Methods of Test for Water and Sediment in Crude Oils;

(vii) Chapter 11.1, Volume 1, Table 5A, Generalized Crude Oils Correction of Observed API Gravity to API Gravity at 60 °F, and Table 6A, Generalized Crude Oils Correction of Volume to 60 °F, Against API Gravity at 60 °F.

(3) A copy of each completed run ticket written from tank gaugings shall be submitted to the Regional Supervisor within 15 days of the run ticket being written.

§ 250.181 Measurement of gas.

(a) *General.* The lessee shall maintain all gas sales or allocation meters designated by the Regional Supervisor in accordance with the requirements of this section.

(b) *Applications and approvals.* The lessee shall not commence production of gas hydrocarbons unless the Regional Supervisor has approved an application for measurement of gas production. The application shall be submitted to the Regional Supervisor for approval and shall contain information sufficient to demonstrate that the requirements of this section will be met.

(c) *Gas meter requirements.* (1) The measuring equipment shall be installed and operated in accordance with the recommendations contained in the API MPMS, Chapter 14, Natural Gas Fluids Measurement.

(2) The unit of volume for gas measurement shall be 1 cubic foot at a base temperature of 60 °F and at a base pressure of 15.025 pounds per square inch absolute (psia) (14.73 psia for Pacific OCS Region), and the measurement unit shall be 1,000 cubic feet (Mcf) of gas.

(3) Gas meters shall be operated in accordance with the following requirements:

(i) The Minerals Management Service representatives shall be permitted to witness regularly scheduled calibrations and any calibration requested by the Regional Supervisor.

(ii) The integrity of the calibration equipment shall be in accordance with the standards in paragraph (c)(1) of this section.

(iii) Each gas meter shall be calibrated at reasonable intervals not to exceed 45 days. For positive displacement or turbine meters, the calibration shall be conducted at the average hourly rate of flow since the last calibration. For orifice meter installations, the differential range and static range shall be consistent with the hourly flow rate. The lessee shall retain calibration test data at the field location for a period of 2 years.

(iv) Whenever a meter is not functioning or not registering within the limits of accuracy prescribed by the manufacturer, it shall be immediately removed from service and not returned

to service until repaired or adjusted to read accurately.

(v) During calibration, if readings of static and differential pressure are found to be within contractual tolerances with respect to test device readings, previous meter readings shall be considered correct in computing deliveries of gas since the previous calibration. If the readings are greater than contractural tolerances, the volume measured since the last calibration shall be corrected as follows:

(A) If the time the error occurred is ascertainable, the volume adjustment shall be calculated for that period of time. No retroactive adjustment of volumes metered for allocation beyond a 23-day period is required.

(B) If the time the error occurred is not ascertainable, the volume adjustment shall be applied to one-half of the time elapsed since the last date of calibration or 23 days, whichever is less.

§ 250.182 Surface commingling of production.

(a) *General requirements.* For purposes of this subpart, surface commingling is the surface mixing of production from two or more leases prior to measurement for royalty purposes. The commingling of production from different leases prior to measurement for royalty sales determination shall be in accordance with this section.

(b) *Applications and approvals.* (1) The lessee shall not commence commingling of production unless the Regional Supervisor has approved the commingling and the method of measurement. The lessee shall submit an application for commingling to the Regional Supervisor for approval, and the application shall contain appropriate information regarding the method of allocation measurement, processing, if applicable, and the manner of entry into the particular commingling system.

(2) All allocation methods and procedures and changes thereto shall be approved by the Regional Supervisor.

(c) *Well tests.* The lessee shall conduct a well test for allocation purposes at least once every 2 months or other period of time as determined by the Regional Supervisor and shall retain test data at the field location for a period of 2 years. These tests are to be conducted in accordance with procedures outlined in § 250.173 of this part and can be used when submitting well tests as required in § 250.173.

§ 250.183 Site security.

All locations where oil, gas, or both are measured shall be operated and maintained to ensure against the loss or theft of production and to assure accurate measurement for royalty purposes. Production, transportation to shore, and sales activities shall comply with the following requirements:

(a) The components of sales measuring devices (metering units and tanks) shall be sealed in a manner to preclude tampering. Wire or other acceptable types of seals shall be numbered and recorded. The list of seal numbers and the installation location shall be maintained at the field location and be available for inspection by MMS representatives.

(1) The following metering and sampling unit components shall be sealed in such a manner that the component cannot be opened, closed, or altered in any way without destroying the seal:

(i) All meter stack component connections from the base of the stack to the register;

(ii) Sampling system including packing device, fittings, chains, sight glass, and container lid;

(iii) Components of the temperature and gravity compensation device;

(iv) Additional components as required by the Regional Supervisor;

(2) All valves on lines leaving an oil storage tank including load-out line valves, drain-line valves, and connection-line valves between sale and nonsale tanks shall be sealed in such a manner that the valve is closed and cannot be opened without destroying the seal.

(b) Each storage tank (sales or inventory) used in the royalty determination process shall be clearly identified by a sign that contains the name of the facility operator, the size of the tank, and the tank number.

(c) No one shall bypass MMS-approved royalty sales meters and sales tanks.

(d) Evidence of theft or mishandling of production from an offshore lease, or of tampering or bypassing with metering or proving devices, or of falsifying any measurement of production from an offshore lease shall be reported to the Regional Supervisor as soon as possible but not later than the next business day after discovery of evidence of theft or mishandling.

Subpart M—Unitization

§ 250.190 Authority and requirements for unitization.

(a) Unitization may be approved or required by the Regional Supervisor for the prevention of waste, the conservation of the natural resources of the Outer Continental Shelf (OCS), or for the protection of correlative rights therein, including the protection of Federal royalty interests. Lessees may agree among themselves to unitization, subject to the Regional Supervisor's approval (voluntary unitization), or the Regional Supervisor may require unitization on the initiative of one or more lessees or on the Regional Supervisor's own initiative (compulsory unitization).

(b) Unitized operations may be approved when the Regional Supervisor has determined that such action will expedite and promote exploration and development efforts. Unitized operations may also be approved or required by the Regional Supervisor when a reservoir has been determined to be reasonably delineated and productive and such action is found to be necessary for the prevention of waste, conservation of natural resources of the OCS, or for the protection of correlative rights.

(c) A unit area shall include the minimum number of leases or portions of leases required to permit one or more mineral reservoirs or potential hydrocarbon accumulations to be served by a minimum number of platforms, facility installations, and wells necessary for the efficient exploration for or development and production of oil and gas.

(d) A unit agreement shall provide for the appointment of a unit operator and the allocation of benefits to the unitized leases. The unit operator and the owners of working-interests shall enter into a unit operating agreement which shall describe how all costs and liabilities incurred in maintaining or conducting operations pursuant to the unit agreement shall be apportioned. In units involving one or more net-profit-share leases, the unit operating agreement shall be approved by the Regional Supervisor as to the way that costs and credits are attributable to the net-profit-share leases.

(e) Upon the expiration or termination of a unit agreement, or when there is an adjustment of a unit area that results in the elimination of a lease from the unit agreement, each lease that was but is no longer subject in whole or in part to the unit agreement shall expire unless—

(1) Its initial term has not expired,

(2) Drilling, production, or well-reworking operations are being conducted thereon in accordance with applicable regulations, or

(3) A suspension of production or operations has been ordered or approved for the excluded lease.

(f) Drilling, production, and well-reworking operations performed in accordance with a unit agreement shall be deemed to be performed for the

benefit of all leases that are subject in whole or in part to the unit agreement. Plans may provide for the cessation of actual drilling activities for a reasonable period between the discovery and delineation of one or more reservoirs and the initiation of actual development and production operations. When plans that call for the cessation of drilling prior to actual production involve one or more leases beyond their primary term, the plans shall be accompanied by a request and supporting justification for a suspension of production pursuant to § 250.10 of this part.

(g) A unit agreement shall be effective on the date specified in the unit agreement and shall terminate when unitized substances are no longer being produced from the unit area and drilling or well-workover operations are no longer being conducted under the unit agreement, unless the Director has ordered or approved a suspension of production pursuant to § 250.10 of this part.

(h) If a lease is subject in whole or in part to unitization, the entire lease shall continue in force for the term provided in the lease and as long thereafter as any portion of the lease remains part of the unit area, and as long as there are operations which serve to continue the unit in effect.

(i) When a lease that is subject in whole or in part to a unit agreement is beyond the initial fixed term of the lease and unitized substances are not being produced, the lease shall expire unless—

(1) The unit operator conducts a continuous drilling or well reworking program designed to develop or restore the production of unitized substances, or

(2) A suspension of operations has been ordered or approved in accordance with § 250.10 of this part.

§ 250.191 Competitive reservoir operations.

(a) The Regional Supervisor may require development and production operations in a competitive reservoir (i.e., a reservoir in which there are one or more producing or producible well completions on each of two or more leases, or portions thereof, in which the lease operating interests are not the same), to be conducted under either a voluntary joint Development and Production Plan or unitization agreement. For purposes of this paragraph, a producible well completion is a well which is capable of production and which is shut in at the wellhead or at the surface but not necessarily connected to production facilities, and from which the operator plans future production.

(b) Lessees may request at any time that the Regional Supervisor make a preliminary determination as to whether a reservoir is competitive. The Regional Supervisor shall notify the lessees upon making such determination. The lessees, within 30 days of such notice or such time as approved by the Regional Supervisor, shall advise the Regional Supervisor of their concurrence or submit an objection with supporting evidence. The Regional Supervisor will make a final determination and notify the lessees.

(c) When drilling or production operations are conducted in a competitive reservoir, the lessees, on their own initiative or at the direction of the Regional Supervisor, shall submit a joint plan for approval governing the applicable operations. The joint plan shall be submitted within 90 days after the final determination by the Regional Supervisor that the reservoir is competitive and shall provide for the development and/or production of the reservoir and may provide for the submittal of supplemental plans for approval by the Regional Supervisor. If agreement on a joint Development and Production Plan cannot be reached by the lessees within the approved period of time, each lessee shall submit a separate plan. If the differences in the separate plans are not resolved at a subsequent hearing and the Regional Supervisor determines that unitization is necessary pursuant to § 250.190(b) of this subpart, steps to require unitization will be initiated pursuant to § 250.193 of this part.

§ 250.192 Voluntary unitization.

(a) Lessees who seek approval of unitization shall file a request with the Regional Supervisor accompanied by a draft of the proposed unit agreement; a proposed initial plan of operation supporting geological, geophysical, and engineering data; and any other information that may be necessary to show that the unitization proposal meets the criteria of § 250.190 of this part.

(b) The proposed unit agreement shall conform to the appropriate Model Unit Agreement (MUA) in § 250.194 of this part. For good cause, the Regional Supervisor may require or upon request approve variations from the MUA. Any request for variation shall be made at the time the proposed unit agreement is submitted to the Regional Supervisor.

(c) After the Regional Supervisor approves the unitization proposal, lessees shall execute the unit agreement and file with the Regional Supervisor for approval such copies of the unit agreement, unit operating agreement, and the initial plan of operation as the Regional Supervisor may require.

§ 250.193 Compulsory unitization.

(a) If it is determined by the Regional Supervisor that unitization of operations within a proposed unit area is necessary for the prevention of waste, conservation of the natural resources of the OCS, or the protection of correlative rights therein, unitization shall be imposed according to a unitization plan. This plan shall conform to the appropriate MUA form in § 250.194 of this part, unless variations from the model agreement have been approved for good cause by the Regional Supervisor.

(b)(1) Lessees who seek compulsory unitization shall file a request with the Regional Supervisor accompanied by a proposed unit agreement as described in § 250.193(a) of this part, a proposed unit operating agreement, and a proposed initial plan of operation together with supporting geological, geophysical, and engineering data, and any other information that may be necessary to show that unitization meets the criteria of § 250.190 of this part. The proposed unit agreement shall include a counterpart executed by each lessee seeking compulsory unitization. Lessees seeking compulsory unitization shall simultaneously serve copies of the request, the proposed unit agreement with executed counterparts, the proposed unit operating agreement, and the proposed initial plan of operation on the nonconsenting lessees.

(2) If the Regional Supervisor initiates compulsory unitization, all lessees of the proposed unit area shall be served with a copy of the unitization plan and a statement of reasons for the proposed unitization.

(c)(1) The Regional Supervisor may not require compulsory unitization until all lessees of the proposed unit area are provided reasonable notice and an opportunity for a hearing. Any lessee owning an interest in the proposed unit area may request a hearing within 30 days of service of notice by the Regional Supervisor or service of a request for compulsory unitization by a lessee.

(2) No hearing may be held pursuant to this paragraph until at least 30 days after written notice have been provided to all parties owning interests which would be made subject to the unit agreement. The Regional Supervisor shall afford all lessees of the proposed unit area an opportunity to submit views orally and in writing and to question both those seeking and those opposing compulsory unitization. Adjudicatory procedures are not required, but the

decision of the Regional Supervisor shall be based upon a record of the hearing including any written information made a part of the record. The Regional Supervisor will cause a verbatim transcript to be made by a court reporter, the cost of which will be borne by the party seeking compulsory unitization. Three copies of the transcript shall be provided to the Regional Supervisor without charge within 10 days after the hearing.

(d) The Regional Supervisor may issue an order(s) that requires or disapproves compulsory unitization. Any such order shall include a statement of reasons for the action taken including identification of those parts of the record which form the basis of the decision. The final order of the Regional Supervisor may be appealed in accordance with 30 CFR Part 290.

§ 250.194 Model unit agreements.

(a) *Model unit agreement for exploration, development, and production units.*

UNIT AGREEMENT FOR OUTER CONTINENTAL SHELF EXPLORATION, DEVELOPMENT, AND PRODUCTION OPERATIONS ON THE ——— UNIT BLOCKS ———, ——— AREA OFFSHORE ———
CONTRACT NO. ———

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Witnesseth:

WHEREAS, section 5(a) of the Act authorizes the Secretary of the Interior (Secretary) to prescribe rules and regulations which shall provide for unitization, pooling, and drilling agreements;

WHEREAS, pursuant to the rules and regulations of the Secretary, 30 CFR 250.190, *et seq.*, it is deemed to be in the interest of conservation, prevention of waste, or the protection of correlative rights to unitize the oil and gas interest in the unit area; and

WHEREAS, it is deemed to be necessary in the interest of conservation, for the prevention of waste, or for the protection of correlative rights to conduct exploration, development, and production operations in the unit area as though the area were subject to a single lease;

NOW, THEREFORE, in consideration of the premises and promises contained herein, it is agreed that:

Article I—*Definitions*

The following definitions of terms shall apply to this Agreement:

"Act" means the OCS Lands Act of 1953, as amended, 43 U.S.C. 1331, *et seq.*

"Agreement" means this unit agreement, approved by the Regional Supervisor for conducting exploration, development, and production operations within the unit area.

"Block" means an area designated as a block on a U.S. Official Leasing Protraction Diagram for an area of the OCS.

"Participating area" is that part of the unit area that is reasonably proven by drilling and completion of producible wells, geological and geophysical information, and engineering data to be capable of producing hydrocarbons in paying quantities.

"Paying quantities" as used herein means the production of oil and/or gas in quantities sufficient to yield a return in excess of operating costs.

"Regional Supervisor" means the Regional Supervisor of the MMS, Department of the Interior (DOI), or a designee, authorized and empowered to regulate and approve unit operations.

"Regulations" means all rules prescribed or adopted pursuant to the Act. They include all regulations prescribed or amended at any time to provide for the prevention of waste, conservation of natural resources of the OCS, and the protection of correlative rights therein.

"Reservoir" means an underground porous, permeable medium containing an accumulation of oil or gas or both. Each zone of a general structure containing such an accumulation that is separated from any other accumulation of oil or gas or both in the structure is a separate "reservoir."

"Unit area" means the area of the OCS which is made subject to this Agreement and described in Article III.

"Unit operating agreement" means an agreement made between the working-interest owners and the unit operator providing for the apportionment of costs and liabilities incurred in conducting operations pursuant to this Agreement and the establishment of such other rights and obligations as they deem appropriate.

"Unit operator" means the person, association, partnership, corporation, or other business entity designated by the working-interest owners and approved by the Regional Supervisor to conduct unit operations within the unit area in accordance with plans of operation approved pursuant to the Act, applicable regulations, and this Agreement.

"Unitized substances" means oil and/or gas within the reservoir(s) that underlie the unitized lands and which are recovered or produced by operations pursuant to this Agreement.

"Working interest" means an interest in the unit area held by virtue of a lease, operating agreement, or other contractual arrangement under which, except as otherwise provided in this Agreement, the rights or authority to explore for, develop, and produce oil and gas are conferred. The right delegated to the unit operator by this Agreement is not a working interest.

"Working-interest owner" means a party to this agreement that owns a working interest.

Article II—*Incorporation*

All provisions of the Act, the regulations, other applicable laws, and the leases covering OCS lands within the unit area are made part of this Agreement.

Article III—*Unit area and exhibits*

3.1 The following described offshore area as shown on the U.S. Official Leasing Protraction Diagram is subject to valid leases and constitutes the unit area.

3.2 Exhibit "A", which is attached to this Agreement and made a part hereof, is a plat identifying the unit area and component blocks and leases.

3.3 Exhibit "B", which is attached to this Agreement and made a part hereof, is a schedule listing the component leases and the ownership of each.

3.4 Exhibit "C", which will be submitted in accordance with the provisions of this Agreement and will be made a part hereof, is a schedule listing the component parts of the participating area(s) by lease and the percentage of oil or gas, or both, that is to be allocated to each lease.

3.5 Exhibits "A", "B", and "C" shall be revised by the unit operator whenever changes in the unit area, changes in the participating area, changes in the ownership of one or more leases, or changes in the percentages of oil or gas, or both, allocated to the individual leases render such changes necessary. Four copies of the revised exhibits shall be submitted to the Regional Supervisor for approval.

Article IV—*Designation of unit operator*

4.1 ——— is designated as the unit operator and agrees to accept the rights and obligations of the unit operator to explore for, develop, and produce oil and/or gas as provided in this Agreement.

4.2 Except as otherwise provided in this Agreement and subject to the terms and conditions of approved plans of operations, the exclusive rights and obligations of the owners of working-interests to conduct unit operations to explore for, develop, and produce oil and/or gas in the unit area are delegated to and shall be exercised by the unit operator. This delegation neither relieves a lessee of the obligation to comply with all lease terms nor transfers title to any lease or operating agreement.

Article V--*Resignation or removal of unit operator*

5.1 The unit operator shall have the right to resign at any time. Such resignation shall not become effective until 60 days after written notice of an intention to resign has been delivered by the unit operator to the working-interest owners and the Regional Supervisor and until all platforms, artificial

islands, installations, and other devices, including wells used for conducting operations in the unit area, are placed in a condition satisfactory to the Regional Supervisor for the transfer of operations, or, if no successor unit operator has been designated, for suspension or abandonment of operations. If a successor unit operator is designated and approved as provided in Article VI, the resignation shall be effective upon the designation and approval of the successor unit operator.

5.2 The unit operator may be subject to removal by the same percentage vote of the owners of working-interests as provided by Article VI for the designation of a successor unit operator. This removal shall not be effective until the working-interest owners notify the Regional Supervisor and the unit operator and until the Regional Supervisor approves the designation of a successor unit operator.

5.3 The resignation or removal of the unit operator shall not release the unit operator from liability for any failure to meet any obligations which accrued before the effective date of resignation or removal.

5.4 The resignation or removal of the unit operator shall not terminate any right, title, or interest as the owner of a working-interest or other interest in the unit area. However, when the resignation or removal of the unit operator becomes effective, the unit operator shall relinquish to the successor unit operator all wells, platforms, artificial islands, installations, devices, records, and any other assets all owned solely by the unit joint account.

Article VI—*Successor unit operator*

6.1 Whenever the unit operator tenders its resignation as unit operator or is removed as provided in Article V, a successor unit operator may be designated by (a) an affirmative vote of the owner(s) of a majority of the working-interests, based on (1) their respective shares of the acreage subject to this Agreement; (2) their respective estimated volume of oil or gas, or both, originally in place; or (3) their decision pursuant to the unit operating agreements, and (b) the successor unit operator's acceptance in writing of the rights and obligations of the unit operator. The successor unit operator shall file with the Regional Supervisor four executed copies of the designation of successor. However, the designation shall not become effective until approved by the Regional Supervisor.

6.2 If no successor unit operator is designated as herein provided within 60 days following notice to the Regional Supervisor of the unit operator's intent to resign or removal of a unit operator, the Regional Supervisor may elect to designate one of the working-interest owners other than the unit operator as successor unit operator or may declare this Agreement terminated.

Article VII—*Unit operating agreement*

7.1 The owners of working-interests and the unit operator shall enter into a unit operating agreement which shall describe how all costs and liabilities incurred in maintaining or conducting operations pursuant to this Agreement shall be apportioned and assumed. The unit operating agreement shall also describe how the benefits which may accrue from operations conducted on the unit area shall be apportioned.

7.2 The owners of working-interests and the unit operator may establish by means of one or more unit operating agreements such other rights and obligations as they deem necessary or appropriate. However, no provision of the unit operating agreement shall be deemed to modify the terms and conditions of this Agreement or to relieve the working-interest owners or the unit operator of any obligation set forth in this Agreement. In case of any inconsistency or conflict between this Agreement and the unit operating agreement, the terms of this Agreement shall prevail.

7.3 Three copies of the unit operating agreement executed in conjunction with the first section of this Article shall be attached to this Agreement when it is filed with the Regional Supervisor with a request for approval. Three copies of all other unit operating agreements and any amendments thereto also shall be filed with the Regional Supervisor within 30 days of final execution.

Article VIII—*Appearances and notices*

8.1 The unit operator shall, after notice to other parties affected, have the right to appear on behalf of all working-interest owners before the DOI or any other body legally empowered to issue decisions concerning orders or regulations of the DOI and to appeal from these decisions. The expense of these appearances shall be paid and apportioned as provided in the unit operating agreement. However, any affected working-interest owners shall have the right at their own expense to be heard in any proceeding.

8.2 Any order or notice relating to this Agreement which is given to the unit operator by the Regional Supervisor shall be deemed given to all working-interest owners of the unit area. All notices required by this Agreement to be given to the unit operator or the owners of working-interests shall be deemed properly given if given in writing and delivered personally or sent by prepaid registered or certified mail to the addresses set forth below or to such other addresses as may have been furnished in writing to the party sending the notice.

Article IX—*Plan of operation*

9.1 The unit operator shall submit plans of operation which are consistent with the requirements for Exploration Plans or Development and Production Plans as required by the Act, Subpart B of 30 CFR Part 250, and other sections of the regulations. All operations within the unit area shall be conducted in accordance with an approved plan.

9.2 When no oil or gas is being produced in paying quantities from the unit area and when all or part of the area is subject to one or more leases beyond the primary term, a continuous drilling or well-reworking program shall be maintained with lapses of no more than 90 days per lapse between such operations unless a suspension of production or other operation has been ordered or approved by the Regional Supervisor or unless extended by the Director pursuant to 30 CFR 250.13(b). Plans may call for a cessation of drilling operations for a reasonable period of time after the discovery and delineation of a reservoir when such a pause in drilling activities is warranted to permit the design, fabrication, and erection of platforms and other installations needed for development and production operations, provided a suspension of production or other operation has been ordered or approved by the Regional Supervisor.

9.3 An acceptable initial plan of operation shall be submitted at the time this Agreement is filed for the Regional Supervisor's approval. Each plan of operation shall expire on the date specified in the plan. At least 60 days before the scheduled expiration of any plan, unless the Regional Supervisor grants an extension for good cause, the unit operator shall file an acceptable subsequent plan of operation or approval in accordance with this Article.

Article X—*Revision of unit area*

10.1 The unit area may be further revised by additions necessary for unit operations or for the inclusion of an area capable of producing oil and/or gas in paying quantities whenever such action appears proper to include additional lands or may be further revised by the contraction of the unit area when such contraction is necessary or advisable to conform with the purposes of this Agreement. Such additions or contractions shall be effected by the unit operator on its own motion after preliminary concurrence of the Regional Supervisor or on demand of the Regional Supervisor. The effective date of any expansion or contraction of the unit area shall be the first of the month following the date of approval of the expansion or contraction by the Regional Supervisor provided, however, that a more appropriate effective date may be used if justified by the unit operator and approved by the Regional Supervisor.

10.2 The unit area shall not be reduced on account of the depletion of the unitized substances for which it was established, but the unit area established under the provisions of this article shall terminate automatically whenever operations are permanently abandoned in the unit.

Article XI—*Participating areas*

11.1 Prior to commencement of production of unitized substances, or as soon thereafter as required by the Regional Supervisor, the unit operator shall submit to the Regional Supervisor, as Exhibit "C," a schedule by lease of (a) all land reasonably proven to be productive of unitized substances in paying quantities by the drilling and completion of producible wells, geological and geophysical information, and engineering data, and (b) the percentage of unitized substances to be allocated as provided in Article XII to each lease. All lands in said schedule, upon approval thereof by the Regional Supervisor, shall constitute the initial participating area, effective as of the date such production commences. The participating area shall be described in parcels no smaller than ¼ x ¼ x ¼ blocks.

11.2 Subject to approval of the Regional Supervisor, the participating area(s) so

established shall be revised from time to time to include additional land reasonably proven to be productive in the same manner as provided in section 11.1 of this Article, or lands proven not to be productive to be excluded in the same manner, and Exhibit "C" shall be revised accordingly. The effective date of any revision shall be the first of the month in which the information is obtained which provides the basis for the approval of the revision by the Regional Supervisor provided, however, that a more appropriate effective date may be used if justified by the unit operator and approved by the Regional Supervisor. No land shall be excluded from the participating area(s) on account of depletion of the unitized substances.

11.3 A separate participating area may be established for each accumulation of unitized substances or for any group thereof which is produced as a single pool or zone and any two or more participating areas so established may be combined into one, all subject to approval of the Regional Supervisor.

11.4 Nothing herein contained shall be construed as requiring any retroactive adjustment for production obtained prior to the effective date of the revision of the participating area.

Article XII—*Allocation of production*

12.1 The unit operator shall pay all production royalties and make deliveries of oil and gas which are payments of royalties taken-in-kind or which, pursuant to the Act, are purchased by the United States. Unitized substances shall be allocated within the participating area(s) on (a) a volumetric basis of oil and gas in place under original reservoir conditions, or (b) a surface area basis, and proportionally credited to the respective leases committed hereto. The unit operator shall furnish the Regional Supervisor geological and engineering maps and data sufficient to support the net-acre feet determination for volumetric allocation between leases. Oil and gas produced from the unit area prior to the effective date of this Agreement shall not be allocated under this Agreement. The royalty payments under leases subject hereto shall be based and calculated upon the production allocated to the leases as specifically provided herein. The oil and gas saved, removed, or sold from a unit area shall be allocated in this manner, regardless of where any well is drilled and produced in the unit area.

12.2 For the purpose of determining royalty obligations, unitized substances on which royalty has been paid and which are used for repressuring, stimulation of production, or increasing ultimate recovery from the unit area, in conformity with an approved plan of operation, may be deemed to be a portion of the gas and liquid-hydrocarbon substances subsequently saved, removed, or sold from the unit area. In such instances, a like amount of gas and liquid-hydrocarbon substances similar to that previously used may be saved, removed, or sold from the unit area without paying a royalty thereon. However, as to dry gas, only dry gas and not products extracted therefrom may be saved, removed, or sold royalty free. The royalty-free withdrawal shall be accomplished in accordance with an approved plan of operation and the amounts of gas and liquid-hydrocarbon substances withdrawn that are to be recognized as free of royalty charges shall be computed in accordance with a formula approved or prescribed by the Regional Supervisor. Any withdrawal of royalty-free gas or liquid-hydrocarbon substances shall terminate upon the termination of this Agreement, unless otherwise permitted. For the purposes of this paragraph, liquid-hydrocarbon substances include natural gasoline and liquid-petroleum gas fractions.

Article XIII—*Automatic adjustment of unit area*

13.1 Any lease(s) not entitled to receive an allocation of unit production on the fifth/tenth anniversary of the effective date of the initial participating area established under this Agreement shall be eliminated automatically from the unit area as of said fifth/tenth anniversary; and thereafter, the unit area shall only be comprised of the participating area(s) subject to the provisions of Articles X and XVII.

13.2 If a lease is no longer subject to this Agreement in accordance with the provisions of this Article, that lease shall only be maintained and continued in force and effect in accordance with the terms and provisions contained in the Act, regulations, and the lease.

Article XIV—*Relinquishment of leases*

Pursuant to the provisions of the leases and applicable regulations, a lessee of record shall, subject to the provisions of the unit operating agreement, have the right to relinquish any of its interests committed hereto, in whole or in part, provided that no relinquishment shall be made of any interests within a participating area without the prior approval of the Regional Supervisor. In the event such relinquishments result in the leasehold interest of only one lease remaining committed hereto, this Agreement shall terminate automatically effective as of the date that only one lease remains subject to the Agreement.

Article XV—*Rentals and minimum royalties*

15.1 Rentals or minimum royalties due on leases committed hereto shall be paid by the working-interest owners responsible therefor at the time and rate(s) specified in their respective lease from the United States unless such rental or minimum royalty is suspended or reduced by law or by approval of the Secretary.

15.2 If there is production from the unit area during the lease year, the amount of royalty paid for production allocated to a lease during the lease year shall be credited against the minimum royalty obligation of the lease.

Article XVI—*Effective date and termination*

16.1 This Agreement shall be effective on ——— and shall terminate when oil or gas is no longer being produced from the unit area and drilling or well-reworking operations are no longer being conducted in accordance with the provisions of Article IX of this Agreement. If the Regional Supervisor has ordered or approved a suspension of operations or production on all or part of the unit area pursuant to the regulations, this Agreement shall be continued in force and effect for a period of time equal to the length of the authorized suspension and thereafter so long as operations are being conducted in accordance with the provisions of Article IX herein.

16.2 This Agreement may be terminated, with the approval of the Regional Supervisor, at any time by an affirmative vote of the owner(s) of a majority of the working-interests in each lease or portion thereof committed to this Agreement or as otherwise specified in the unit operating agreement.

Article XVII—*Leases and contracts conformed and extended*

17.1 The terms, conditions, and provisions of all leases, subleases, and other contracts relating to exploration, drilling, development, or production operations for oil or gas on lands committed to this Agreement are hereby modified and amended only to the extent necessary to make the same conform to the provisions hereof but otherwise shall remain in force and effect.

17.2 The Regional Supervisor, by the approval hereof, does hereby establish, alter, suspend, change, or revoke the drilling, production, rental, minimum royalty, and royalty requirements of the Federal leases committed hereto, to conform said requirements to the provisions of this Agreement, and without limiting the generality of the foregoing, all leases, subleases, and contracts are particularly modified in accordance with the following:

(a) Drilling and/or producing operations performed hereunder upon any unitized lease will be accepted and deemed to be performed upon and for the benefit of each and every unitized lease, and no lease committed to this Agreement shall be deemed to expire by reason of failure to drill or produce a well thereon.

(b) Suspension of drilling or producing operations on all unitized lands, pursuant to direction or consent of the Secretary or a duly authorized representative, shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every unitized lease.

(c) Suspension of drilling or producing operations on less than all unitized lands, pursuant to direction or consent of the Secretary or a duly authorized representative, shall be deemed to constitute such suspension pursuant to such direction or consent only as to unitized lands specified in the document providing direction or consent.

(d) Each lease committed hereto shall continue in force as to all lands covered thereby for the term so provided therein, or as extended by law, and so long thereafter as gas or oil and/or condensate is produced from a unit well in paying quantities, drilling or well-reworking operations pursuant to the regulations are conducted within the unit area, or operations are suspended hereunder as provided herein and operations are being conducted pursuant to the provisions of Article IX of this Agreement. This subsection shall not operate to continue in force any whole lease excluded from the unit area by adjustment pursuant to Articles X or XIII.

17.3 Upon termination of this Agreement, the leases committed hereto may be continued in force and effect in accordance with the terms and conditions contained in the Act, the regulations, and the leases.

Article XVIII—*Counterparts*

This Agreement may be executed in any number of counterparts, no one of which needs to be executed by all parties. If this Agreement is executed in counterparts, all counterparts taken together shall have the same effect as if all parties had signed the same instrument.

Article XIX—*Subsequent joinder*

The Regional Supervisor may order or, upon request, approve a subsequent joinder to this Agreement pursuant to the expansion provisions of Article X. A request for a subsequent joinder shall be accompanied by a signed counterpart to this Agreement and shall be submitted by the unit operator at the time a notice of proposed expansion is submitted pursuant to Article X. A subsequent joinder shall be subject to the requirements which may be contained in the unit operating agreement, if any, except that the Regional Supervisor may require modifications of any provision in a unit operating agreement which would prevent a subsequent joinder.

Article XX—*Remedies*

20.1 The failure of the unit operator to conduct operations in accordance with an approved plan of operation, to timely submit an acceptable plan for approval by the Regional Supervisor, or to comply with any other requirement of this Agreement in a timely manner shall, after notice of default to the unit operator with copies to all working-interest owners by the Regional Supervisor and after failure of the unit operator to remedy any default within a reasonable time as determined by the Regional Supervisor, result in automatic termination of this Agreement effective as of the first day of the default.

20.2 This remedy is in addition to any remedy which is prescribed in the Act, the regulations, or a lease committed to this Agreement or any action which may be brought by the United States to compel compliance with the provisions thereof.

Article XXI—*No waiver of certain rights*

Nothing contained in this Agreement shall be construed as a waiver by any party hereto of the right to assert any legal or constitutional right or defense pertaining to the validity or invalidity of any law of the United States, or regulations issued thereunder, in any way affecting such party or as a waiver by any such party of any right beyond such party's authority to waive.

Article XXII—*Covenants run with the land*

22.1 The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto and their successors in interest until this Agreement terminates, and any grant, transfer, or conveyance of interest in land or leases subject hereto shall be and hereby are conditioned upon the assumption of all privileges and obligations hereunder by the grantee, transferee, or other successor in interest.

22.2 No assignment or transfer of any working-interest or other interest subject hereto shall be binding upon the unit operator until the first day of the calendar month after the unit operator is furnished with the original, photostatic, or certified copy of the instrument of transfer.

In Witness Whereof, the working-interest owners and the unit operator have caused this Agreement to be executed as follows:

ACCEPTANCE OF RIGHTS AND OBLIGATIONS BY UNIT OPERATOR

I hereby accept and assume all rights and obligations of the unit operator as set forth above.

Dated: _____
Authorized Signature: _____
Name: _____
Title: _____
Corporation: _____
Subscribed and sworn to me this — day of 19 —.
Notary Public: _____
My Commission Expires: _____

APPROVAL BY WORKING-INTEREST OWNER(S)

As an owner of a working-interest in the unitized area, I hereby agree to the terms and conditions as set forth in this Agreement.

Dated: _____
Authorized Signature: _____
Name: _____
Title: _____
Corporation: _____
Address: _____
Subscribed and sworn to me this — day of 19 —.
Notary Public: _____
My Commission Expires: _____

(b) *Model unit agreement for development and production units.*

UNIT AGREEMENT FOR OUTER CONTINENTAL SHELF DEVELOPMENT AND PRODUCTION OPERATIONS ON THE ——— UNIT
BLOCKS ———, ——— AREA
OFFSHORE _____
CONTRACT NO. _____

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Witnesseth:

WHEREAS, section 5(a) of the Act authorizes the Secretary of the Interior (Secretary) to prescribe rules and regulations which shall provide for unitization, pooling, and drilling agreements;

WHEREAS, pursuant to the rules and regulations of the Secretary, 30 CFR 250.190, *et seq.*, it is deemed to be in the interest of conservation, prevention of waste, or protection of correlative rights to unitize the oil and gas interests in the unit area; and

WHEREAS, it is deemed to be necessary in the interest of conservation, for the prevention of waste, or for the protection of correlative rights to conduct development and production operations in the unit area as though the area were subject to a single lease;

NOW, THEREFORE, in consideration of the premises and promises contained herein, it is agreed that:

Article I—*Definitions*

The following definitions of terms shall apply to this Agreement:

"Act" means the OCS Lands Act of 1953, as amended, 43 U.S.C. 1331, *et seq.*

"Agreement" means this unit agreement, approved by the Regional Supervisor for conducting development and production operations within the unit area.

"Block" means an area designated as a block on a U.S. Official Leasing Protraction Diagram for an area of the OCS.

"Paying quantities" as used herein means the production of oil and/or gas in quantities sufficient to yield a return in excess of operating costs.

"Regional Supervisor" means the Regional Supervisor of MMS, Department of the Interior (DOI), or a designee authorized and empowered to regulate and approve unit operations.

"Regulations" means all rules prescribed or adopted pursuant to the Act. They include all regulations prescribed or amended at any time to provide for the prevention of waste, conservation of natural resources of the OCS, and the protection of correlative rights therein.

"Reservoir" means an underground porous, permeable medium containing an accumulation of oil or gas or both. Each zone of a general structure containing such an accumulation that is separated from any other accumulation of oil or gas or both in the structure is a separate "reservoir."

"Unit area" means the area of the OCS which is made subject to this Agreement and described in Article III.

"Unit operating agreement" means an agreement made between the working-interest owners and the unit operator providing for the apportionment of costs and liabilities incurred in conducting operations pursuant to this Agreement and the establishment of such other rights and obligations as they deem appropriate.

"Unit operator" means the person, association, partnership, corporation, or other business entity designated by the working-interest owners and approved by the Regional Supervisor to conduct unit operations within the unit area in accordance with a plan of operation approved pursuant to the Act, applicable regulations and this agreement.

"Unitized substances" means oil and/or gas within the reservoir(s) that underlie the unitized lands and which are recovered or produced by operations pursuant to this Agreement.

"Working-interest" means an interest in the unit area held by virtue of a lease, operating agreement, or other contractual arrangement under which, except as otherwise provided in this Agreement, the rights or authority to explore for, develop, and produce oil and gas are conferred. The right delegated to the unit operator by this Agreement is not a working-interest.

"Working-interest owner" means a party to this agreement that owns a working-interest.

Article II—*Incorporation*

All provisions of the Act, the regulations, other applicable laws, and the leases covering OCS lands within the unit area are made part of this Agreement.

Article III—*Unitized reservoir, unit area, and exhibits*

3.1 The (_____, reservoir _____) is defined as that productive zone occurring within the interval ____ feet to ____ feet, electric log depths, in Well No. ____, Lease OCS ____, hereinafter referred to as the unitized reservoir.

3.2 The area specified in Exhibit "A" is hereby designated and recognized as overlying the unitized reservoir and as constituting the unit area containing ____ acres, more or less. All oil and/or gas produced from the unitized reservoir, which lies within the unit area, are unitized under the terms of this Agreement and are referred to herein as unitized substances.

3.3 The above unit area may, subject to appropriate approval, be expanded to include therein additional acreage whenever such expansion is necessary or advisable to conform with the purposes of this Agreement.

3.4 Exhibit "A," attached hereto and made a part hereof, is a plat showing the unit area, boundaries, and oil and gas leases in said area. Exhibit "B," attached hereto and made a part hereof, is a schedule showing the acreage, percentage, and kind of ownership of oil and gas interests in all land in the unit area. Exhibit "C," attached hereto and made a part hereof, is a schedule setting out the number of productive net ____ acre-feet creditable to each tract under original reservoir conditions and the percentage of unit participation credited to each tract in the unit area. The number of net ____ acre-feet and the percentage of unit participation credited to each tract in Exhibit "C" are accepted and approved by the Regional Supervisor. Exhibits "A," "B," and "C" shall be revised by the unit operator whenever changes render it necessary, and four copies shall be filed with the Regional Supervisor for approval.

Article IV—*Designation of unit operator*

4.1 _____ is designated as the unit operator and agrees to accept the rights and obligations of the unit operator to develop and produce oil and/or gas as provided in this Agreement.

4.2 Except as otherwise provided in this Agreement and subject to the terms and conditions of approved plans of operations, the exclusive rights and obligations of the owners of working-interests to conduct unit operations to develop and produce oil and/or gas in the unit area are delegated to and shall be exercised by the unit operator. This delegation neither relieves a lessee of the obligation to comply with all lease terms nor transfers title to any lease or operating agreement.

Article V—*Resignation or removal of unit operator*

5.1 The unit operator shall have the right to resign at any time. Such resignation shall not become effective until 60 days after written notice of an intention to resign has been delivered by the unit operator to the working-interest owners and the Regional Supervisor and until all platforms, artificial islands, installations, and other devices, including wells used for conducting operations in the unit area are placed in a condition satisfactory to the Regional Supervisor for the transfer of operations, or, if no successor unit operator has been designated, for suspension or abandonment of operations. If a successor unit operator is designated and approved as provided in Article VI, the resignation shall be effective upon the designation and approval of the successor unit operator.

5.2 The unit operator may be subject to removal by the same percentage vote of the owners of working-interests as provided in Article VI for the designation of a successor unit operator. This removal shall not be effective until the working-interest owners notify the Regional Supervisor and the unit operator and until the Regional Supervisor approves the designation of a successor unit operator.

5.3 The resignation or removal of the unit operator shall not release the unit operator from liability for any failure to meet any obligations which accrued before the effective date of resignation or removal.

5.4 The resignation or removal of the unit operator shall not terminate any right, title, or interest as the owner of a working-interest or other interest in the unit area. However, when the resignation or removal of the unit operator becomes effective, the unit operator shall relinquish to the successor unit operator all wells, platforms, artificial islands, installations, devices, records, and other assets all owned solely by the unit joint account.

Article VI—*Successor unit operator*

6.1 Whenever the unit operator tenders a resignation as unit operator or is removed as provided in Article V, a successor unit operator may be designated by (a) an affirmative vote of the owner(s) of a majority of the working-interests, based on (1) their respective shares of the acreage subject to this Agreement; (2) their respective estimated volumes of oil or gas, or both, originally in place; or (3) their decision pursuant to the unit operating agreement, and (b) the successor unit operator's acceptance in writing of the rights and obligations of the unit operator. The successor unit operator shall file with the Regional Supervisor four executed copies of the designation of successor. However, the designation shall not become effective until approved by the Regional Supervisor.

6.2 If no successor unit operator is designated as herein provided within 60 days following notice to the Regional Supervisor of the unit operator's intent to resign or removal of a unit operator, the Regional Supervisor may elect to designate one of the working-interest owners other than the unit operator as successor unit operator or may declare this Agreement terminated.

Article VII—*Unit operating agreement*

7.1 The owners of working-interests and the unit operator shall enter into a unit operating agreement which shall describe how all costs and liabilities incurred in maintaining or conducting operations pursuant to this Agreement shall be apportioned and assumed. The unit operating agreement shall also describe how the benefits which may accrue from operations conducted on the unit area shall be apportioned.

7.2 The owners of working-interests and the unit operator may establish by means of one or more unit operating agreements such other rights and obligations as they deem necessary or appropriate. However, no provision of the unit operating agreement shall be deemed to modify the terms and conditions of this Agreement or to relieve the working-interest owners or the unit operator of any obligation set forth in this Agreement. In case of any inconsistency or conflict between this Agreement and the unit operating agreement, the terms of this Agreement shall prevail.

7.3 Three copies of the unit operating agreement executed in conjunction with the first paragraph of this Article shall be attached to this Agreement when it is filed with the Regional Supervisor with a request for approval. Three copies of all other unit operating agreements and any amendments thereto also shall be filed with the Regional Supervisor within 30 days of final execution.

Article VIII—*Appearances and notices*

8.1 The unit operator shall, after notice to other parties affected, have the right to appear on behalf of all working-interest owners before the DOI or any other body legally empowered to issue decisions concerning orders or regulations of the DOI and to appeal from these decisions. The expense of these appearances shall be paid and apportioned as provided in the unit operating agreement. However, any affected working-interest owners shall have the right at their own expense to be heard in any proceeding.

8.2 Any Order or notice relating to this Agreement which is given to the unit operator by the Regional Supervisor shall be deemed given to all working-interest owners of the unit area. All notices required by this Agreement to be given to the unit operator or the owners of working-interests shall be deemed properly given if in writing and delivered personally or sent by prepaid registered or certified mail to the addresses set forth below or to such other addresses as may have been furnished in writing to the party sending the notice.

Article IX—*Plan of operation*

9.1 The unit operator shall submit plans of operation which are consistent with the requirements for a Development and Production Plan as required by the Act, Subpart B of 30 CFR Part 250, and other sections of the regulations. All operations within the unit area shall be conducted in accordance with an approved plan.

9.2 When no oil or gas is being produced in paying quantities from the unit area and when all or part of the area is subject to one or more leases beyond the primary term, a continuous drilling or well-reworking program shall be maintained with lapses of no more than 90 days per lapse between such operations unless a suspension of production or other operation has been ordered or approved by the Regional Supervisor, or unless extended by the Director pursuant to 30 CFR 250.13(b). The plan may call for a cessation of drilling operations for a reasonable period of time after the discovery and delineation of this unitized reservoir when such a pause in drilling activities is warranted to permit the design, fabrication, and erection of platforms and other installations needed for development and production operations, provided a suspension of production or other operation has been ordered or approved by the Regional Supervisor.

9.3 An acceptable initial plan of operation shall be submitted at the time this Agreement is filed for the Regional Supervisor's approval. Each plan of operation shall expire on the date specified in the plan. At least 60 days before the scheduled expiration of any plan, unless the Regional Supervisor grants an extension for good cause, the unit operator shall file an acceptable subsequent plan of operation for approval in accordance with this Article.

Article X—*Revision of unit area and allocation of production*

10.1 Unitized substances produced from the unit area shall be allocated on the basis of net acre-feet, under original reservoir conditions, credited to the respective tracts committed hereto. A net acre-foot as used in this Agreement means one acre of producing formation which contains one foot of net ____ pay. Oil and/or gas produced from the unit area prior to the effective date of this Agreement shall not be allocated under this Agreement. The royalty payments under leases committed hereto shall be based and calculated upon the production allocated to the tracts as specifically provided herein.

10.2 The unit area so established shall be revised from time to time, subject to the approval of the Regional Supervisor, whenever such action appears proper as a result of further drilling operations or otherwise to include additional lands or to exclude lands. The effective date of any revision of the unit area shall be the first day of the month in which is obtained the knowledge or information on which such revision is predicated, provided that a more appropriate effective date may be used if justified by the unit operator and approved by the Regional Supervisor.

10.3 In the event any lands are added to the unit area a reasonable and fair participation shall be allocated to the new lands on the basis of net acre-feet. The determination of the net acre-feet creditable to such lands shall be done in the same manner and by the same procedures used to determine the tract percentages of participation as shown on Exhibit "C." If the unit area is so expanded, the net acre-feet credited to land originally in the unit area shall not be subject to change. The only change will be to increase the total number of net acre-feet in the unit area by adding to the original total the total number of net acre-feet allocated to new lands, provided that there shall never be any retroactive allocation of interest in the unitized substances produced, or the proceeds thereof, by reason of any revision.

10.4 The unit operator shall pay all production royalties and make deliveries of oil and gas which are payments of royalties taken-in-kind or which, pursuant to the Act, are purchased by the United States.

10.5 For the purpose of determining royalty obligations, gas and liquid-hydrocarbon substances on which royalty has been paid and which are used for repressuring, stimulation of production, or increasing ultimate recovery from the unit area, in conformity with an approved plan of operation, may be deemed to be a portion of the gas and liquid-hydrocarbon substances subsequently saved, removed, or sold from the unit area. In such instances, a like amount of gas and liquid-hydrocarbon substances similar to that previously used may be saved, removed, or sold from the unit area without paying a royalty thereon. However, as to dry gas, only dry gas and not products extracted therefrom may be saved, removed, or sold royalty free. The royalty-free withdrawal shall be accomplished in accordance with an approved plan of operation, and the shares of gas and liquid-hydrocarbon substances withdrawn that are to be recognized as free of royalty charges shall be computed in accordance with a formula approved or prescribed by the Regional Supervisor. Any withdrawal of royalty-free gas or liquid-hydrocarbon substances shall terminate upon the termination of this Agreement, unless otherwise permitted. For the purposes of this paragraph, liquid-hydrocarbon substances include natural gasoline and liquid-petroleum gas fractions.

Article XI—*Relinquishment of leases*

Pursuant to the provisions of the lease and applicable regulations a lessee of record shall, subject to the provisions of the unit operating agreement, have the right to relinquish any of its interests committed hereto, provided that no relinquishment shall be made of any interests within the unit area without the prior approval of the Regional Supervisor.

Article XII—*Rentals and minimum royalties*

12.1 Rentals or minimum royalties due on leases committed hereto shall be paid by the working-interest owners responsible therefor at the time and rate(s) specified in their respective lease from the United States unless such rental or minimum royalty is suspended or reduced by law or by approval of the Secretary.

12.2 If there is production from the unit area during the lease year, the amount of royalty paid for production allocated to a lease during the lease year shall be credited against the minimum royalty obligation of the lease.

Article XIII—*Effective date and termination*

13.1 This Agreement shall be effective on _____ and shall terminate when oil and/or gas is no longer being produced from the unit area and drilling or well-reworking operations are no longer being conducted in accordance with the provisions of Article IX of this Agreement. If the Regional Supervisor has ordered a suspension of operations or production on all or part of the unit area pursuant to the regulations, this Agreement shall be continued in force and effect for a period of time equal to the length of the authorized suspension and thereafter so long as operations are being conducted in accordance with the provisions of Article IX herein.

13.2 This Agreement may be terminated, with the approval of the Regional Supervisor, at any time by an affirmative vote of the owner(s) of a majority of the working-interests in each lease or portion thereof committed to this Agreement or as otherwise specified in the unit operating agreement.

Article XIV—*Leases and contracts conformed and extended*

14.1 The terms, conditions, and provisions of all leases, subleases, and other contracts relating to drilling, development, or production operations for oil or gas on lands committed to this Agreement are hereby modified and amended only to the extent necessary to make the same conform to the provisions hereof but otherwise shall remain in force and effect.

14.2 The Regional Supervisor, by the approval hereof, does hereby establish, alter, suspend, change, or revoke the drilling, production, rental, minimum royalty, and royalty requirements of the Federal leases committed hereto, to conform said requirements to the provisions of this Agreement, and without limiting the generality of the foregoing, all leases, subleases, and contracts are particularly modified in accordance with the following:

(a) Drilling and/or producing operations performed hereunder upon any unitized lease will be accepted and deemed to be performed upon and for the benefit of each and every unitized lease, and no lease committed to this Agreement shall be deemed to expire by reason of failure to drill or produce a well thereon.

(b) Suspension of drilling or producing operations on all unitized lands, pursuant to direction or consent of the Secretary or a duly authorized representative, shall be deemed to constitute such suspension pursuant to such direction or consent as to each and every unitized lease.

(c) Suspension of drilling or producing operations on less than all unitized lands pursuant to direction or consent of the Secretary, or a duly authorized representative, shall be deemed to constitute such suspension pursuant to such direction or consent only as to those unitized lands specified in the document providing direction or consent.

(d) Each lease committed hereto shall continue in force as to all lands covered thereby for the term so provided therein, or as extended by law, and so long thereafter as gas or oil and/or condensate are produced from a unit well in paying quantities, drilling or well-reworking operations pursuant to the regulations are conducted within the unit area, or operations are suspended hereunder as provided herein, and operations are being conducted pursuant to the provisions of Article IX of this Agreement. This subsection shall not operate to continue in force any whole lease excluded from the unit area by adjustment pursuant to Article X.

14.3 Upon termination of this Agreement, the leases committed hereto may be continued in force and effect in accordance with the terms and conditions contained in the Act, the regulations, and the leases.

Article XV—*Counterparts*

This Agreement may be executed in any number of counterparts, no one of which needs to be executed by all parties. If this Agreement is executed in counterparts, all counterparts taken together shall have the same effect as if all parties had signed the same instrument.

Article XVI—*Subsequent joinder*

The Regional Supervisor may order or, upon request, approve a subsequent joinder to this Agreement pursuant to the expansion provisions of Article X. A request for a subsequent joinder shall be accompanied by a signed counterpart to this Agreement and shall be submitted by the unit operator at the time a notice of proposed expansion is submitted pursuant to Article X. A subsequent joinder shall be subject to the requirements which may be contained in the unit operating agreement, if any, except that the Regional Supervisor may require modifications of any provision in a unit operating agreement which would prevent a subsequent joinder.

Article XVII—*Remedies*

17.1 The failure of the unit operator to conduct operations in accordance with an approved plan of operation, to timely submit an acceptable plan for approval by the Regional Supervisor, or to comply with any other requirement of this Agreement in a timely manner shall, after notice of default to the unit operator with copies to all working-interest owners by the Regional Supervisor and after failure of the unit operator to remedy any default within a reasonable time as determined by the Regional Supervisor, result in automatic termination of this Agreement effective as of the first day of the default.

17.2 This remedy is in addition to any remedy which is prescribed in the Act, the regulations, or a lease committed to this Agreement or any action which may be brought by the United States to compel compliance with the provisions thereof.

Article XVIII—*No waiver of certain rights*

Nothing contained in this Agreement shall be construed as a waiver by any party hereto of the right to assert any legal or constitutional right or defense pertaining to the validity or invalidity of any law of the United States, or regulations issued thereunder, in any way affecting such party or as a waiver by any such party of any right beyond such party's authority to waive.

Article XIX—*Covenants run with the land*

19.1 The covenants herein shall be construed to be covenants running with the land with respect to the interest of the parties hereto in the unitized reservoir and their successors in interest until this Agreement terminates, and any grant, transfer, or conveyance of interest in land or leases subject hereto shall be and hereby are conditioned upon the assumption of all privileges and obligations hereunder by the grantee, transferee, or other successor in interest.

19.2 No assignment or transfer of any working-interest or other interest subject hereto shall be binding upon the unit operator until the first day of the calendar month after the unit operator is furnished with the original, photostatic, or certified copy of the instrument of transfer.

In Witness Whereof, the working-interest owners and the unit operator have caused this Agreement to be executed as follows:

ACCEPTANCE OF RIGHTS AND OBLIGATIONS BY UNIT OPERATOR

I hereby accept and assume all rights and obligations of the unit operator as set forth above.

Dated: _____
Authorized Signature: _____
Name: _____
Title: _____
Corporation: _____
Address: _____
Subscribed and sworn to me this ____ day of ____, 19____.
Notary Public: _____
My Commission Expires: _____

APPROVAL BY WORKING-INTEREST OWNER(S)

As an owner of a working-interest in the unitized area, I hereby agree to the terms and conditions as set forth in this Agreement.

Dated: _____
Authorized Signature: _____
Name: _____
Title: _____
Corporation: _____
Address: _____
Subscribed and sworn to me this ____ day of ____, 19____.
Notary Public: _____
My Commission Expires: _____

Subpart N—Remedies and Penalties

§ 250.200 Remedies.

(a) (1) Whenever the Regional Director determines, on the basis of available evidence, that a violation of or failure to comply with any provision of the Outer Continental Shelf Lands Act (Act), or any provision of a lease, license, or permit issued pursuant to the Act, or any provision of any regulation issued under the Act (hereinafter referred to as "violation") probably occurred and that such violation continued beyond actual notice of the violation and the expiration of any reasonable period allowed for corrective action, the Regional Director may direct the preparation of a case file, and appoint a Minerals Management Service (MMS) employee to serve as a Reviewing Officer. In making this determination, the Regional Director shall have the authority to summon witnesses, administer oaths, and issue orders to produce evidence. Chairmen of investigative panels appointed by the Regional Director to investigate violations or other matters shall also have authority to summon witnesses, administer oaths, and issue orders to produce evidence while conducting investigations.

(2) The Reviewing Officer shall have no other responsibility, direct or supervisory, for the investigation or prosecution of the case.

(3) The Reviewing Officer shall decide each case on the basis of the evidence of record.

(4) The Reviewing Officer may administer oaths and issue subpoenas requiring the attendance of witnesses at hearings or for the taking of depositions and may issue orders to produce evidence.

(5) The Reviewing Officer may assess civil penalties and, when appropriate, recommend the initiation of criminal proceedings.

(b) If the Reviewing Officer determines that there is sufficient evidence that a violation probably occurred and that the violation continued beyond any notice of such failure and the expiration of any reasonable period allowed for corrective action, the Reviewing Officer shall notify in writing the person alleged to have committed the violation (hereinafter referred to as "party") of the following:

(1) The alleged violation, citing the applicable provision of the Act, or the applicable term of a lease, license, or permit issued pursuant to the Act, or the applicable provision of a regulation or order issued under the Act upon which the action is based;

(2) The amount of penalty that appears would be appropriate in the event it is determined that the party is responsible for the alleged violation based upon the material then available to the Reviewing Officer;

(3) The party's right to examine the material in the case file and to have a copy of all written documents provided upon request, except those which would, in a civil proceeding, disclose or lead to the disclosure of a confidential informant; and

(4) The fact that, subject to the provisions in § 250.201 of this part, the party has a right to a hearing before the

Reviewing Officer prior to any finding of fact regarding the alleged violation.

(c) A party has the right to be represented by counsel, qualified to practice before the Department of the Interior (DOI) under 43 CFR Part 1, at all stages of the proceeding. After receiving notification that a party is represented by counsel, the Reviewing Officer shall direct all further communications to the counsel.

§ 250.201 Hearings.

(a) Within 30 days after receipt of a notice pursuant in § 250.200(b) of this part, the party may accomplish one of the following:

(1) Request a hearing before the Reviewing Officer,

(2) Provide any written evidence and arguments in lieu of a hearing, or

(3) Pay the amount specified in the notice.

(b) A request for a hearing before the Reviewing Officer shall be in writing and specify the particular issues which are in dispute. Failure to specify a nonjurisdictional issue will preclude its consideration except as the Reviewing Officer determines to be necessary or desirable in the interest of obtaining a fair resolution of the case.

(1) The Reviewing Officer may grant the party additional time to submit a request for a hearing.

(2) The Reviewing Officer shall promptly schedule all requested hearings to be held in the office of the Reviewing Officer or such other location as the Reviewing Officer may designate. The Reviewing Officer shall grant any delays or continuances which the Reviewing Officer determines to be necessary or desirable in the interest of obtaining a fair resolution of the case.

(c) Prior to a hearing, the party may examine all evidence in the case file except material that would disclose or lead to the disclosure of the identity of a confidential informant.

(d)(1) Confidential treatment shall be accorded to all or a portion of any document at the request of the person supplying the information if the information is as follows:

(i) Confidential financial information, trade secrets, or other material exempt from disclosure under the Freedom of Information Act (5 U.S.C. 552);

(ii) Information required to be held in confidence by these regulations; or

(iii) Information that is otherwise exempt by law from disclosure.

(2) The person desiring confidential treatment of information shall submit a written request to the Reviewing Officer stating the reasons justifying nondisclosure.

(e) The Regional Director may, upon request of a party, transfer the case to another Reviewing Officer or direct that the hearing be held at a location other than that specified by the Reviewing Officer.

(f) (1) The testimony of any witness may be presented either through a personal appearance or through a written statement.

(2) A witness may be required to attend a hearing or the taking of a deposition at a place not more than 100 miles from the place of service.

(3) Witnesses subpoenaed shall be paid the same fees and mileage paid for similar services in the U.S. District Courts. These expenses shall be paid by the party at whose insistence the witness appears.

(4) Any witness who attends a hearing or the taking of a deposition at the request of the party, without having been subpoenaed to do so, shall be entitled to the same mileage and attendance fees paid to a subpoenaed witness. The witness fees and mileage shall be paid by the party at whose request the witness appears.

(5) In cases where an individual cannot be required to appear as a witness, the Reviewing Officer may move the hearing to the location of the desired witness, accept a written statement, or accept a stipulation in lieu of testimony.

§ 250.202 Hearing procedures.

(a) Material in the case file which is pertinent to the issues shall be presented to the party who may respond to or rebut this material. The party may offer any facts, statements, explanations, documents, sworn or unsworn testimony, or other items which bear on the issues or which may be relevant to the amount of the penalty to be assessed if the party is found to be guilty of the alleged violation. The Reviewing Officer may require the authentication of any written exhibit or statement.

(b) The party may request an opportunity to submit additional written testimony for consideration by the Reviewing Officer. The Reviewing Officer shall allow a reasonable time for submission of additional written testimony and shall specify the date by which it must be received.

(c) The Reviewing Officer may take notice of matters which are subject to a high degree of indisputability and are commonly known in the community or are ascertainable from readily available sources of known accuracy. Prior to taking notice of a matter, the Reviewing Officer shall give the party an opportunity to show why notice should not be taken. In any case in which such notice is taken, the Reviewing Officer shall place in the record a written statement on the matter of which notice was taken and the basis for taking such notice. The Reviewing Officer's statement shall indicate that the party consented to notice being taken or shall include a summary of the party's objections to notice being taken of a specific matter.

(d) In evaluating the evidence presented, the Reviewing Officer shall give due consideration to the reliability and relevance of each item of evidence but is not bound by strict rules of evidence.

(e) (1) A verbatim transcript of hearings before a Reviewing Officer need not be prepared. The Reviewing Officer shall prepare notes on the material and points raised by the party in sufficient detail to permit a full and fair review and resolution of the case should it be appealed.

(2) A party may, at its own expense, cause a verbatim transcript to be made. If a verbatim transcript is made and the Reviewing Officer's decision is appealed, the party shall submit a copy of the verbatim transcript with the appeal to the Director and to the Reviewing Officer for inclusion in the case file.

§ 250.203 Reviewing Officer's decision.

(a) The Reviewing Officer's decision shall be in writing and shall include the Reviewing Officer's conclusions and the basis for them. Any decision shall be based upon substantial evidence in the record. If the Reviewing Officer finds that there is not substantial evidence in the record establishing that the alleged violation occurred, or that the required notice of the alleged violation was not provided, or that the alleged violation did not continue after the termination of any period provided for the taking of corrective action, the Reviewing Officer shall dismiss the case and remand it to the Regional Director. A dismissal is without prejudice to the Regional Director's right to refile the case and have it reheard if additional evidence is obtained. A dismissal following a rehearing is final and with prejudice.

(b) The Reviewing Officer's decision shall contain a statement advising the party of the right to an administrative appeal to the Director pursuant to 30 CFR Part 290 of this title. The party shall be advised that failure to submit an appeal within the prescribed time will bar its consideration and that failure to appeal on the basis of a particular issue will constitute a waiver of that issue in any subsequent proceeding. An appeal

from any interim ruling of the Reviewing Officer shall be reserved and considered only at the time of and as part of an appeal from the Reviewing Officer's final decision.

§ 250.204 Appeals from Reviewing Officer's decision.

(a) (1) Any appeal from a decision of the Reviewing Officer, together with any supporting argument, shall be submitted by a party to the Director within 30 days after the date of receipt of the decision. The appellant shall provide a copy of the notice of appeal and supporting brief to the Reviewing Officer. Except as provided in § 250.205 of this part, the only issues which will be considered on appeal are jurisdictional questions and those issues specified in the notice of appeal which were properly raised before the Reviewing Officer.

(2) The failure to file a notice of appeal within the time prescribed shall result in the action of the Reviewing Officer becoming the final action of the DOI in the case.

(b) A copy of all of the Reviewing Officer's comments on the appeal submitted to the Director shall be provided to the appellant.

(c) (1) The Director may affirm, reverse, or modify the Reviewing Officer's decision or remand the case for new or additional proceedings.

(2) The Director may increase, remit, mitigate, or suspend, in whole or in part, any penalty assessed by the Reviewing Officer.

(d) The Director's decision shall be in writing, and copies shall be provided to the appellant and the Reviewing Officer.

(e) In the absence of an appeal from the Director's decision pursuant to 30 CFR Part 290, the Director's decision on an appeal shall be final. (See § 250.23 of this part.)

§ 250.205 Reopening a case.

(a) (1) At any time prior to final MMS action in a civil-penalty case, a party may petition to reopen the proceedings on the basis of newly discovered evidence.

(2) Petitions to reopen a case must be in writing. Petitions shall describe the newly found evidence and state why the evidence would probably produce a different result favorable to the petitioner. The petitioner shall state whether the evidence was known to the petitioner at the time of the proceedings and, if not, why the newly found evidence could not have been discovered during the previous proceedings. The party shall submit the petition to the Reviewing Officer and provide a copy to the Regional Director.

(3) The Reviewing Officer shall consider a petition to reopen a case unless an appeal has been filed. In those cases where an appeal has been timely filed, a petition to reopen a case shall be considered by the Director.

(4) A petition to reopen a case shall be granted only when the Reviewing Officer or Director determines that the petition explains why newly found evidence that would have a direct and material bearing on the issue(s) of the case was not and could not have been produced at the time of the previous proceedings. A decision on a petition to reopen a case shall be in writing. A new decision issued by the Reviewing Officer, on the basis of newly found evidence, may be appealed to the Director in accordance with § 250.204 of this part.

(b) The denial of a petition to reopen a case shall be final and may not be appealed in an action separate from the appeal of the case pursuant in § 250.204 of this part or 30 CFR Part 290 of this title.

(c) The Regional Director may, on the basis of newly found evidence, that would probably produce a different result, reopen a case pursuant to § 250.203(a) of this part.

§ 250.206 Civil-penalties.

(a) (1) If the Reviewing Officer determines that a civil-penalty is to be assessed, the penalty shall be determined in accordance with the provisions of section 24(b) of the Act.

(2) If the Reviewing Officer's decision is appealed to the Director, payment of a civil-penalty shall not be due until after the Director's decision on the appeal is issued. If administrative relief is pursued following the Director's decision, a bond guaranteeing payment may be posted in lieu of actual payment.

(3) The MMS's Associate Director for Royalty Management shall collect civil-penalties assessed by a Reviewing Officer, the Director, or DOI's Board of Land Appeals.

(4) Payment of a civil-penalty shall be in accordance with instructions that accompany the Bill for Collection (Form DI–10406) sent to the party upon whom the penalty is imposed.

(b) Within 30 days after receipt of the bill issued by MMS's Royalty Management Program Accounting Division, the party shall submit payment of the assessed penalty to MMS's Accounting Center unless an appeal is filed in accordance with § 250.204 of this part. Failure to either make timely payment or file a timely appeal will result in the collection of the amount assessed plus interest from the date of assessment until the date of payment as determined by MMS. Interest shall be computed on a daily basis at the rate applicable under section 6621 of the Internal Revenue Code of 1954. Such failure may also result in the initiation of additional enforcement proceedings including, if appropriate, cancellation of the lease or permit or forfeiture of a bond under this part.

Subpart O—Training

§ 250.210 Documents incorporated by reference.

The documents listed below are incorporated by reference as requirements in this subpart. The Director of the Federal Register approved the incorporation by reference of these documents on May 31, 1988. These documents are incorporated as they existed on the date of the approval, and a notice of any change in these douments will be published as a rule change in the **Federal Register**. Each document or specific portion thereof is incorporated by reference in the corresponding sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections calls for compliance with specific portions of the listed documents. In each instance, the applicable document is the specific edition or specific edition and supplement cited in this section. In accordance with § 250.3, performance requirements, the lessee may comply with a later edition of a specific document incorporated by reference provided the lessee can demonstrate that compliance with the later edition provides a degree of protection, safety, or performance equal to or better than that which would be achieved by compliance with the listed edition and provided the lessee obtains the prior written approval of the authorized Minerals Management Service (MMS) official, as appropriate, for such alternative compliance. The list includes the name and address of at least one organization from whom the document may be purchased. These documents are also available for inspection at the Office of the Federal Register Information Center, Room 8301, 1100 L Street NW., Washington, DC 20408. In order to facilitate correlation of the test of the corresponding sections with the list of documents incorporated by reference, the documents are listed in alphanumerical order.

(a) *American Petroleum Institute (API) Document.* The API document listed in this paragraph may be purchased from the American Petroleum

Institute, Production Department, 211 N. Ervay, Suite 1700, Dallas, Texas 75201, or American Petroleum Institute, 1220 L Street NW., Washington, DC 20005.

API RP T–2, Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices, Revised October 1975, API Stock No. 811–13710, Incorporated by Reference at: § 250.212 of this subpart.

(b) *Minerals Management Service Document.* The MMS document listed in this paragraph may be obtained from the Minerals Management Service, Mail Stop 646, 12203 Sunrise Valley Drive, Reston, Virginia 22091, or from one of the Regional Offices of MMS's Offshore Minerals Management Program.

MMSS–OCS–T–1, Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations, Second Edition, May 1982, Incorporated by Reference at: § 250.211 of this subpart.

§ 250.211 Well control training.

Lessee and drilling contractor personnel shall be trained in accordance with MMS Standard MMSS–OCS–T–1, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," Second Edition, May 1982.

§ 250.212 Safety device training.

(a) Lessee and contract personnel installing, inspecting, testing, and maintaining antipollution safety devices and systems and personnel operating offshore production platforms shall be qualified under a program identified in API RP T–2, Qualification Programs for Offshore Production Personnel Who Work with Anti-Pollution Safety Devices. The aforementioned personnel shall repeat the basic API RP T–2 course every 4 years.

(b) Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area or other locations conveniently available to the District Supervisor.

(c) Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company, provided they have received training and are qualified by the manufacturer to install, service, or repair the specific safety device or safety system and if they are accompanied by an API RP T–2–qualified person who is capable of evaluating the impact of the work on the total system.

(d) On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Subpart P—Sulphur Operations

§ 250.250 Requirements for sulphur operations.

Lessees shall conduct sulphur exploration, development, and production operations in the Gulf of Mexico (GOM) Outer Continental Shelf (OCS) Region in accordance with the GOM OCS Order No. 10 and with the requirements of this part.

PART 256—[AMENDED]

3. The authority for Part 256 continues to read as follows:

Authority: Secretarial Order 3071, Amendment No. 1, May 10, 1982, and the OCS Lands Act, 43 U.S.C. 1331 et seq., as amended, 92 Stat. 629.

4. In Part 256, Subpart N of Title 30, consisting of §§ 256.83–256.101, is removed.

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