SUBCHAPTER B—OFFSHORE

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

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AUTHORITY: 43 U.S.C. 1331, *et seq.*

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Subpart A—General

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AUTHORITY AND DEFINITION OF TERMS

§ 250.101 Authority and applicability.

The Secretary of the Interior (Secretary) authorized the Minerals Management Service (MMS) to regulate oil, gas, and sulphur exploration, development, and production operations on the outer Continental Shelf (OCS). Under the Secretary's authority, the Director requires that all operations:

(a) Be conducted according to the OCS Lands Act (OCSLA), the regulations in this part, MMS orders, the lease or right-of-way, and other applicable laws, regulations, and amendments; and

(b) Conform to sound conservation practice to preserve, protect, and develop mineral resources of the OCS to:

(1) Make resources available to 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 receives 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.

§ 250.102 What does this part do?

(a) 30 CFR part 250 contains the regulations of the MMS Offshore program that govern oil, gas, and sulphur exploration, development, and production operations on the OCS. When you conduct operations on the OCS, you must submit requests, applications, and notices, or provide supplemental information for MMS approval.

(b) The following table of general references shows where to look for information about these processes.

TABLE—WHERE TO FIND INFORMATION FOR CONDUCTING OPERATIONS

For information about	Refer to
(1) Abandoning wells	§ 250.701.
(2) Applications for Permit to Drill	§ 250.414.
(3) Development and Production Plans (DPP)	§ 250.204.
(4) Downhole commingling	§ 250.1106.
(5) Exploration Plans (EP)	§ 250.203.
(6) Flaring	§ 250.1105.
(7) Gas measurement	§ 250.1203.
(8) Off-lease geological and geophysical permits	30 CFR 251.
(9) Oil spill financial responsibility coverage	30 CFR 253.
(10) Oil and gas production safety systems	§ 250.802.
(11) Oil spill response plans	30 CFR 254.
(12) Oil and gas well-completion operations	§ 250.513.
(13) Oil and gas well-workover operations	§ 250.613.
(14) Platforms and structures	§ 250.901.
(15) Pipelines	§ 250.1009.
(16) Pipeline right-of-way	§ 250.1010.
(17) Sulphur operations	§ 250.1604.
(18) Training	§ 250.1500.
(19) Unitization	§ 250.1300.

§ 250.103 Where can I find more information about the requirements in this part?

MMS may issue Notices to Lessees and Operators (NTLs) that clarify, supplement, or provide more detail about certain requirements. NTLs may also outline what you must provide as required information in your various submissions to MMS.

§ 250.104 How may I appeal a decision made under MMS regulations?

To appeal orders or decisions issued under MMS regulations in 30 CFR parts 250 to 282, follow the procedures in 30 CFR part 290.

§ 250.105 Definitions.

Terms used in this part will have the meanings given in the Act and as defined in this section:

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 under the provisions of the Act, any State:

(1) The laws of which are declared, under 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 according to the proposed activity, will receive oil for processing, refining, or transshipment that 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 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, under 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 that have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analysis, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

Archaeological interest means capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics through the application of scientific or scholarly techniques, such as controlled observation, contextual measurement, controlled collection, analysis, interpretation, and explanation.

Archaeological resource means any material remains of human life or activities that are at least 50 years of age and that are of archaeological interest.

Attainment area means, for any air pollutant, an area that is shown by monitored data or that 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 and safest technology (BAST) means the best available and safest technologies that the Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.

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 Regional Director will verify the BACT on a case-by-case basis, and it 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 that 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, under 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 producible or producing well completions on each of two or more leases or portions of leases, with different lease operating interests, from which the lessees plan future production.

Correlative rights when used with respect to lessees of adjacent leases, means the right of each lessee to be afforded an equal opportunity to explore for, develop, and produce, without waste, minerals from a common source.

Data means facts and statistics, measurements, or samples that have not been analyzed, processed, or interpreted.

Departures means approvals granted by the appropriate MMS representative for operating requirements/procedures other than those specified in the regulations found in this part. These requirements/procedures may be necessary to control a well; properly develop a lease; conserve natural resources, or protect life, property, or the marine, coastal, or human environment.

Development means those activities that take place following discovery of minerals in paying quantities, including but not limited to geophysical activity, drilling, platform construction, and operation of all directly related onshore support facilities, and which are for the purpose of producing the minerals discovered.

Director means the Director of MMS of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

District Supervisor means the MMS officer with authority and responsibility for operations or other designated program functions for a district within an MMS Region.

Easement means an authorization for a nonpossessory, nonexclusive interest in a portion of the OCS, whether leased or unleased, which specifies the rights of the holder to use the area embraced in the easement in a manner consistent with the terms and conditions of the granting authority.

Eastern Gulf of Mexico means all OCS areas of the Gulf of Mexico the Director decides are adjacent to the State of Florida. The Eastern Gulf of Mexico is not the same as the Eastern Planning Area, an area established for OCS lease sales.

Emission offsets means emission reductions obtained from facilities, either onshore or offshore, other than the facility or facilities covered by the proposed Exploration Plan (EP) or Development and Production Plan (DPP).

Enhanced recovery operations means pressure maintenance operations, secondary and tertiary recovery, cycling, and similar recovery operations that alter the natural forces in a reservoir to increase the ultimate recovery of oil or gas.

Existing facility, as used in § 250.303, means an OCS facility described in an Exploration Plan or a Development and Production Plan approved before June 2, 1980.

Exploration means the commercial search for oil, gas, or sulphur. Activities classified as exploration include but are not limited to:

(1) Geophysical and geological (G&G) surveys using magnetic, gravity, seismic reflection, seismic refraction, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur; and

(2) Any drilling conducted for the purpose of searching for commercial quantities of oil, gas, and sulphur, including the drilling of any additional well needed to delineate any reservoir to enable the lessee to decide whether to proceed with development and production.

Facility means:

(1) As used in § 250.130, any installation permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). It includes mobile

offshore drilling units (MODUs) or other vessels engaged in drilling or downhole operations, used for oil, gas, or sulphur drilling, production, or related activities. It also includes facilities for product measurement and royalty determination (e.g., Lease Automatic Custody Transfer units, gas meters) of OCS production on installations not on the OCS. Any group of OCS installations interconnected with walkways, or any group of installations that includes a central or primary installation with processing equipment and one or more satellite or secondary installations is a single facility. The Regional Supervisor may decide that the complexity of the individual installations justifies their classification as separate facilities.

(2) As used in § 250.303, means any installation or device permanently or temporarily attached to the seabed. It includes mobile offshore drilling units (MODUs), even while operating in the ''tender assist'' mode (i.e. with skid-off drilling units) or other vessels engaged in drilling or downhole operations. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(3) As used in § 250.417(b), 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 associated gas-cap of an oil reservoir.

Governor means the Governor of a State, or the person or entity designated by, or under, State law to exercise the powers granted to such Governor under the Act.

H_2S absent means:

(1) Drilling, logging, coring, testing, or producing operations have confirmed the absence of H_2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S; or

(2) Drilling in the surrounding areas and correlation of geological and seismic data with equivalent stratigraphic units have confirmed an absence of H_2S throughout the area to be drilled.

H_2S present means drilling, logging, coring, testing, or producing operations have confirmed the presence of H_2S in concentrations and volumes that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S.

H_2S unknown means the designation of a zone or geologic formation where neither the presence nor absence of H_2S has been confirmed.

Human environment means the physical, social, and economic components, conditions, and factors that 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.

Interpreted geological information means geological knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of data and analyzed geological information.

Interpreted geophysical information means geophysical knowledge, often in the form of schematic cross sections, 3-dimensional representations, and maps, developed by determining the geological significance of geophysical data and analyzed geophysical information.

Lease means an agreement that is issued under section 8 or maintained under section 6 of the Act and that authorizes exploration for, and development and production of, minerals. The term also means the area covered by that authorization, whichever the context requires.

Lease term pipelines means those pipelines owned and operated by a lessee or operator that are completely contained within the boundaries of a single lease, unit, or contiguous (not cornering) leases of that *lessee* or operator.

Lessee means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals. The term lessee also includes the MMS-approved assignee of the lease, and the owner or the MMS-approved assignee of operating rights for the lease.

Major Federal action means any action or proposal by the Secretary that is subject to the provisions of section 102(2)(C) of the National Environmental Policy Act of 1969, 42 U.S.C. (2)(C) (i.e., an action that will have a significant impact on the quality of the human environment requiring preparation of an environmental impact statement under section 102(2)(C) of the National Environmental Policy Act).

Marine environment means the physical, atmospheric, and biological components, conditions, and factors that interactively determine the productivity, state, condition, and quality of the marine ecosystem. These include 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.

Material remains means physical evidence of human habitation, occupation, use, or activity, including the site, location, or context in which such evidence is situated.

Maximum efficient rate (MER) means the maximum sustainable daily oil or gas withdrawal rate from a reservoir that 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.

Minerals includes oil, gas, sulphur, geopressured-geothermal and associated resources, and all other minerals that are authorized by an Act of Congress to be produced.

Natural resources includes, without limiting the generality thereof, oil, gas, and all other minerals, and fish, shrimp, oysters, clams, crabs, lobsters, sponges, kelp, and other marine animal and plant life but does not include water power or the use of water for the production of power.

Nonattainment area means, for any air pollutant, an area that is shown by monitored data or that 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.

Operating rights means any interest held in a lease with the right to explore for, develop, and produce leased substances.

Operator means the person the lessee(s) designates as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the MMS-approved designated agent of the lessee(s), or the holder of operating rights under an MMS-approved operating rights assignment.

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) whose 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 (including partnerships and trusts), a State, a political subdivision of a State, or a private, public, or municipal corporation.

Pipelines are the piping, risers, and appurtenances installed for transporting oil, gas, sulphur, and produced waters.

Processed geological or geophysical information means data collected under a permit or a lease that have been processed or reprocessed. Processing involves changing the form of data 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. Reprocessing is the additional processing other than ordinary processing used in the general course of evaluation. Reprocessing operations may include varying identified parameters for the detailed study of a specific problem area.

Production means those activities that 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 workover operations.

Production areas are those areas where flammable petroleum gas, volatile liquids or sulphur are produced, processed (e.g., compressed), stored, transferred (e.g., pumped), or otherwise handled before entering the transportation process.

Projected emissions means emissions, either controlled or uncontrolled, from a source or sources.

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.

Right-of-use means any authorization issued under this part to use OCS lands.

Right-of-way pipelines are those pipelines that are contained within:

(1) The boundaries of a single lease or unit, but are not owned and operated by a lessee or operator of that lease or unit;

(2) The boundaries of contiguous (not cornering) leases that do not have a common lessee or operator;

(3) The boundaries of contiguous (not cornering) leases that have a common lessee or operator but are not owned and operated by that common lessee or operator; or

(4) An unleased block(s).

Routine operations, for the purposes of subpart F, means 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 that 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;

(12) Setting and retrieving other subsurface flow-control devices; and

(13) Acid treatments.

Sensitive reservoir means a reservoir in which high reservoir production rates will decrease ultimate recovery. For submitting the first MER, all oil reservoirs with an associated gas cap are classified as sensitive.

Significant archaeological resource means those archaeological resources that meet the criteria of significance for eligibility to the National Register of Historic Places as defined in 36 CFR 60.4, or its successor.

Suspension means a granted or directed deferral of the requirement to produce (Suspension of Production (SOP)) or to conduct leaseholding operations (Suspension of Operations (SOO)).

Waste of oil, gas, or sulphur means:

(1) The physical waste of oil, gas, or sulphur;

(2) The inefficient, excessive, or improper use, or the unnecessary dissipation of reservoir energy;

(3) The locating, spacing, drilling, equipping, operating, or producing of any oil, gas, or sulphur well(s) in a manner that causes or tends to cause a reduction in the quantity of oil, gas, or sulphur ultimately recoverable under prudent and proper operations or that causes or tends to cause unnecessary or excessive surface loss or destruction of oil or gas; or

(4) The inefficient storage of oil.

Welding means all activities connected with welding, including hot tapping and burning.

Wellbay is the area on a facility within the perimeter of the outermost wellheads.

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.

Western Gulf of Mexico means all OCS areas of the Gulf of Mexico except those the Director decides are adjacent to the State of Florida. The Western Gulf of Mexico is not the same as the Western Planning Area, an area established for OCS lease sales.

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.

You means a lessee, the owner or holder of operating rights, a designated agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement.

PERFORMANCE STANDARDS

§ 250.106 What standards will the Director use to regulate lease operations?

The Director will regulate all operations under a lease, right-of-use and easement, or right-of-way to:

(a) Promote orderly exploration, development, and production of mineral resources;

(b) Prevent injury or loss of life;

(c) Prevent damage to or waste of any natural resource, property, or the environment; and

(d) Cooperate and consult with affected States, local governments, other interested parties, and relevant Federal agencies.

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

(a) You must protect health, safety, property, and the environment by:

(1) Performing all operations in a safe and workmanlike manner; and

(2) Maintaining all equipment in a safe condition.

(b) You must immediately control, remove, or otherwise correct any hazardous oil and gas accumulation or other health, safety, or fire hazard.

(c) You must use the best available and safest technology (BAST) whenever practical on all exploration, development, and production operations. In general, we consider your compliance with MMS regulations to be the use of BAST.

(d) The Director may require additional measures to ensure the use of BAST:

(1) To avoid the failure of equipment that would have a significant effect on safety, health, or the environment;

(2) If it is economically feasible; and

(3) If the benefits outweigh the costs.

§ 250.108 What requirements must I follow for cranes and other material-handling equipment?

(a) If you operate a crane installed on fixed platforms you must:

(1) Follow the American Petroleum Institute (API) Recommended Practice (RP) for Operation and Maintenance of Offshore Cranes (API RP 2D);

(2) Keep inspection, testing, and maintenance records at the OCS facility for at least 2 years; and

(3) Keep crane operator qualifications at the facility for at least 4 years.

(b) You must operate and maintain all other material-handling equipment in a manner that ensures safe operations and prevents pollution.

§ 250.109 What documents must I prepare and maintain related to welding?

(a) You must submit a Welding Plan to the District Supervisor before you begin drilling or production activities on a lease. You may not begin welding until the District Supervisor has approved your plan.

(b) You must keep the following at the site where welding occurs:

(1) A copy of the plan and its approval letter; and

(2) Drawings showing the designated safe-welding areas.

§ 250.110 What must I include in my welding plan?

You must include all of the following in the Welding Plan that you prepare under § 250.109:

(a) Standards or requirements for welders;

(b) How you will ensure that only qualified personnel weld;

(c) Practices and procedures for safe welding that address:

(1) Welding in designated safe areas;

(2) Welding in undesignated areas, including wellbay;

(3) Fire watches;

(4) Maintenance of welding equipment; and

(5) Plans showing all designated safe-welding areas.

(d) How you will prevent spark-producing activities (i.e., grinding, abrasive blasting/cutting and arc-welding) in hazardous locations.

§ 250.111 Who oversees operations under my welding plan?

A welding supervisor or a designated person in charge must be thoroughly familiar with your welding plan. This person must ensure that each welder is properly qualified according to the welding plan. This person also must inspect all welding equipment before welding.

§ 250.112 What standards must my welding equipment meet?

Your welding equipment must meet the following requirements:

(a) All engine-driven welding equipment must be equipped with spark arrestors and drip pans;

(b) Welding leads must be completely insulated and in good condition;

(c) Hoses must be leak-free and equipped with proper fittings, gauges, and regulators; and

(d) Oxygen and fuel gas bottles must be secured in a safe place.

§ 250.113 What procedures must I follow when welding?

(a) Before you weld, you must move any equipment containing hydrocarbons or other flammable substances at least 35 feet horizontally from the welding area. You must move similar equipment on lower decks at least 35 feet from the point of impact where slag, sparks, or other burning materials could fall. If moving this equipment is impractical, you must protect that equipment with flame-proofed covers, shield it with metal or fire-resistant guards or curtains, or render the flammable substances inert.

(b) While you weld, you must monitor all water-discharge-point sources from hydrocarbon-handling vessels. If a discharge of flammable fluids occurs, you must stop welding.

(c) If you cannot weld in one of the designated safe-welding areas that you listed in your safe welding plan, you must meet the following requirements:

(1) You may not begin welding until:

(i) The welding supervisor or designated person in charge advises in writing that it is safe to weld.

(ii) You and the designated person in charge inspect the work area and areas below it for potential fire and explosion hazards.

(2) During welding, the person in charge must designate one or more persons as a fire watch. The fire watch must:

(i) Have no other duties while actual welding is in progress;

(ii) Have usable firefighting equipment;

(iii) Remain on duty for 30 minutes after welding activities end; and

(iv) Maintain a continuous surveillance with a portable gas detector during the welding and burning operation if welding occurs in an area not equipped with a gas detector.

(3) You may not weld piping, containers, tanks, or other vessels that have contained a flammable substance unless you have rendered the contents inert and the designated person in charge has determined it is safe to weld. This does not apply to approved hot taps.

(4) You may not weld within 10 feet of a wellbay unless you have shut in all producing wells in that wellbay.

(5) You may not weld within 10 feet of a production area, unless you have shut in that production area.

(6) You may not weld while you drill, complete, workover, or conduct wireline operations unless:

(i) The fluids in the well (being drilled, completed, worked over, or having wireline operations conducted) are noncombustible; and

(ii) You have precluded the entry of formation hydrocarbons into the wellbore by either mechanical means or a positive overbalance toward the formation.

§ 250.114 How must I install and operate electrical equipment?

The requirements in this section apply to all electrical equipment on all platforms, artificial islands, fixed structures, and their facilities.

(a) You must classify all areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2.

(b) Employees who maintain your electrical systems must have expertise in area classification and the performance, operation and hazards of electrical equipment.

(c) You must install all electrical systems according to API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms. You do not have to comply with Sections 7.4, Emergency Lighting, and 9.4, Aids to Navigation Equipment.

(d) On each engine that has an electric ignition system, you must use an ignition system designed and maintained to reduce the release of electrical energy.

[64 FR 72775, Dec. 28, 1999, as amended at 65 FR 219, Jan. 4, 2000]

§ 250.115 How do I determine well producibility?

You must follow the procedures in this section to determine well producibility if your well is not in the GOM. If your well is in the GOM you must follow the procedures in either this section or in § 250.116 of this subpart.

(a) You must write to the Regional Supervisor asking for permission to determine producibility.

(b) You must either:

(1) Allow the District Supervisor to witness each test that you conduct under this section; or

(2) Receive the District Supervisor's prior approval so that you can submit either test data with your affidavit or third party test data.

(c) If the well is an oil well, you must conduct a production test that lasts at least 2 hours after flow stabilizes.

(d) If the well is a gas well, you must conduct a deliverability test that lasts at least 2 hours after flow stabilizes, or a four-point back pressure test.

§ 250.116 How do I determine producibility if my well is in the Gulf of Mexico?

If your well is in the GOM, you must follow either the procedures in § 250.115 of this subpart or the procedures in this section to determine producibility.

(a) You must write to the Regional Supervisor asking for permission to determine producibility.

(b) You must provide or make available to the Regional Supervisor, as requested, the following log, core, analyses, and test criteria that MMS will consider collectively:

(1) A log showing sufficient porosity in the producible section.

(2) Sidewall cores and core analyses that show that the section is capable of producing oil or gas.

(3) Wireline formation test and/or mud-logging analyses that show that the section is capable of producing oil or gas.

(4) A resistivity or induction electric log of the well showing a minimum of 15 feet (true vertical thickness except for horizontal wells) of producible sand in one section.

(c) No section that you count as producible under paragraph (b)(4) of this section may include any interval that appears to be water saturated.

(d) Each section you count as producible under paragraph (b)(4) of this section must exhibit:

(1) A minimum true resistivity ratio of the producible section to the nearest clean or water-bearing sand of at least 5:1; and

(2) One of the following:

(i) Electrical spontaneous potential exceeding 20-negative millivolts beyond the shale baseline; or

(ii) Gamma ray log deflection of at least 70 percent of the maximum gamma ray deflection in the nearest clean water-bearing sand—if mud conditions prevent a 20-negative millivolt reading beyond the shale baseline.

§ 250.117 How does a determination of well producibility affect royalty status?

A determination of well producibility invokes minimum royalty status on the lease as provided in 30 CFR 202.53.

§ 250.118 Will MMS approve gas injection?

The Regional Supervisor may authorize you to inject gas on the OCS, on and off-lease, to promote conservation of natural resources and to prevent waste.

(a) To receive MMS approval for injection, you must:

(1) Show that the injection will not result in undue interference with operations under existing leases; and

(2) Submit a written application to the Regional Supervisor for injection of gas.

(b) The Regional Supervisor will approve gas injection applications that:

(1) Enhance recovery;

(2) Prevent flaring of casinghead gas; or

(3) Implement other conservation measures approved by the Regional Supervisor.

§ 250.119 Will MMS approve subsurface gas storage?

The Regional Supervisor may authorize subsurface storage of gas on the OCS, on and off-lease, for later commercial benefit. To receive MMS approval you must:

(a) Show that the subsurface storage of gas will not result in undue interference with operations under existing leases; and

(b) Sign a storage agreement that includes the required payment of a storage fee or rental.

§ 250.120 How does injecting, storing, or treating gas affect my royalty payments?

(a) If you produce gas from an OCS lease and inject it into a reservoir on the lease or unit for the purposes cited in § 250.118(b), you are not required to pay royalties until you remove or sell the gas from the reservoir.

(b) If you produce gas from an OCS lease and store it according to § 250.119, you must pay royalty before injecting it into the storage reservoir.

(c) If you produce gas from an OCS lease and treat it at an off-lease or off-unit location, you must pay royalties when the gas is first produced.

§ 250.121 What happens when the reservoir contains both original gas in place and injected gas?

If the reservoir contains both original gas in place and injected gas, when you produce gas from the reservoir you must use an MMS-approved formula to determine the amounts of injected or stored gas and gas original to the reservoir.

§ 250.122 What effect does subsurface storage have on the lease term?

If you use a lease area for subsurface storage of gas, it does not affect the continuance or expiration of the lease.

§ 250.123 Will MMS allow gas storage on unleased lands?

You may not store gas on unleased lands unless the Regional Supervisor approves a right-of-use and easement for that purpose, under §§ 250.160 through 250.166 of this subpart.

§ 250.124 Will MMS approve gas injection into the cap rock containing a sulphur deposit?

To receive the Regional Supervisor's approval to inject gas into the cap rock of a salt dome containing a sulphur deposit, you must show that the injection:

(a) Is necessary to recover oil and gas contained in the cap rock; and

(b) Will not significantly increase potential hazards to present or future sulphur mining operations.

INSPECTION OF OPERATIONS

§ 250.130 Why does MMS conduct inspections?

MMS will inspect OCS facilities and any vessels engaged in drilling or other downhole operations. These include facilities under jurisdiction of other Federal agencies that we inspect by agreement. We conduct these inspections:

(a) To verify that you are conducting operations according to the Act, the regulations, the lease, right-of-way, the approved Exploration Plan or Development and Production Plans; or right-of-use and easement, and other applicable laws and regulations; and

(b) To determine whether equipment designed to prevent or ameliorate blowouts, fires, spillages, or other major accidents has been installed and is operating properly according to the requirements of this part.

§ 250.131 Will MMS notify me before conducting an inspection?

MMS conducts both scheduled and unscheduled inspections.

§ 250.132 What must I do when MMS conducts an inspection?

(a) When MMS conducts an inspection, you must provide:

(1) Access to all platforms, artificial islands, and other installations on your leases or associated with your lease, right-of-use and easement, or right-of-way; and

(2) Helicopter landing sites and refueling facilities for any helicopters we use to regulate offshore operations.

(b) You must make the following available for us to inspect:

(1) The area covered under a lease, right-of-use and easement, right-of-way, or permit;

(2) All improvements, structures, and fixtures on these areas; and

(3) All records of design, construction, operation, maintenance, repairs, or investigations on or related to the area.

§ 250.133 Will MMS reimburse me for my expenses related to inspections?

Upon request, MMS will reimburse you for food, quarters, and transportation that you provide for MMS representatives while they inspect lease facilities and operations. You must send us your reimbursement request within 90 days of the inspection.

DISQUALIFICATION

§ 250.135 What will MMS do if my operating performance is unacceptable?

If your operating performance is unacceptable, MMS may disapprove or revoke your designation as operator on a single facility or multiple facilities. We will give you adequate notice and opportunity for a review by MMS officials before imposing a disqualification.

§ 250.136 How will MMS determine if my operating performance is unacceptable?

In determining if your operating performance is unacceptable, MMS will consider, individually or collectively:

(a) Accidents and their nature;

(b) Pollution events, environmental damages and their nature;

(c) Incidents of noncompliance;

(d) Civil penalties;

(e) Failure to adhere to OCS lease obligations; or

(f) Any other relevant factors.

SPECIAL TYPES OF APPROVALS

§ 250.140 When will I receive an oral approval?

When you apply for MMS approval of any activity, we normally give you a written decision. The following table shows circumstances under which we may give an oral approval.

When you	We may	And
(a) Request approval orally.	Give you an oral approval..	You must then confirm the oral request by sending us a written request within 72 hours.
(b) Request approval in writing.	Give you an oral approval if quick action is needed.	We will send you a written approval afterward. It will include any conditions that we place on the oral approval.
(c) Request approval orally for gas flaring.	Give you an oral approval..	You don't have to follow up with a written request unless the Regional Supervisor requires it. When you stop the approved flaring, you must promptly send a letter summarizing the location, dates and hours, and volumes of liquid hydrocarbons produced and gas flared by the approved flaring. (See 30 CFR 250, subpart K.)

§ 250.141 May I ever use alternate procedures or equipment?

You may use alternate procedures or equipment after receiving approval as described in this section.

(a) Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current MMS requirements.

(b) You must receive the District or Regional Supervisor's written approval before you can use alternate procedures or equipment.

(c) To receive approval, you must either submit information or give an oral presentation to the appropriate Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

§ 250.142 How do I receive approval for departures?

We may approve departures to the operating requirements. You may apply for a departure by writing to the District or Regional Supervisor.

[65 FR 6536, Feb. 10, 2000]

§ 250.143 How do I designate an operator?

(a) You must provide the Regional Supervisor an executed Designation of Operator form unless you are the only lessee and are the only person conducting lease operations. When there is more than one lessee, each lessee must submit the Designation of Operator form and the Regional Supervisor must approve the designation before the designated operator may begin operations on the leasehold.

(b) This designation is authority for the designated operator to act on your behalf and to fulfill your obligations under the Act, the lease, and the regulations in this part.

(c) You, or your designated operator, must immediately provide the Regional Supervisor a written notification of any change of address.

§ 250.144 How do I designate a new operator when a designation of operator terminates?

(a) When a Designation of Operator terminates, the Regional Supervisor must approve a new designated operator before you may continue operations. Each lessee must submit a new executed Designation of Operator form.

(b) If your Designation of Operator is terminated, or a controversy develops between you and your designated operator, you and your designated operator must protect the lessor's interests.

§ 250.145 How do I designate an agent or a local agent?

(a) You or your designated operator may designate for the Regional Supervisor's approval, or the Regional Director may require you to designate an agent empowered to fulfill your obligations under the Act, the lease, or the regulations in this part.

(b) You or your designated operator may designate for the Regional Supervisor's approval a local agent empowered to receive notices and submit requests, applications, notices, or supplemental information.

§ 250.146 Who is responsible for fulfilling leasehold obligations?

(a) When you are not the sole lessee, you and your co-lessee(s) are jointly and severally responsible for fulfilling your obligations under the provisions of 30 CFR parts 250 through 282, unless otherwise provided in these regulations.

(b) If your designated operator fails to fulfill any of your obligations under 30 CFR parts 250 through 282, the Regional Supervisor may require you or any or all of your co-lessees to fulfill those obligations or other operational obligations under the Act, the lease, or the regulations.

(c) Whenever the regulations in 30 CFR parts 250 through 282 require the lessee to meet a requirement or perform an action, the lessee, operator (if one has been designated), and the person actually performing the activity to which the requirement applies are jointly and severally responsible for complying with the regulation.

NAMING AND IDENTIFYING FACILITIES AND WELLS (DOES NOT INCLUDE MODUS)

§ 250.150 How do I name facilities and wells in the Gulf of Mexico Region?

(a) Assign each facility a letter designation except for those types of facilities identified in paragraph (c)(1) of this section. For example, A, B, CA, or CB.

(1) After a facility is installed, rename each predrilled well that was assigned only a number and was suspended temporarily at the mudline or at the surface. Use a letter and number designation. The letter used must be the same as that of the production facility, and the number used must correspond to the order in which the well was completed, not necessarily the number assigned when it was drilled. For example, the first well completed for production on Facility A would be renamed Well A–1, the second would be Well A–2, and so on; and

(2) When you have more than one facility on a block, each facility installed, and not bridge-connected to another facility, must be named using a different letter in sequential order. For example, EC 222A, EC 222B, EC 222C.

(3) When you have more than one facility on multiple blocks in a local area being co-developed, each facility installed and not connected with a walkway to another facility should be named using a different letter in sequential order with the block number corresponding to the block on which the platform is located. For example, EC 221A, EC 222B and EC 223C.

(b) In naming multiple well caissons, you must assign a letter designation.

(c) In naming single well caissons, you must use certain criteria as follows:

(1) For single well caissons not attached to a facility with a walkway, use the well designation. For example, Well No. 1;

(2) For single well caissons attached to a facility with a walkway, use the same designation as the facility. For example, rename Well No.10 as A–10; and

(3) For single well caissons with production equipment, use a letter designation for the facility name and a letter plus number designation for the well. For example, the Well No. 1 caisson would be designated as Facility A, and the well would be Well A–1.

§ 250.151 How do I name facilities in the Pacific Region?

The operator assigns a name to the facility.

§ 250.152 How do I name facilities in the Alaska Region?

Facilities will be named and identified according to the Regional Director's directions.

§ 250.153 Do I have to rename an existing facility or well?

You do not have to rename facilities installed and wells drilled before January 27, 2000, unless the Regional Director requires it.

§ 250.154 What identification signs must I display?

(a) You must identify all facilities, artificial islands, and mobile offshore drilling units with a sign maintained in a legible condition.

(1) You must display an identification sign that can be viewed from the waterline on at least one side of the platform. The sign must use at least 3-inch letters and figures.

(2) When helicopter landing facilities are present, you must display an additional identification sign that is visible from the air. The sign must use at least 12-inch letters and figures and must also display the weight capacity of the helipad unless noted on the top of the helipad. If this sign is visible to both helicopter and boat traffic, then the sign in paragraph (a)(1) of this section is not required.

(3) Your identification sign must:

(i) List the name of the lessee or designated operator;

(ii) In the GOM OCS Region, list the area designation or abbreviation and the block number of the facility location as depicted on OCS Official Protraction Diagrams or leasing maps;

(iii) In the Pacific OCS Region, list the lease number on which the facility is located; and

(iv) List the name of the platform, structure, artificial island, or mobile offshore drilling unit.

(b) You must identify singly completed wells and multiple completions as follows:

(1) For each singly completed well, list the lease number and well number on the wellhead or on a sign affixed to the wellhead;

(2) For wells with multiple completions, downhole splitter wells, and multilateral wells, identify each completion in addition to the well name and lease number individually on the well flowline at the wellhead; and

(3) For subsea wells that flow individually into separate pipelines, affix the required sign on the pipeline or surface flowline dedicated to that subsea well at a convenient location on the receiving platform. For multiple subsea wells that flow into a common pipeline or pipelines, no sign is required.

RIGHT-OF-USE AND EASEMENT

§ 250.160 When will MMS grant me a right-of-use and easement, and what requirements must I meet?

MMS may grant you a right-of-use and easement on leased and unleased lands on the OCS, if you meet these requirements:

(a) You must need the right-of-use and easement to construct and maintain platforms, artificial islands, and installations and other devices at an OCS site other than an OCS lease you own, that are:

(1) Permanently or temporarily attached to the seabed; and

(2) Used for conducting exploration, development, and production activities or other operations on or off lease; or

(3) Used for other purposes approved by MMS.

(b) You must exercise the right-of-use and easement according to the regulations of this part;

(c) You must meet the requirements at 30 CFR 256.35 (Qualification of lessees); establish a regional Company File as required by MMS; and must meet bonding requirements;

(d) If you apply for a right-of-use and easement on a leased area, you must notify the lessee and give her/him an opportunity to comment on your application; and

(e) You must receive MMS approval for all platforms, artificial islands, and installations and other devices permanently or temporarily attached to the seabed.

§ 250.161 What else must I submit with my application?

With your application, you must describe the proposed use giving:

(a) Details of the proposed uses and activities including access needs and special rights of use that you may need;

(b) A description of all facilities for which you are seeking authorization;

(c) A map or plat describing primary and alternate project locations; and

(d) A schedule for constructing any new facilities, drilling or completing any wells, anticipated production rates, and productive life of existing production facilities.

§ 250.162 May I continue my right-of-use and easement after the termination of any lease on which it is situated?

If your right-of-use and easement is on a lease, you may continue to exercise the right-of-use and easement after the lease on which it is situated terminates. You must only use the right-of-use and easement for the purpose that the grant specifies. All future lessees of that portion of the OCS on which your right-of-use and easement is situated must continue to recognize the right-of-use and easement for the purpose that the grant specifies.

§ 250.163 If I have a State lease, will MMS grant me a right-of-use and easement?

(a) MMS may grant a lessee of a State lease located adjacent to or accessible from the OCS a right-of-use and easement on the OCS.

(b) MMS will only grant a right-of-use and easement under this paragraph to enable a State lessee to conduct and maintain a device that is permanently or temporarily attached to the seabed (i.e., a platform, artificial island, or installation). The lessee must use the device to explore for, develop, and produce oil and gas from the adjacent or accessible State lease and for other operations related to these activities.

§250.164 If I have a State lease, what conditions apply for a right-of-use and easement?

(a) A right-of-use and easement granted under the heading of ''Right-of-use and easement'' in this subpart is subject to MMS regulations, 30 CFR parts 250 through 282, and any terms and conditions that the Regional Director prescribes.

(b) For the whole or fraction of the first calendar year, and annually after that, you must pay to MMS, in advance, an annual rental payment.

§250.165 If I have a State lease, what fees do I have to pay for a right-of-use and easement?

When you apply for a right-of-use and easement, you must pay:

(a) A nonrefundable filing fee as specified in §0.1010(a); and

(b) The first year's rental as specified in §250.1009(c)(2).

§250.166 If I have a State lease, what surety bond must I have for a right-of-use and easement?

(a) Before MMS issues you a right-of-use and easement on the OCS, you must furnish the Regional Director a surety bond for $500,000.

(b) The Regional Director may require additional security from you (i.e., security above the prescribed $500,000) to cover additional costs and liabilities for regulatory compliance. This additional surety:

(1) Must be in the form of a supplemental bond or bonds meeting the requirements of §256.54 (General requirements for bonds) or an increase in the coverage of an existing surety bond.

(2) Covers additional costs and liabilities for regulatory compliance, including well abandonment, platform and structure removal, and site clearance from the seafloor of the right-of-use and easement.

SUSPENSIONS

§250.168 May operations or production be suspended?

(a) You may request approval of a suspension, or the Regional Supervisor may direct a suspension (Directed Suspension), for all or any part of a lease or unit area.

(b) Depending on the nature of the suspended activity, suspensions are labeled either Suspensions of Operations (SOO) or Suspensions of Production (SOP).

§250.169 What effect does suspension have on my lease?

(a) A suspension may extend the term of a lease (see §250.180(b)). The extension is equal to the length of time the suspension is in effect, except as provided in paragraph (b) of this section.

(b) A Directed Suspension does not extend the term of a lease when the Regional Supervisor *directs* a suspension because of:

(1) Gross negligence; or

(2) A willful violation of a provision of the lease or governing statutes and regulations.

§250.170 How long does a suspension last?

(a) MMS may issue suspensions for up to 5 years per suspension. The Regional Supervisor will set the length of the suspension based on the conditions of the individual case involved. MMS may grant consecutive suspension periods.

(b) An SOO ends automatically when the suspended operation commences.

(c) An SOP ends automatically when production begins.

(d) A Directed Suspension normally ends as specified in the letter directing the suspension.

(e) MMS may terminate any suspension when the Regional Supervisor determines the circumstances that justified the suspension no longer exist or that other lease conditions warrant termination. The Regional Supervisor will notify you of the reasons for termination and the effective date.

§250.171 How do I request a suspension?

You must submit your request for a suspension to the Regional Supervisor, and MMS must receive the request before the end of the lease term (i.e., end of primary term, end of the 180-day period following the last leaseholding operation, and end of a current suspension).

(a) The justification for the suspension including the length of suspension requested;

(b) A reasonable schedule of work leading to the commencement or restoration of the suspended activity;

(c) A statement that a well has been drilled on the lease and determined to be producible according to §§ 250.115, 250.116, or 250.1603 (SOP only); and

(d) A commitment to production (SOP only).

§ 250.172 When may the Regional Supervisor grant or direct an SOO or SOP?

The Regional Supervisor may grant or direct an SOO or SOP under any of the following circumstances:

(a) When necessary to comply with judicial decrees prohibiting any activities or the permitting of those activities. The effective date of the suspension will be the effective date required by the action of the court;

(b) When activities pose a threat of serious, irreparable, or immediate harm or damage. This would include a threat to life (including fish and other aquatic life), property, any mineral deposit, or the marine, coastal, or human environment. MMS may require you to do a site-specific study. (See § 250.177(a).)

(c) When necessary for the installation of safety or environmental protection equipment;

(d) When necessary to carry out the requirements of NEPA or to conduct an environmental analysis; or

(e) When necessary to allow for inordinate delays encountered in obtaining required permits or consents, including administrative or judicial challenges or appeals.

§ 250.173 When may the Regional Supervisor direct an SOO or SOP?

The Regional Supervisor may direct a suspension when:

(a) You failed to comply with an applicable law, regulation, order, or provision of a lease or permit; or

(b) The suspension is in the interest of national security or defense.

§ 250.174 When may the Regional Supervisor grant or direct an SOP?

The Regional Supervisor may grant or direct an SOP when the suspension is in the national interest, and it is necessary because the suspension will meet one of the following criteria:

(a) It will allow you to properly develop a lease, including time to construct and install production facilities;

(b) It will allow you time to obtain adequate transportation facilities;

(c) It will allow you time to enter a sales contract for oil, gas, or sulphur. You must show that you are making an effort to enter into the contract(s); or

(d) It will avoid continued operations that would result in premature abandonment of a producing well(s).

§ 250.175 When may the Regional Supervisor grant an SOO?

The Regional Supervisor may grant an SOO when necessary to allow you time to begin drilling or other operations when you are prevented by reasons beyond your control, such as unexpected weather, unavoidable accidents, or drilling rig delays.

§ 250.176 Does a suspension affect my royalty payment?

A directed suspension may affect the payment of rental or royalties for the lease as provided in § 218.154.

§ 250.177 What additional requirements may the Regional Supervisor order for a suspension?

If MMS grants or directs a suspension under paragraph § 250.172(b), the Regional Supervisor may require you to:

(a) Conduct a site-specific study.

(1) The Regional Supervisor must approve or prescribe the scope for any site-specific study that you perform.

(2) The study must evaluate the cause of the hazard, the potential damage, and the available mitigation measures.

(3) You must pay for the study unless you request, and the Regional Supervisor agrees to arrange, payment by another party.

(4) You must furnish copies and results of the study to the Regional Supervisor.

(5) MMS will make the results available to other interested parties and to the public.

(6) The Regional Supervisor will use the results of the study and any other information that becomes available:

(i) To decide if the suspension can be lifted; and

(ii) To determine any actions that you must take to mitigate or avoid any damage to the environment, life, or property.

(b) Submit a revised Exploration Plan (including any required mitigating measures);

(c) Submit a revised Development and Production Plan (including any required mitigating measures); or

(d) Submit a revised Development Operations Coordination Document according to 30 CFR Part 250, subpart B.

PRIMARY LEASE REQUIREMENTS, LEASE TERM EXTENSIONS, AND LEASE CANCELLATIONS

§ 250.180 What am I required to do to keep my lease term in effect?

(a) If your lease is in its primary term:

(1) You must submit a report to the District Supervisor according to paragraphs (h) and (i) of this section whenever production begins initially, whenever production ceases during the last 180 days of the primary term, and whenever production resumes during the last 180 days of the primary term.

(2) Your lease expires at the end of its primary term unless you are conducting operations on your lease (see 30 CFR part 256). For purposes of this section, the term *operations* means, drilling, well-reworking, or production in paying quantities. The objective of the drilling or well-reworking must be to establish production in paying quantities on the lease.

(b) If you stop conducting operations during the last 180 days of your primary lease term, your lease will expire unless you either resume operations or receive an SOO or an SOP from the Regional Supervisor under §§ 250.172, 250.173, 250.174, or 250.175 before the end of the 180th day after you stop operations.

(c) If you extend your lease term under paragraph (b) of this section, you must pay rental or minimum royalty, as appropriate, for each year or part of the year during which your lease continues in force beyond the end of the primary lease term.

(d) If you stop conducting operations on a lease that has continued beyond its primary term, your lease will expire unless you resume operations or receive an SOO or an SOP from the Regional Supervisor under § 250.172, 250.173, 250.174, or 250.175 before the end of the 180th day after you stop operations.

(e) You may ask the Regional Supervisor to allow you more than 180 days to resume operations on a lease continued beyond its primary term when operating conditions warrant. The request must be in writing and explain the operating conditions that warrant a longer period. In allowing additional time, the Regional Supervisor must determine that the longer period is in the national interest, and it conserves resources, prevents waste, or protects correlative rights.

(f) When you begin conducting operations on a lease that has continued beyond its primary term, you must immediately notify the District Supervisor either orally or by fax or e-mail and follow up with a written report according to paragraph (g) of this section.

(g) If your lease is continued beyond its primary term, you must submit a report to the District Supervisor under paragraphs (h) and (i) of this section whenever production begins initially, whenever production ceases, whenever production resumes before the end of the 180-day period after having ceased, or whenever drilling or well-reworking operations begin before the end of the 180-day period.

(h) The reports required by paragraphs (a) and (g) of this section must contain:

(1) Name of lessee or operator;

(2) The well number, lease number, area, and block;

(3) As appropriate, the unit agreement name and number; and

(4) A description of the operation and pertinent dates.

(i) You must submit the reports required by paragraphs (a) and (g) of this section within the following timeframes:

(1) Initialization of production—within 5 days of initial production.

(2) Cessation of production—within 15 days after the first full month of zero production.

(3) Resumption of production—within 5 days of resuming production after ceasing production under paragraph (i)(2) of this section.

(4) Drilling or well reworking operations—within 5 days of beginning and completing the leaseholding operations.

(j) For leases continued beyond the primary term, you must immediately report to the District Supervisor if operations do not begin before the end of the 180-day period.

§ 250.181 When may the Secretary cancel my lease and when am I compensated for cancellation?

If the Secretary cancels your lease under this part or under 30 CFR part 256, you are entitled to compensation under § 250.184. Section 250.185 states conditions under which you will receive *no* compensation. The Secretary may cancel a lease after notice and opportunity for a hearing when:

(a) Continued activity on the lease would probably cause harm or damage to life (including fish and other aquatic life), property, any mineral deposits (in areas leased or not leased), or the marine, coastal, or human environment;

(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 cancellation outweigh the advantages of continuing the lease in force; and (d) A suspension has been in effect for at least 5 years or you request termination of the suspension and lease cancellation.

§ 250.182 When may the Secretary cancel a lease at the exploration stage?

MMS may not approve an exploration plan (EP) under 30 CFR part 250, subpart B, if the Regional Supervisor determines that the proposed activities may cause serious harm or damage to life (including fish and other aquatic life), property, any mineral deposits, the national security or defense, or to the marine, coastal, or human environment, and that the proposed activity cannot be modified to avoid the condition(s). The Secretary may cancel the lease if:

(a) The primary lease term has not expired (or if the lease term has been extended) and exploration has been prohibited for 5 years following the disapproval; or

(b) You request cancellation at an earlier time.

§ 250.183 When may MMS or the Secretary extend or cancel a lease at the development and production stage?

(a) MMS may extend your lease if you submit a DPP and the Regional Supervisor disapproves the plan according to the regulations in 30 CFR part 250, subpart B. Following the disapproval:

(1) MMS will allow you to hold the lease for 5 years, or less time at your request;

(2) Any time within 5 years after the disapproval, you may reapply for approval of the same or a modified plan; and

(3) The Regional Supervisor will approve, disapprove, or require modification of the plan under 30 CFR part 250, subpart B.

(b) If the Regional Supervisor has not approved a DPP or required you to submit a DPP for approval or modification, the Secretary will cancel the lease:

(1) When the 5-year period in paragraph (a)(1) of this section expires; or

(2) If you request cancellation at an earlier time.

§ 250.184 What is the amount of compensation for lease cancellation?

When the Secretary cancels a lease under §§ 250.181, 250.182 or 250.183 of this subpart, you are entitled to receive compensation under 43 U.S.C. 1334 (a)(2)(C). You must show the Director that the amount of compensation claimed is the lesser of paragraph (a) or (b) of this section:

(a) The fair value of the cancelled rights as of the date of cancellation, taking into account both:

(1) Anticipated revenues from the lease; and

(2) Costs reasonably anticipated on the lease, including:

(i) Costs of compliance with all applicable regulations and operating orders; and

(ii) Liability for cleanup costs or damages, or both, in the case of an oil spill.

(b) The excess, if any, over your revenues from the lease (plus interest thereon from the date of receipt to date of reimbursement) of:

(1) All consideration paid for the lease (plus interest from the date of payment to the date of reimbursement); and

(2) All your direct expenditures (plus interest from the date of payment to the date of reimbursement):

(i) After the issue date of the lease; and

(ii) For exploration or development, or both.

(c) Compensation for leases issued before September 18, 1978, will be equal to the amount specified in paragraph (a) of this section.

§250.185 When is there no compensation for a lease cancellation?

You will not receive compensation from MMS for lease cancellation if:

(a) MMS disapproves a DPP because you do not receive concurrence by the State under 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;

(b) You do not submit a DPP under 30 CFR part 250, subpart B or do not comply with the approved DPP;

(c) As the lessee of a nonproducing lease, you fail to comply with the Act, the lease, or the regulations issued under the Act, and the default continues for 30 days after MMS mails you a notice by overnight mail;

(d) The Regional Supervisor disapproves a DPP because you fail to comply with the requirements of applicable Federal law; or

(e) The Secretary forfeits and cancels a producing lease under section 5(d) of the Act (43 U.S.C. 1334(d)).

Information and Reporting Requirements

§250.190 What reporting information and report forms must I submit?

(a) You must submit information and reports as MMS requires.

(1) You may obtain copies of forms from, and submit completed forms to, the Regional or District Supervisor.

(2) Instead of paper copies of forms available from the Regional or District Supervisor, you may use your own computer-generated forms that are equal in size to MMS's forms. You must arrange the data on your form identical to the MMS form. If you generate your own form and it omits terms and conditions contained on the official MMS form, we will consider it to contain the omitted terms and conditions.

(3) You may submit digital data when the Region/District is equipped to accept it.

(b) When MMS specifies, you must include, for public information, an additional copy of such reports.

(1) You must mark it *Public Information*.

(2) You must include all required information, except information exempt from public disclosure under §250.196 or otherwise exempt from public disclosure under law or regulation.

§250.191 What accident reports must I submit?

(a) You must 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. You must report all spills of oil or other liquid pollutants according to 30 CFR part 254.

(b) If you hold an easement, right-of-way, or other permit, and your operation is related to the exercise of the easement, right-of-way, or other permit, you must comply with paragraph (a) by notifying and reporting to the Regional Supervisor any accidents occurring on the area covered by the easement, right-of-way, or other permit.

(c) Any investigation that the Secretary or the U.S. Coast Guard (USCG) conducts under the authority of sections 22(d)(1) and (2) of the Act (43 U.S.C. 1348 d(1) and (2)), is a fact-finding proceeding with no civil or criminal issues and no adverse parties. The purpose of the investigation is to prepare a public report that determines the cause or causes of the accident. The investigation may involve panel meetings conducted by a chairperson appointed by MMS. The following requirements must be met for any panel meetings involving persons giving testimony:

(1) A person giving testimony may have legal and/or other representative(s) present to provide advice or counsel while the person is giving testimony. The chairperson may require a verbatim transcript to be made of all oral testimony. The chairperson also may accept a sworn written statement in lieu of oral testimony.

(2) Only panel members, panel's legal advisors, and any experts the panel deems necessary may address questions to any person giving testimony.

(3) The chairperson may issue subpoenas to persons to appear and provide testimony and/or documents at a panel meeting. A subpoena may not require a person to attend a panel meeting held at a location more than 100 miles from where a subpoena is served.

(4) Any person giving testimony may request compensation for mileage and fees for service within 90 days after the panel meeting. The compensated expenses must be similar to mileage and fees the U.S. District Courts allow.

§ 250.192 What evacuation statistics must I submit?

You must submit evacuation statistics to the Regional Supervisor for a natural occurrence such as an earthquake or hurricane. MMS will notify local and national authorities and the public, as appropriate. Statistics include facilities and rigs evacuated and amount of production shut-in for gas and oil. You must:

(a) Submit the statistics by fax or e-mail as soon as possible when evacuation occurs;

(b) Submit statistics on a daily basis by 11:00 a.m., as conditions allow, during the period of shut-in and evacuation;

(c) Inform MMS when you resume production; and

(d) Submit statistics either by MMS district or the total figures for your operations in the Region.

§ 250.193 Reports and investigations of apparent violations.

Any person may report to MMS an apparent violation or failure to comply with any provision of the Act, any provision of a lease, license, or permit issued under the Act, or any provision of any regulation or order issued under the Act. When MMS receives a report of an apparent violation, or when an MMS employee detects an apparent violation after making an initial determination of the validity, MMS will investigate according to MMS procedures.

§ 250.194 What archaeological reports and surveys must I submit?

(a) If it is likely that an archaeological resource exists in the lease area, the Regional Director will notify you in writing. You must include an archaeological report in the EP or DPP. If the archaeological report suggests that an archaeological resource may be present, you must either:

(1) Locate the site of any operation so as not to adversely affect the area where the archaeological resource may be; or

(2) Establish to the satisfaction of the Regional Director that an archaeological resource does not exist or will not be adversely affected by operations. This requires further archaeological investigation, conducted by an archaeologist and a geophysicist, using survey equipment and techniques the Regional Director considers appropriate. You must submit the investigation report to the Regional Director for review.

(b) If the Regional Director determines that an archaeological resource is likely to be present in the lease area and may be adversely affected by operations, the Regional Director will notify you immediately. You must not take any action that may adversely affect the archaeological resource until the Regional Director has told you how to protect the resource.

(c) If you discover any archaeological resource while conducting operations in the lease area, you must immediately halt operations within the area of the discovery and report the discovery to the Regional Director. If investigations determine that the resource is significant, the Regional Director will tell you how to protect it.

§ 250.195 Reimbursements for reproduction and processing costs.

(a) MMS will reimburse you for costs of reproducing data and information that the Regional Director requests if:

(1) You deliver geophysical and geological (G&G) data and information to MMS for the Regional Director to inspect or select and retain;

(2) MMS receives your request for reimbursement and the Regional Director determines that the requested reimbursement is proper; and

(3) The cost is at your lowest rate or at the lowest commercial rate established in the area, whichever is less.

(b) MMS will reimburse you for the costs of processing geophysical information (that does not include cost of data acquisition):

(1) If, at the request of the Regional Director, you processed the geophysical data or information in a form or manner other than that used in the normal conduct of business; or

(2) If you collected the information under a permit that MMS issued to you before October 1, 1985, and the Regional Director requests and retains the information.

(c) When you request reimbursement, you must identify reproduction and processing costs separately from acquisition costs.

(d) MMS will not reimburse you for data acquisition costs or for the costs of analyzing or processing geological information or interpreting geological or geophysical information.

§ 250.196 Data and information to be made available to the public.

MMS will protect data and information you submit under this part, as described in this section. The tables in paragraphs (a) and (b) of this section describe what data and information will be made available to the public without the consent of the lessee and under what circumstances and in what time period.

(a) MMS will disclose data and information you submit on MMS forms according to the following table:

Data and information that you submit on form	In the following items	Will be released	And
(1) MMS–123, Application for Permit to Drill.	All entries except items 17, 24, and 25.	At any time	The data and information in items 17, 24, and 25 will be released according to the table in paragraph (b) of this section or when the well goes on production, whichever is earlier.
(2) MMS–124, Sundry Notices and Reports on Wells.	All entries except item 36.	At any time	The data and information in item 36 will be released according to the table in paragraph (b) or when the well goes on production, whichever is earlier.
(3) MMS–125, Well Summary Report.	All entries except items 17, 24, 34, 37, and 46 through 87.	At any time	The data and information in the excepted items will be released according to the table in paragraph (b) of this section or when the well goes on production, whichever is earlier. However, items 78 through 87 will not be released when the well goes on production unless the period of time in the table in paragraph (b) has expired
(4) MMS–126, Well Potential Test Report.	All entries except item 101.	When the well goes on production.	The data and information in item 101 will be released 2 years after you submit it.
(5) MMS–127, Request for Reservoir Maximum Efficient Rate (MER).	All entries except items 124 through 168.	At any time	The data and information in items 124 through 168 will be released according to the time periods in the table in paragraph (b) of this section.
(6) MMS–128, Semiannual Well Test Report.	All entries	At any time.	

(b) MMS will disclose lease data and information that you submit, but that are not usually submitted on MMS forms, according to the following table:

If	MMS will release	At this time	Special provisions
(1) The Director determines that data and information are needed to unitize operations on two or more leases, to determine whether a reservoir is competitive to ensure proper plans of development for competitive reservoirs, or to promote operational safety or protect the environment.	Geophysical data, Geological data, Interpreted (G&G) information, Processed G&G information, Analyzed geological information.	At any time	Data and information will be shown only to persons with an interest in the issue.
(2) The Director determines that data and information are needed for specific scientific or research purposes for the Government.	Geophysical data, Geological data Interpreted G&G information, Processed G&G information, Analyzed geological information.	At any time	MMS will release data and information only if release would further the national interest without unduly damaging the competitive position of the lessee.
(3) Data or information is collected with high-resolution systems (e.g., bathymetry, side-scan sonar, subbottom profiler, and magnetometer) to comply with safety or environmental protection requirements.	Geophysical data, Geological data, Interpreted G&G information, Processed geological information, Analyzed geological information.	60 days after MMS receives the data or information, if the Regional Supervisor deems it necessary.	MMS will release the data and information earlier than 60 days if the Regional Supervisor determines it is needed by affected States to make decisions under subpart B. The Regional Supervisor will reconsider earlier release if you satisfy him/her that it would unduly damage your competitive position.
(4) Your lease is no longer in effect	Geophysical data, Geological data, Processed G&G information Interpreted G&G information, Analyzed geological information.	When your lease terminates.	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in § 252.7 do not apply. The release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(5) Your lease is still in effect	Geophysical data Processed geophysical information, Interpreted G&G information.	10 years after you submit the data and information.	This release time applies only if the provisions in this table governing high-resolution systems and the provisions in § 252.7 do not apply. This release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(6) Your lease is still in effect and within the primary term specified in the lease.	Geological data, Analyzed geological information.	2 years after the required submittal date or 60 days after a lease sale if any portion of an offered lease is within 50 miles of a well, whichever is later.	These release times apply only if the provisions in this table governing high-resolution systems and the provisions in § 252.7 do not apply. If the primary term specified in the lease is extended under the heading of ''Suspensions'' in this subpart, the extension applies to this provision.
(7) Your lease is in effect and beyond the primary term specified in the lease.	Geological data, Analyzed geological information.	2 years after the required submittal date.	None.
(8) Data is released to the owner of an adjacent lease under subpart D of part 250.	Directional survey data.	If the lessee from whose lease the directional survey was taken consents.	None.
(9) Data and information are obtained from beneath unleased land as a result of a well deviation that has not been approved by the Regional or District Supervisor.	Any data or information obtained.	At any time	None.
(10) Data and information acquired by a permit under part 251 is submitted by a lessee under part 250.	Geophysical data, Processed geophysical information, Interpreted geophysical information.	Geophysical data: 50 years, Geophysical information: 25 years after you submit it.	None.

REFERENCES

§ 250.198 Documents incorporated by reference.

(a) MMS is incorporating by reference the documents listed in the table in paragraph (e) of this section. The Director of the Federal Register has approved this incorporation by reference according to 5 U.S.C. 552(a) and 1 CFR part 51.

(1) MMS will publish any changes to these documents in the FEDERAL REGISTER.

(2) MMS may make the rule amending the document effective without prior opportunity for public comment when MMS determines:

(i) That the revisions to a document result in safety improvements or represent new industry standard technology and do not impose undue costs on the affected parties; and

(ii) MMS meets the requirements for making a rule immediately effective under 5 U.S.C. 553.

(b) MMS incorporated each document or specific portion by reference in the sections noted. The entire document is incorporated by reference, unless the text of the corresponding sections in this part 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 or addendum cited in this section.

(c) Under §§ 250.141 and 250.142, you may comply with a later edition of a specific document incorporated by reference, provided:

(1) You show that complying with the later edition provides a degree of protection, safety, or performance equal to or better than would be achieved by compliance with the listed edition; and

(2) You obtain the prior written approval for alternative compliance from the authorized MMS official.

(d) You may inspect these documents at the Minerals Management Service, 381 Elden Street, Room 3313, Herndon, Virginia; or at the Office of the FEDERAL REGISTER, 800 North Capitol Street, NW., Suite 700, Washington, DC. You may obtain the documents from the publishing organizations at the addresses given in the following table:

For	Write to
ACI Standards	American Concrete Institute, P. O. Box 19150, Detroit, MI 48219.
AISC Standards	American Institute of Steel Construction, Inc., P.O. Box 4588, Chicago, IL 60680.
ANSI/ASME Codes	American National Standards Institute, Attention Sales Department, 1430 Broadway, New York, NY 10018; and/or American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, NY 10017.
API Recommended Practices, Specs, Standards, Manual of Petroleum Measurement Standards (MPMS) chapters.	American Petroleum Institute, 1220 L Street, NW., Washington, DC 20005–4070.
ASTM Standards	American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959.
AWS Codes	American Welding Society, 550 NW, LeJeune Road, P.O. Box 351040, Miami, FL 33135.
NACE Standards	National Association of Corrosion Engineers, P.O. Box 218340, Houston, TX 77218.

(e) This paragraph lists documents incorporated by reference. To easily reference text of the corresponding sections with the list of documents incorporated by reference, the list is in alphanumerical order by organization and document.

Title of documents	Incorporated by reference at
ACI Standard 318–95, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–95).	§ 250.908(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), (e)(2)(i).
ACI Standard 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984.	§ 250.900(g); § 250.908(c)(2), (c)(3).
AISC Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, June 1, 1989, with Commentary.	§ 250.907(b)(1)(ii), (c)(4)(ii), (c)(4)(vii).

Title of documents	Incorporated by reference at
ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers, including Appendices, 1998 Edition; July 1, 1999 Addenda, Rules for Construction of Power Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Power Boilers; and all Section I Interpretations Volume 43.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers, including Nonmandatory Appendices A, B, C, D, E, F, H, I, K, and L, and the Guide to Manufacturers Data Report Forms, 1998 Edition; July 1, 1999 Addenda, Rules for Construction of Heating Boilers, by ASME Boiler and Pressure Vessel Committee Subcommittee on Heating Boilers; and all Section IV Interpretations Volumes 43 and 44.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels, Divisions 1 and 2, including Nonmandatory Appendices, 1998 Edition; July 1, 1999 Addenda, Rules for Construction of Pressure Vessels, by ASME Boiler and Pressure Vessel Committee Subcommittee on Pressure Vessels; and all Section VIII Interpretations, Divisions 1 and 2, Volumes 43 and 44.	§ 250.803(b)(1), (b)(1)(i); § 250.1629(b)(1), (b)(1)(i).
ANSI/ASME B 16.5–1988 (including Errata) and B 16.5a–1992 Addenda, Pipe Flanges and Flanged Fittings.	§ 250.1002(b)(2).
ANSI/ASME B 31.8–1995, Gas Transmission and Distribution Piping Systems	§ 250.1002(a).
ANSI/ASME SPPE–1–1994 and SPPE–1d–1996 ADDENDA, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations.	§ 250.806(a)(2)(i).
ANSI Z88.2–1992, American National Standard for Respiratory Protection	§ 250.417(g)(4)(iv), (j)(13)(ii).
API MPMS, Chapter 1, Vocabulary, Second Edition, July 1994, API Stock No., H01002.	§ 250.1201.
API MPMS, Chapter 2, Tank Calibration, Section 2A, Measurement and Calibration of Upright Cylindrical Tanks by the Manual Strapping Method, First Edition, February 1995, API Stock No. H022A1.	§ 250.1202(l)(4).
API MPMS, Chapter 2, Section 2B, Calibration § 250.1202(l)(4) Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989, reaffirmed May 1996, API Stock No. H30023; also available as ANSI/ASTM D 4738–88.	250.1202(l)(4).
API MPMS, Chapter 3, Tank Gauging, Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, First Edition, December 1994, API Stock No. H031A1.	§ 250.1202(l)(4).
API MPMS, Chapter 3, Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, First Edition, April 1992, reaffirmed January 1997, API Stock No. H30060.	§ 250.1202(l)(4).
API MPMS, Chapter 4, Proving Systems, Section 1, Introduction, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30081.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4, Section 2, Conventional Pipe Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30082.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4, Section 3, Small Volume Provers, First Edition, July 1988, reaffirmed October 1993, API Stock No. H30083.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4, Section 4, Tank Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30084.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4, Section 5, Master-Meter Provers, First Edition, October 1988, reaffirmed October 1993, API Stock No. H30085.	§ 250.1202(a)(3), (f)(1).
API MPMS, Chapter 4, Section 6, Pulse Interpolation, Second Edition, May 1999, API Stock No. H04062.	§ 250.1202(a)(3) and (f)(1).
API MPMS, Chapter 4, Section 7, Field Standard Test Measures, Second Edition, December 1998, API Stock No. H04072.	§ 250.1202(a)(3) and (f)(1).
API MPMS, Chapter 5, Metering, Section 1, General Considerations for Measurement by Meters, Third Edition, September 1995, API Stock No. H05013.	§ 250.1202(a)(3).
API MPMS, Chapter 5, Section 2, Measurement of Liquid Hydrocarbons by Displacement Meters, Second Edition, November 1987, reaffirmed January 1997, API Stock No. H30102.	§ 250.1202(a)(3).
API MPMS, Chapter 5, Section 3, Measurement of Liquid Hydrocarbons by Turbine Meters, Third Edition, September 1995, API Stock No. H05033.	§ 250.1202(a)(3).
API MPMS, Chapter 5, Section 4, Accessory Equipment for Liquid Meters, Third Edition, September 1995, with Errata, March 1996, API Stock No. H05043.	§ 250.1202(a)(3).
API MPMS, Chapter 5, Section 5, Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, First Edition, June 1982, reaffirmed January 1997, API Stock No. H30105.	§ 250.1202(a)(3).
API MPMS, Chapter 6, Metering Assemblies, Section 1, Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991, reaffirmed July 1996, API Stock No. H30121.	§ 250.1202(a)(3).
API MPMS, Chapter 6, Section 6, Pipeline Metering Systems, Second Edition, May 1991, reaffirmed July 1996, API Stock No. H30126.	§ 250.1202(a)(3).
API MPMS, Chapter 6, Section 7, Metering Viscous Hydrocarbons, Sescond Edition, May 1991, reaffirmed July 1996, API Stock No. H30127.	§ 250.1202(a)(3).
API MPMS, Chapter 7, Temperature Determination, Section 2, Dynamic Temperature Determination, Second Edition, March 1995, API Stock No. H07022.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 7, Section 3, Static Temperature Determination Using Portable Electronic Thermometers, First Edition, July 1985, reaffirmed May 1996, API Stock No. H30143.	§ 250.1202(a)(3), (l)(4).

Title of documents	Incorporated by reference at
API MPMS, Chapter 8, Sampling, Section 1, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; also available as ANSI/ASTM D 4057–88, API Stock No. H30161.	§ 250.1202(b)(4)(i), (l)(4).
API MPMS, Chapter 8, Section 2, Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; also available as ANSI/ASTM D 4177, API Stock No. H30162.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 9, Density Determination, Section 1, Hydrometer Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products, First Edition, June 1981, reaffirmed December 1998, API Stock No. H30181; also available as ANSI/ASTM D 1298.	§ 250.1202(a)(3) and (l)(4).
API MPMS, Chapter 9, Section 2, Pressure Hydrometer Test Method for Density or Relative Density, First Edition, April 1982, reaffirmed December 1998, API Stock No. H30182.	§ 250.1202(a)(3) and (l)(4).
API MPMS, Chapter 10, Sediment and Water, Section 1, Determination of Sediment in Crude Oils and Fuel Oils by the Extraction Method, First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 473, API Stock No. H30201.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10, Section 2, Determination of Water in Crude Oil by Distillation Method, First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 4006, API Stock No. H30202.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10, Section 3, Determination of Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), First Edition, April 1981, reaffirmed December 1993; also available as ANSI/ASTM D 4007, API Stock No. H30203.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 10, Section 4, Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure), Second Edition, May 1988, reaffirmed May 1998; also available as ANSI/ASTM D 96, API Stock No. H30204.	§ 250.1202(a)(3), (l)(4).
API MPMS, Chapter 11.1, Volume Correction Factors, Volume 1, 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 60°F, First Edition, August 1980, reaffirmed March 1997, API Stock No. H27000; also available as ANSI/ASTM D 1250.	§ 250.1202(a)(3), (g)(3) and (l)(4).
API MPMS, Chapter 11.2.1, Compressibility Factors for Hydrocarbons: 0–90° API Gravity Range, First Edition, August 1984, reaffirmed May 1996, API Stock No. H27300.	§ 250.1202(a)(3), (g)(4).
API MPMS, 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, reaffirmed March 1997, API Stock No. H27307; also available as Gas Processors Association (GPA) 8286.	§ 250.1202(a)(3) and (g)(4).
API MPMS, Chapter 11, Physical Properties Data, Addendum to Section 2.2, Compressibility Factors for Hydrocarbons, Correlation of Vapor Pressure for Commercial Natural Gas Liquids, First Edition, December 1994, reaffirmed March 1997; also available as GPA TP–15, API Stock No. H27308.	§ 250.1202(a)(3).
API MPMS, Chapter 11.2.3, Water Calibration of Volumetric Provers, First Edition, August 1984, reaffirmed, May 1996, API Stock No. H27310.	§ 250.1202(f)(1).
API MPMS, Chapter 12, Calculation of Petroleum Quantities, Section 2, Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Including Parts 1 and 2, Second Edition, May 1995; also available as ANSI/API MPMS 12.2–1981, API Stock No. H30302.	§ 250.1202(a)(3), (g)(1), (g)(2).
API MPMS, Chapter 14, Natural Gas Fluids Measurement, Section 3, Concentric Square-Edged Orifice Meters, Part 1, General Equations and Uncertainty Guidelines, Third Edition, September 1990, reaffirmed August 1995; also available as ANSI/API 2530, Part 1, 1991, API Stock No. H30350.	§ 250.1203(b)(2).
API MPMS, Chapter 14, Section 3, Part 2, Specification and Installation Requirements, Third Edition, February 1991, reaffirmed May 1996, API Stock No. H30351; also available as ANSI/API 2530, 1991.	§ 250.1203(b)(2).
API MPMS, Chapter 14, Section 3, Part 3, Natural Gas Applications, Third Edition, August 1992, reaffirmed December 1998, API Stock No. H30353; also available as ANS/API 2530, Part 3.	§ 250.1203(b)(2).
API MPMS, Chapter 14, Section 5, Calculation of Gross Heating Value, Relative Density, and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, Revised 1996; order from Gas Processors Association, 6526 East 60th Street, Tulsa, Oklahoma 74145..	§ 250.1203(b)(2).
API MPMS, Chapter 14, Section 6, Continuous Density Measurement, Second Edition, April 1991, reaffirmed May 1998, API Stock No. H30346.	§ 250.1203(b)(2).
API MPMS, Chapter 14, Section 8, Liquefied Petroleum Gas Measurement, Second Edition, July 1997; reaffirmed May 1996, API Stock No. H14082.	§ 250.1203(b)(2).
API MPMS, Chapter 20, Section 1, Allocation Measurement, First Edition, September 1993, API Stock No. H30730.	§ 250.1202(k)(1).
API MPMS, Chapter 21, Section 1, Electronic Gas Measurement, First Edition, September 1993, API Stock No. H30730.	§ 250.1203(b)(4).
API RP 2A, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms Working Stress Design, Nineteenth Edition, August 1, 1991, API Stock No. 811–00200.	§ 250.900(g); § 250.912(a).
API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms-Working Stress Design; Twentieth Edition, July 1, 1993, API Stock No. G00200.	§ 250.900(g); § 250.912(a).

Title of documents	Incorporated by reference at
API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms-Working Stress Design; Twentieth Edition, July 1, 1993, Supplement 1, December 1996, Effective Date, February 1, 1997, API Stock No. G00205.	§ 250.900(g); § 250.912(a).
API RP 2D, Recommended practice for Operation and Maintenance of Offshore Cranes, Fourth Edition, August 1, 1999. API Stock No. G02D04.	§ 250.108(a)(1).
API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fourth Edition, July 1, 1994, with Errata dated June 1996, API Stock No. G14B04.	§ 250.801(e)(4); § 250.804(a)(1)(i).
API RP 14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Sixth Edition, March 1998, API Stock No. G14C06.	§ 250.802(b), (e)(2); § 250.803(a), (b)(2)(i), (b)(4), (b)(5)(i), (b)(7), (b)(9)(v), (c)(2); § 250.804(a), (a)(5); § 250.1002(d); § 250.1004(b)(9); § 250.1628(c), (d)(2); § 250.1629(b)(2), (b)(4)(v); § 250.1630(a).
API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1, 1991, API Stock No. G07185.	§ 250.802(e)(3); § 250.1628(b)(2), (d)(3).
API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms, Third Edition, September 1, 1991, API Stock No. G07190.	§ 250.114(c); § 250.803(b)(9)(v); § 250.1629(b)(4)(v).
API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, Third Edition, December 1, 1993, API Stock No. G07194.	§ 250.803(b)(8), (b)(9)(v); § 250.1629(b)(3), (b)(4)(v).
API RP 14H, Recommended Practice for the Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fourth Edition, July 1, 1994, API Stock No. G14H04.	§ 250.802(d); 250.804(a)(4).
API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997, API Stock No. C50002.	§ 250.114(a); § 250.410(e); § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3); (d)(4)(i); § 250.1629(b)(4)(i).
API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, First Edition, November 1997, API Stock No. C50501.	§ 250.114(a); § 250.410(e); § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3); (d)(4)(i); § 250.1629(b)(4)(i).
API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993, API Stock No. H25560; also available under the umbrella of the MPMS.	§ 250.1202(l)(4).
API Spec Q1, Specification for Quality Programs for the Petroleum and Natural Gas Industry, Sixth Edition, March 1, 1999. API Stock No. GQ1006.	§ 250.806(a)(2)(ii).
API Spec 6A, Specification for Wellhead and Christmas Tree Equipment, Seventeenth Edition, February 1, 1996, API Stock No. G06A17.	§ 250.806(a)(3); § 250.1002 (b)(1), (b)(2).
API Spec 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996, API Stock No. G06AV1..	§ 250.806(a)(3).
API Spec 6D, Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves), Twenty-first Edition, March 31, 1994, including Supplement 2, December 1, 1997, API Stock No. G03200.	§ 250.1002(b)(1).
API Spec 14A, Specification for Subsurface Safety Valve Equipment, Ninth Edition, July 1, 1994, API Stock No. G14A09.	§ 250.806(a)(3).
API Standard 2551, Standard Method for Measurement and Calibration of Horizontal Tanks, First Edition, 1965, reaffirmed January 1997; API Stock No. H25510; also available under the umbrella of the MPMS.	§ 250.1202(l)(4).
API Standard 2552, Measurement and Calibration of Spheres and Spheroids, First Edition, 1966, reaffirmed January 1997, API Stock No. H25520; also available under the umbrella of the MPMS.	§ 250.1202(l)(4).
API Standard 2555, Method for Liquid Calibration of Tanks, September 1966, reaffirmed January 1997, API Stock No. H25550; also available under the umbrella of the MPMS.	§ 250.1202(l)(4).
ASTM Standard C 33–99a. Standard Specification for Concrete Aggregates	§ 250.908(b)(4)(i).
ASTM Standard C 94/C 94M–99, Standard Specification for Ready-Mixed Concrete	§ 250.908(e)(2)(i).
ASTM Standard C 150–99, Standard Specification for Portland Cement	§ 250.908(b)(2)(i).
ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete.	§ 250.908(b)(4)(i).
ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements	§ 250.908(b)(2)(i).
AWS D1.1–96, Structural Welding Code—Steel, 1996, including Commentary	§ 250.907(b)(1)(i)
AWS D1.4–79, Structural Welding Code—Reinforcing Steel, 1979	§ 250.908(e)(3)(ii)
NACE Standard MR0175–99, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, Revised January 1999, NACE Item No. 21302.	§ 250.417(p)(2).
NACE Standard RP 01–76–94, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production.	§ 250.907(d).

[64 FR 72775, Dec. 28, 1999, as amended at 65 FR 218, 219, Jan. 4, 2000; 65 FR 3127, Jan. 20, 2000; 65 FR 14470, Mar. 17, 2000; 65 FR 15863, Mar. 24, 2000; 65 FR 18432, Apr. 7, 2000; 65 FR 25285, May 1, 2000; 65 FR 36328, June 8, 2000; 65 FR 40052, June 29, 2000]

§ 250.199 Paperwork Reduction Act statements—information collection.

(a) OMB has approved the information collection requirements in part 250 under 44 U.S.C. 3501 *et seq.* The table in paragraph (e) of this section lists the subpart in the rule requiring the information and its title, provides the OMB control number, and summarizes the reasons for collecting the information and how MMS uses the information. The associated MMS forms required by this part are listed at the end of this table with the relevant information.

(b) Respondents are OCS oil, gas, and sulphur lessees and operators. The requirement to respond to the information collections in this part is mandated under the Act (43 U.S.C. 1331 *et seq.*) and the Act's Amendments of 1978 (43 U.S.C. 1801 *et seq.*). Some responses are also required to obtain or retain a benefit or may be voluntary. Proprietary information will be protected under § 250.196, Data and information to be made available to the public; parts 251 and 252; and the Freedom of Information Act (5 U.S.C. 552) and its implementing regulations at 43 CFR part 2.

(c) The Paperwork Reduction Act of 1995 requires us to inform the public that an agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

(d) Send comments regarding any aspect of the collections of information under this part, including suggestions for reducing the burden, to the Information Collection Clearance Officer, Minerals Management Service, Mail Stop 4230, 1849 C Street, NW., Washington, DC 20240.

(e) MMS is collecting this information for the reasons given in the following table:

30 CFR 250 subpart/title (OMB control No.)	Reasons for collecting information and how used
(1) Subpart A, General (1010–0114)	To inform MMS of actions taken to comply with general operational requirements on the OCS. To ensure that operations on the OCS meet statutory and regulatory requirements, are safe and protect the environment, and result in diligent exploration, development, and production on OCS leases. To support the unproved and proved reserve estimation, resource assessment, and fair market value determinations.
(2) Subpart B, Exploration and Development and Production Plans (1010–0049).	To inform MMS, States, and the public of planned exploration, development, and production operations on the OCS. To ensure that operations on the OCS are planned to comply with statutory and regulatory requirements, will be safe and protect the human, marine, and coastal environment, and will result in diligent exploration, development, and production of leases.
(3) Subpart C, Pollution Prevention and Control (1010–0057)	To inform MMS of measures to be taken to prevent water and air pollution. To ensure that appropriate measures are taken to prevent water and air pollution.
(4) Subpart D, Oil and Gas Drilling Operations (1010–0053)	To inform MMS of the equipment and procedures to be used in drilling operations on the OCS. To ensure that drilling operations are safe and protect the human, marine, and coastal environment.
(5) Subpart E, Oil and Gas Well-Completion Operations (1010–0067).	To inform MMS of the equipment and procedures to be used in well-completion operations on the OCS. To ensure that well-completion operations are safe and protect the human, marine, and coastal environment.
(6) Subpart F, Oil and Gas Well-Workover Operations (1010–0043).	To inform MMS of the equipment and procedures to be used during well-workover operations on the OCS. To ensure that well-workover operations are safe and protect the human, marine, and coastal environment.
(7) Subpart G, Abandonment of Wells (1010–0079)	To inform MMS of procedures to be used during the temporary and permanent abandonment of wells. To ensure that wells are abandoned in a manner that is safe and minimizes conflicts with other uses of the OCS.

30 CFR 250 subpart/title (OMB control No.)	Reasons for collecting information and how used
(8) Subpart H, Oil and Gas Production Safety Systems (1010–0059).	To inform MMS of the equipment and procedures to be used during production operations on the OCS. To ensure that production operations are safe and protect the human, marine, and coastal environment.
(9) Subpart I, Platforms and Structures (1010–0058)	To provide MMS with information regarding the design, fabrication, and installation of platforms on the OCS. To ensure the structural integrity of platforms installed on the OCS.
(10) Subpart J, Pipelines and Pipeline Rights-of-Way (1010–0050).	To provide MMS with information regarding the design, installation, and operation of pipelines on the OCS. To ensure that pipeline operations are safe and protect the human, marine, and coastal environment.
(11) Subpart K, Oil and Gas Production Rates (1010–0041)	To inform MMS of production rates for hydrocarbons produced on the OCS. To ensure economic maximization of ultimate hydrocarbon recovery.
(12) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1010–0051).	To inform MMS of the measurement of production, commingling of hydrocarbons, and site security plans. To ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security is maintained.
(13) Subpart M, Unitization (1010–0068)	To inform MMS of the unitization of leases. To ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(14) Subpart N, Remedies and Penalties (1010–0121)	The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4.
(15) Subpart O, Training (1010–0078)	To inform MMS of training program curricula, course schedules, and attendance. To ensure that training programs are technically accurate and sufficient to meet safety and environmental requirements, and that workers are properly trained to operate on the OCS.
(16) Subpart P, Sulphur Operations (1010–0086)	To inform MMS of sulphur exploration and development operations on the OCS. To ensure that OCS sulphur operations are safe; protect the human, marine, and coastal environment; and will result in diligent exploration, development, and production of sulphur leases.
(17) Forms MMS–123, Application for Permit to Drill, and MMS–123S, Supplemental APD Information Sheet, Subparts D, E, P (1010–0044 and 1010–0131).	To inform MMS of the procedures and equipment to be used in drilling operations. To ensure that drilling and well-completion are safe and protect the environment, use adequate equipment, conform with provisions of the lease, and the public is informed.
(18) Form MMS–124, Sundry Notices & Reports on Wells, Subparts D, E, F, G, P (1010–0045).	To inform MMS of well-completion and well-workover operations, changes to any ongoing well operations, and well abandonment operations. To ensure that MMS has up-to-date and accurate information on OCS drilling and other lease operations; operations are safe and protect the human, marine, and coastal environment; abandoned sites are cleared of obstructions; and the public is informed.
(19) Form MMS–125, Well Summary Report, Subparts D, E, F, P (1010–0046).	To inform MMS of the results of well-completion or well-workover operations or changes in well status or condition. To ensure that MMS has up-to-date and accurate information on the status and condition of wells.
(20) Form MMS–126, Well Potential Test Report, Subpart K (1010–0039).	To inform MMS of the production potential of an oil or gas well and to verify a requested production rate. To ensure that production results in ultimate full recovery of hydrocarbons, and energy resources are produced at a prudent rate.
(21) Form MMS–127, Request for Reservoir Maximum Efficiency Rate (MER), Subpart K (1010–0018).	To inform MMS of data concerning oil and gas well-completion in a rate-sensitive reservoir and to verify requested efficiency rate. To ensure that reservoirs are classified correctly and the requested production rate will not waste oil or gas.
(22) Form MMS–128, Semiannual Well Test Report, Subpart K (1010–0017).	To inform MMS of the status and capacity of gas wells and verify production capacity. To ensure that depletion of reservoirs results in greatest ultimate recovery of hydrocarbons.
(23) Form MMS–131, Performance Measures Data (Voluntary) (1010–0112).	To collect data related to a set of performance measures. To evaluate the effectiveness of industry's continued improvement of safety and environmental management in the OCS.
(24) Form MMS–132, Evacuation Statistics (used in the GOM Region), Subpart A (1010–0114).	To inform MMS in the event of a major disruption in the availability and supply of natural gas and oil due to natural occurrences/hurricanes. To advise the USCG of rescue needs, and to alert the news media and interested public entities when production is shut in and when resumed.
(25) Form MMS–133, Weekly Activity Report (used in the GOM Region), Subpart D (1010–0132).	To inform MMS of well status, well and casing tests, and well casing configuration data. To have accurate data and information on the wells under MMS jurisdiction to ensure compliance with approved plans.

Subpart B—Exploration and Development and Production Plans

§ 250.200 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 § 250.204(d)).

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.201 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.

§ 250.202 Well location and spacing.

(a) The Regional Supervisor is authorized to approve well location and spacing programs necessary for exploration and development of a leased sulphur deposit or fluid hydrocarbon reservoir giving consideration to, among other factors, the location of drilling units and platforms, extent and thickness of the sulphur deposit, geological and other reservoir characteristics, number of wells that can be economically drilled, protection of correlative rights, optimum recovery of resources, minimization of risk to the environment, and prevention of any unreasonable interference with other uses of the OCS. Well location and spacing programs shall be determined independently for each leased sulphur deposit or hydrocarbon-bearing reservoir in a manner that will locate wells in the optimum position for the most effective production of sulphur and/or 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.

(c) The lessee shall drill and produce the wells the Regional Supervisor determines are necessary to protect the lessor from loss by reason of production on other properties or in lieu thereof, with the approval of the Regional Supervisor, pay a sum determined by the Regional Supervisor as adequate to compensate the lessor for the lessee's failure to drill and produce any well. Payment of that sum shall be considered as the equivalent of production in paying quantities for the purpose of extending the lease term.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990; 56 FR 32099, July 15, 1991. Redesignated at 63 FR 29749, May 29, 1998]

§ 250.203 Exploration Plan.

(a) The leasee 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 response plan as described in part 254 or reference to an approved Regional Response 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 § 250.417 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 § 250.417 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) If the Regional Director believes that an archaeological resource may exist in the lease area, the Regional Director will notify the lessee in writing. Prior to commencing any operations, the lessee shall prepare a report, as specified by the Regional Director, to determine the potential existence of any archaeological resource that may be affected by operations. The report shall be prepared by an archaeologist and geophysicist and shall be based on an assessment of data from remote-sensing surveys and of other pertinent archaeological and environmental information.

(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 § 250.303 or § 250.304 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)(19)(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 § 250.303 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 we deem the Exploration Plan submitted, the Regional Supervisor will send by receipted mail a copy of the plan (except those portions exempt from disclosure under the Freedom of Information Act and 43 CFR part 2) to the Governor or the Governor's designated representative and the CZM agency of each affected State. Consistency review begins when the State's CZM agency receives a copy of the deemed submitted plan, consistency certification, and required necessary data and information as directed by 15 CFR 930.78.

(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 § 250.182 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 protection of the environment and archaeological resources, the Regional Director may authorize or direct the lessee to conduct geological, geophysical, biological, archaeological, or other surveys or monitoring programs. The lessee shall provide the Regional Director, 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 § 250.414 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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 59 FR 53093, Oct. 21, 1994; 62 FR 13996, Mar. 25, 1997. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 53200, Oct. 1, 1999; 64 FR 72794, Dec. 28, 1999]

§ 250.204 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 § 250.909 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 § 250.417 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 § 250.417 of this part.

(3) A description of the environmental safeguards to be implemented, including an updated oil-spill response plan as described in part 254 of this chapter 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)(i) 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;

(ii) A description of technology and recovery practices and procedures intended to assure optimum recovery of sulphur; or

(iii) A description of technology and recovery practices and procedures intended to assure optimum recovery of oil and gas and sulphur.

(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, gas, and sulphur to shore; the routes to be followed by each mode of transportation; and the estimated quantities of oil, gas, and sulphur 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) If the Regional Director believes that an archaeological resource may exist in the lease area, the Regional Director will notify the lessee in writing. Prior to commencing any operations, the lessee shall prepare a report, as specified by the Regional Director, to determine the potential existence of any archaeological resource that may be affected by operations. The report shall be prepared by an archaeologist and geophysicist and shall be based on an assessment of data from remote-sensing surveys and of other pertinent archaeological and environmental information.

(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) For sulphur operations, the degree of subsidence that is expected at various stages of production, and measures that will be taken to assure safety of operations and protection of the environment. Special attention shall be given to the effects of subsidence on existing or potential oil and gas production, fixed bottom-founded structures, and pipelines.

(10) For sulphur operations, a discussion of the potential toxic or thermal effects on the environment caused by the discharge of bleedwater, including a description of the measures that will be taken into account to mitigate these impacts.

(11) 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).

(12) A discussion of alternatives to the activities proposed that were considered during the development of the plan including a comparison of the environmental effects.

(13) Certificate(s) of coastal zone consistency as provided in 15 CFR part 930.

(14) For each OCS facility, such information described below needed to make the findings under § 250.303 or § 250.304 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)(12)(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 § 250.303 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.

(15) A brief discussion of any approved or anticipated suspensions of production necessary to hold the lease(s) in an active status.

(16) 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.

(17) 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) We will process the plan according to this section and 15 CFR part 930. Accordingly, consistency review begins when the State's CZM agency receives a copy of the deemed submitted plan, consistency certification, and required necessary data and information as directed by 15 CFR 930.78.

(j) The Regional Supervisor will evaluate the environmental impact of the activities described in the Development and Production Plan (DPP) and prepare the appropriate environmental documentation required by the National Environmental Policy Act of 1969. At least once in each planning area (other than the western and central Gulf of Mexico planning areas), we will prepare an environmental impact statement (EIS) and send copies of the draft EIS to the Governor of each affected State and the executive of each affected local government that requests a copy. Additionally, when we prepare a DPP EIS and when the State's federally approved coastal management program requires a DPP NEPA document for use in determining consistency, we will forward a copy of the draft EIS to the State's CZM Agency. We will 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 §§ 250.183 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 §§ 250.183 and 256.77 of this chapter.

(s) To ensure safety and protection of the environment and archaeological resources, the Regional Director may authorize or direct the lessee to conduct geological, geophysical, biological, archaeological, or other surveys or monitoring programs. The lessee shall provide the Regional Director, upon request, copies of any data obtained as a result of those surveys and monitoring programs.

(t) The lessee may not drill any well until the District Supervisor's approval of an APD, filed in accordance with the requirements of § 250.414 of this part, has been received. All APD's 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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 55 FR 47752, Nov. 15, 1990; 56 FR 32099, July 15, 1991; 59 FR 53093, Oct. 21, 1994; 62 FR 13996, Mar. 25, 1997. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 9065, Feb. 24, 1999; 64 FR 53200, Oct. 1, 1999; 64 FR 72794, Dec. 28, 1999]

Subpart C—Pollution Prevention and Control

§ 250.300 Pollution prevention.

(a) During the exploration, development, production, and transportation of oil and gas or sulphur, the lessee shall take measures to prevent unauthorized discharge of pollutants into the offshore waters. The lessee shall not create conditions that will pose unreasonable risk to 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.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 32099, July 15, 1991. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.301 Inspection of facilities.

(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.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 13996, Mar. 25, 1997. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.302 Definitions concerning air quality.

For purposes of §§ 250.303 and 250.304 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 for oil, gas, or sulphur 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, gas, or sulphur 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.

[53 FR 10690, Apr. 1, 1988, as amended at 56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.303 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 § 250.303 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 § 250.203(b)(19) or § 250.204(b)(12) 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 § 250.203(b)(19)(i)(A) or § 250.204(b)(12)(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 (µG/M³)

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 (μG/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—arithmetric.

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.

[53 FR 10690, Apr. 1, 1988; 53 FR 19856, May 31, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.304 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 § 250.203(b)(19) or 250.204(b)(12) 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 § 250.203(b)(19)(i)(A) or 250.204(b)(12)(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 (µG/M³)

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 § 250.174 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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

Subpart D—Oil and Gas Drilling Operations

§ 250.400 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.

§ 250.401 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–123, Application for Permit to Drill (APD), in accordance with § 250.414. 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 § 250.903 of this part shall be used for any required third-party review.

(b) *Drilling unit safety devices.* (1) No later than May 31, 1989, 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 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.

(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 §§ 250.203 and 250.204 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) *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.

(h) *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.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 55 FR 47752, Nov. 15, 1990; 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§§ 250.402–250.403 [Reserved]

§ 250.404 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.

§ 250.405 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.

§ 250.406 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 § 250.414(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 must be essentially full-opening and tested according to the test pressure and test frequency as stated in § 250.407 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 63 FR 29607, June 1, 1998]

§ 250.407 Blowout preventer (BOP) system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Supervisor may require testing every 7 days if conditions or BOP performance warrant; and

(3) Before drilling out each string of casing or a liner. The District Supervisor may allow you to omit this test if you did not remove the BOP stack to run the casing string or liner and the required BOP-test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your

APD which casing strings and liners meet these criteria.

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

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment or the pressure otherwise approved by the District Supervisor; and

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment or the pressure otherwise approved by the District Supervisor.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) *Additional BOP testing requirements.* You must:

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

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further drilling operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram during a stump test and at all casing points. Additionally, the interval between any blind or blind-shear ram tests may not exceed 30 days;

(5) Function test annulars and rams every 7 days between pressure tests;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools;

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

(8) Actuate safety valves assembled with proper casing connections prior to running casing, and

(9) If you install casing rams, you must test the ram bonnet before running casing.

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems such as lost circulation, formation fluid influx, or stuck drill pipe. If this occurs, you must conduct the required BOP test on the first trip out of the hole. You must record the reason for postponing any test in the driller's report.

(f) *Visual inspections.* You must visually inspect your surface and subsea BOP systems and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect subsea equipment. The District Supervisor may approve alternate methods and frequencies to inspect a marine riser. Casing risers on fixed structures and jackup rigs are not subject to the daily underwater inspections.

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

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

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

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

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

(7) After drilling is completed, you must retain all the records listed in paragraph (h)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the Outer Continental Shelf (OCS) facility, or at another location conveniently available to the District Supervisor.

(i) *Alternate methods.* The District Supervisor may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

[63 FR 29607, June 1, 1998]

§ 250.408 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.

§ 250.409 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.

§ 250.410 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 mud-handling areas*. Mud-handling areas which are classified as per API RP 500 or API RP 505 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.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990. Redesignated at 63 FR 29479, May 29, 1998, as amended at 65 FR 40052, June 29, 2000]

§ 250.411 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.

§ 250.412 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.

§ 250.413 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 must be trained and qualified according to Subpart O of this part. 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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.414 Applications for permit to drill.

(a) Prior to commencing the 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–123, 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 has been given pursuant to § 250.140.

(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–123:

(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 § 250.190 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.415 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–124, 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–124 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–124. 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–124 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 § 250.190 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.416 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 § 250.170 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–125, Well Summary Report, or Form MMS–124, 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–124, 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.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.417 Hydrogen sulfide.

(a) *What precautions must I take when operating in an H_2S area?* You must:

(1) Take all necessary and feasible precautions and measures to protect personnel from the toxic effects of H_2S and to mitigate damage to property and the environment caused by H_2S. You must follow the requirements of this section when conducting drilling, well-completion/well-workover, and production operations in zones with H_2S present and when conducting operations in zones where the presence of H_2S is unknown. You do not need to follow these requirements when operating in zones where the absence of H_2S has been confirmed; and

(2) Follow your approved contingency plan.

(b) *Definitions.* Terms used in this section have the following meanings:

Facility means a vessel, a structure, or an artificial island used for drilling, well-completion, well-workover, and/or production operations.

H_2S absent means:

(1) Drilling, logging, coring, testing, or producing operations have confirmed the absence of H_2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S; or

(2) Drilling in the surrounding areas and correlation of geological and seismic data with equivalent stratigraphic units have confirmed an absence of H_2S throughout the area to be drilled.

H_2S present means that drilling, logging, coring, testing, or producing operations have confirmed the presence of H_2S in concentrations and volumes that could potentially result in atmospheric concentrations of 20 ppm or more of H_2S.

H_2S unknown means the designation of a zone or geologic formation where neither the presence nor absence of H_2S has been confirmed.

Well-control fluid means drilling mud and completion or workover fluid as appropriate to the particular operation being conducted.

(c) *Classifying an area for the presence of H_2S.* You must:

(1) Request and obtain an approved classification for the area from the Regional Supervisor before you begin operations. Classifications are ''H_2S absent,'' H_2S present,'' or ''H_2S unknown'';

(2) Submit your request with your application for permit to drill;

(3) Support your request with available information such as geologic and geophysical data and correlations, well logs, formation tests, cores and analysis of formation fluids; and

(4) Submit a request for reclassification of a zone when additional data indicate a different classification is needed.

(d) *What do I do if conditions change?* If you encounter H_2S that could potentially result in atmospheric concentrations of 20 ppm or more in areas not previously classified as having H_2S present, you must immediately notify MMS and begin to follow requirements for areas with H_2S present.

(e) *What are the requirements for conducting simultaneous operations?* When conducting any combination of drilling, well-completion, well-workover, and production operations simultaneously, you must follow the requirements in the section applicable to each individual operation.

(f) *Requirements for submitting an H_2S Contingency Plan.* Before you begin operations, you must submit an H_2S Contingency Plan to the District Supervisor for approval. Do not begin operations before the District Supervisor approves your plan. You must keep a copy of the approved plan in the field, and you must follow the plan at all times. Your plan must include:

(1) Safety procedures and rules that you will follow concerning equipment, drills, and smoking;

(2) Training you provide for employees, contractors, and visitors;

(3) Job position and title of the person responsible for the overall safety of personnel;

(4) Other key positions, how these positions fit into your organization, and what the functions, duties, and responsibilities of those job positions are;

(5) Actions that you will take when the concentration of H_2S in the atmosphere reaches 20 ppm, who will be responsible for those actions, and a description of the audible and visual alarms to be activated;

(6) Briefing areas where personnel will assemble during an H_2S alert. You must have at least two briefing areas on each facility and use the briefing area that is upwind of the H_2S source at any given time;

(7) Criteria you will use to decide when to evacuate the facility and procedures you will use to safely evacuate all personnel from the facility by vessel, capsule, or lifeboat. If you use helicopters during H_2S alerts, describe the types of H_2S emergencies during which you consider the risk of helicopter activity to be acceptable and the precautions you will take during the flights;

(8) Procedures you will use to safely position all vessels attendant to the facility. Indicate where you will locate the vessels with respect to wind direction. Include the distance from the facility and what procedures you will use to safely relocate the vessels in an emergency;

(9) How you will provide protective-breathing equipment for all personnel, including contractors and visitors;

(10) The agencies and facilities you will notify in case of a release of H_2S (that constitutes an emergency), how you will notify them, and their telephone numbers. Include all facilities that might be exposed to atmospheric concentrations of 20 ppm or more of H_2S;

(11) The medical personnel and facilities you will use if needed, their addresses, and telephone numbers;

(12) H_2S detector locations in production facilities producing gas containing 20 ppm or more of H_2S. Include an ''H_2S Detector Location Drawing'' showing:

(i) All vessels, flare outlets, wellheads, and other equipment handling production containing H_2S;

(ii) Approximate maximum concentration of H_2S in the gas stream; and

(iii) Location of all H_2S sensors included in your contingency plan;

(13) Operational conditions when you expect to flare gas containing H_2S including the estimated maximum gas flow rate, H_2S concentration, and duration of flaring;

(14) Your assessment of the risks to personnel during flaring and what precautionary measures you will take;

(15) Primary and alternate methods to ignite the flare and procedures for sustaining ignition and monitoring the status of the flare (i.e., ignited or extinguished);

(16) Procedures to shut off the gas to the flare in the event the flare is extinguished;

(17) Portable or fixed sulphur dioxide (SO_2)-detection system(s) you will use to determine SO_2 concentration and exposure hazard when H_2S is burned;

(18) Increased monitoring and warning procedures you will take when the SO_2 concentration in the atmosphere reaches 2 ppm;

(19) Personnel protection measures or evacuation procedures you will initiate when the SO_2 concentration in the atmosphere reaches 5 ppm;

(20) Engineering controls to protect personnel from SO_2; and

(21) Any special equipment, procedures, or precautions you will use if you conduct any combination of drilling, well-completion, well-workover, and production operations simultaneously.

(g) *Training program.*

(1) *When and how often do employees need to be trained?* All operators and contract personnel must complete an H_2S training program to meet the requirements of this section:

(i) Before beginning work at the facility; and

(ii) Each year, within 1 year after completion of the previous class.

(2) *What training documentation do I need?* For each individual working on the platform, either:

(i) You must have documentation of this training at the facility where the individual is employed; or

(ii) The employee must carry a training completion card.

(3) *What training do I need to give to visitors and employees previously trained on another facility?*

(i) Trained employees or contractors transferred from another facility must attend a supplemental briefing on your H_2S equipment and procedures before beginning duty at your facility;

(ii) Visitors who will remain on your facility more than 24 hours must receive the training required for employees by paragraph (g)(4) of this section; and

(iii) Visitors who will depart before spending 24 hours on the facility are exempt from the training required for employees, but they must, upon arrival, complete a briefing that includes:

(A) Information on the location and use of an assigned respirator; practice in donning and adjusting the assigned respirator; information on the safe briefing areas, alarm system, and hazards of H_2S and SO_2; and

(B) Instructions on their responsibilities in the event of an H_2S release.

(4) *What training must I provide to all other employees?* You must train all individuals on your facility on the:

(i) Hazards of H_2S and of SO_2 and the provisions for personnel safety contained in the H_2S Contingency Plan;

(ii) Proper use of safety equipment which the employee may be required to use;

(iii) Location of protective breathing equipment, H_2S detectors and alarms, ventilation equipment, briefing areas, warning systems, evacuation procedures, and the direction of prevailing winds;

(iv) Restrictions and corrective measures concerning beards, spectacles, and contact lenses in conformance with ANSI Z88.2;

(v) Basic first-aid procedures applicable to victims of H_2S exposure. During all drills and training sessions, you must address procedures for rescue and first aid for H_2S victims;

(vi) Location of:

(A) The first-aid kit on the facility;

(B) Resuscitators; and

(C) Litter or other device on the facility.

(vii) Meaning of all warning signals.

(5) *Do I need to post safety information?* You must prominently post safety information on the facility and on vessels serving the facility (i.e,, basic first-aid, escape routes, instructions for use of life boats, etc.).

(h) *Drills. (1) When and how often do I need to conduct drills on H_2S* safety discussions on the facility? You must:

(i) Conduct a drill for each person at the facility during normal duty hours at least once every 7-day period. The drills must consist of a dry-run performance of personnel activities related to assigned jobs.

(ii) At a safety meeting or other meetings of all personnel, discuss drill performance, new H_2S considerations at the facility, and other updated H_2S information at least monthly.

(2) *What documentation do I need?* You must keep records of attendance for:

(i) Drilling, well-completion, and well-workover operations at the facility until operations are completed; and

(ii) Production operations at the facility or at the nearest field office for 1 year.

(i) *Visual and audible warning systems*—(1) *How must I install wind direction equipment?* You must install wind-direction equipment in a location visible at all times to individuals on or in the immediate vicinity of the facility.

(2) *When do I need to display operational danger signs, display flags, or activate visual or audible alarms?*

(i) You must display warning signs at all times on facilities with wells capable of producing H_2S and on facilities that process gas containing H_2S in concentrations of 20 ppm or more.

(ii) In addition to the signs, you must activate audible alarms and display flags or activate flashing red lights when atmospheric concentration of H_2S reaches 20 ppm.

(3) *What are the requirements for signs?* Each sign must be a high-visibility yellow color with black lettering as follows:

Letter height	Wording
12 inches	Danger. Poisonous Gas. Hydrogen Sulfide.
7 inches	Do not approach if red flag is flying.
(Use appropriate wording at right).	Do not approach if red lights are flashing.

(4) *May I use existing signs?* You may use existing signs containing the words ''Danger-Hydrogen Sulfide-H_2S,'' provided the words ''Poisonous Gas. Do Not Approach if Red Flag is Flying'' or ''Red Lights are Flashing'' in lettering of a minimum of 7 inches in height are displayed on a sign immediately adjacent to the existing sign.

(5) *What are the requirements for flashing lights or flags?* You must activate a sufficient number of lights or hoist a sufficient number of flags to be visible to vessels and aircraft. Each light must be of sufficient intensity to be seen by approaching vessels or aircraft any time it is activated (day or night). Each flag must be red, rectangular, a minimum width of 3 feet, and a minimum height of 2 feet.

(6) *What is an audible warning system*? An audible warning system is a public address system or siren, horn, or other similar warning device with a unique sound used only for H_2S.

(7) *Are there any other requirements for visual or audible warning devices?* Yes, you must:

(i) Illuminate all signs and flags at night and under conditions of poor visibility; and

(ii) Use warning devices that are suitable for the electrical classification of the area.

(8) *What actions must I take when the alarms are activated*? When the warning devices are activated, the designated responsible persons must inform personnel of the level of danger and issue

instructions on the initiation of appropriate protective measures.

(j) *H_2S-detection and H_2S monitoring equipment*—(1) *What are the requirements for an H_2S detection system?* An H_2S detection system must:

(i) Be capable of sensing a minimum of 10 ppm of H_2S in the atmosphere; and

(ii) Activate audible and visual alarms when the concentration of H_2S in the atmosphere reaches 20 ppm.

(2) *Where must I have sensors for drilling, well-completion, and well-workover operations?* You must locate sensors at the:

(i) Bell nipple;

(ii) Mud-return line receiver tank (possum belly);

(iii) Pipe-trip tank;

(iv) Shale shaker;

(v) Well-control fluid pit area;

(vi) Driller's station;

(vii) Living quarters; and

(viii) All other areas where H_2S may accumulate.

(3) *Do I need mud sensors?* The District Supervisor may require mud sensors in the possum belly in cases where the ambient air sensors in the mud-return system do not consistently detect the presence of H_2S.

(4) *How often must I observe the sensors?* During drilling, well-completion and well-workover operations, you must continuously observe the H_2S levels indicated by the monitors in the work areas during the following operations:

(i) When you pull a wet string of drill pipe or workover string;

(ii) When circulating bottoms-up after a drilling break;

(iii) During cementing operations;

(iv) During logging operations; and

(v) When circulating to condition mud or other well-control fluid.

(5) *Where must I have sensors for production operations?* On a platform where gas containing H_2S of 20 ppm or greater is produced, processed, or otherwise handled:

(i) You must have a sensor in rooms, buildings, deck areas, or low-laying deck areas not otherwise covered by paragraph (j)(2) of this section, where atmospheric concentrations of H_2S could reach 20 ppm or more. You must have at least one sensor per 400 square feet of deck area or fractional part of 400 square feet;

(ii) You must have a sensor in buildings where personnel have their living quarters;

(iii) You must have a sensor within 10 feet of each vessel, compressor, wellhead, manifold, or pump, which could release enough H_2S to result in atmospheric concentrations of 20 ppm at a distance of 10 feet from the component;

(iv) You may use one sensor to detect H_2S around multiple pieces of equipment, provided the sensor is located no more than 10 feet from each piece, except that you need to use at least two sensors to monitor compressors exceeding 50 horsepower;

(v) You do not need to have sensors near wells that are shut in at the master valve and sealed closed;

(vi) When you determine where to place sensors, you must consider:

(A) The location of system fittings, flanges, valves, and other devices subject to leaks to the atmosphere; and

(B) Design factors, such as the type of decking and the location of fire walls; and

(vii) The District Supervisor may require additional sensors or other monitoring capabilities, if warranted by site specific conditions.

(6) *How must I functionally test the H_2S Detectors?*

(i) Personnel trained to calibrate the particular H_2S detector equipment being used must test detectors by exposing them to a known concentration in the range of 10 to 30 ppm of H_2S.

(ii) If the results of any functional test are not within 2 ppm or 10 percent, whichever is greater, of the applied concentration, recalibrate the instrument.

(7) *How often must I test my detectors?*

(i) When conducting drilling, drill stem testing, well-completion, or well-workover operations in areas classified as H_2S present or H_2S unknown, test all detectors at least once every 24 hours. When drilling, begin functional testing before the bit is 1,500 feet (vertically) above the potential H_2S zone.

(ii) When conducting production operations, test all detectors at least every 14 days between tests.

(iii) If equipment requires calibration as a result of two consecutive functional tests, the District Supervisor may require that H_2S-detection and H_2S-monitoring equipment be functionally tested and calibrated more frequently.

(8) *What documentation must I keep?*

(i) You must maintain records of testing and calibrations (in the drilling or production operations report, as applicable) at the facility to show the present status and history of each device, including dates and details concerning:

(A) Installation;

(B) Removal;

(C) Inspection;

(D) Repairs;

(E) Adjustments; and

(F) Reinstallation.

(ii) Records must be available for inspection by MMS personnel.

(9) *What are the requirements for nearby vessels?* If vessels are stationed overnight alongside facilities in areas of H_2S present or H_2S unknown, you must equip vessels with an H_2S-detection system that activates audible and visual alarms when the concentration of H_2S in the atmosphere reaches 20 ppm. This requirement does not apply to vessels positioned upwind and at a safe distance from the facility in accordance with the positioning procedure described in the approved H_2S Contingency Plan.

(10) *What are the requirements for nearby facilities?* The District Supervisor may require you to equip nearby facilities with portable or fixed H_2S detector(s) and to test and calibrate those detectors. To invoke this requirement, the District Supervisor will consider dispersion modeling results from a possible release to determine if 20 ppm H_2S concentration levels could be exceeded at nearby facilities.

(11) *What must I do to protect against SO_2 if I burn gas containing H_2S?* You must:

(i) Monitor the SO_2 concentration in the air with portable or strategically placed fixed devices capable of detecting a minimum of 2 ppm of SO_2;

(ii) Take readings at least hourly and at any time personnel detect SO_2 odor or nasal irritation;

(iii) Implement the personnel protective measures specified in the H_2S Contingency Plan if the SO_2 concentration in the work area reaches 2 ppm; and

(iv) Calibrate devices every 3 months if you use fixed or portable electronic sensing devices to detect SO_2.

(12) *May I use alternative measures?* You may follow alternative measures instead of those in paragraph (j)(11) of this section if you propose and the Regional Supervisor approves the alternative measures.

(13) *What are the requirements for protective-breathing equipment?* In an area classified as H_2S present or H_2S unknown, you must:

(i) Provide all personnel, including contractors and visitors on a facility, with immediate access to self-contained pressure-demand-type respirators with hoseline capability and breathing time of at least 15 minutes.

(ii) Design, select, use, and maintain respirators to conform to ANSI Z88.2, American National Standard for Respiratory Protection.

(iii) Make available at least two voice-transmission devices, which can be used while wearing a respirator, for use by designated personnel.

(iv) Make spectacle kits available as needed.

(v) Store protective-breathing equipment in a location that is quickly and easily accessible to all personnel.

(vi) Label all breathing-air bottles as containing breathing-quality air for human use.

(vii) Ensure that vessels attendant to facilities 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.

(viii) During H_2S alerts, limit helicopter flights to and from facilities to the conditions specified in the H_2S Contingency Plan. During authorized flights, the flight crew and passengers must use pressure-demand-type respirators. You must train all members of flight crews in the use of the particular type(s) of respirator equipment made available.

(ix) As appropriate to the particular operation(s), (production, drilling, well-completion or well-workover operations, or any combination of them), provide a system of breathing-air manifolds, hoses, and masks at the facility and the briefing areas. You must provide a cascade air-bottle system for the breathing-air manifolds 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.

(k) *Personnel safety equipment*—(1) *What additional personnel-safety equipment do I need?* You must ensure that your facility has:

(i) Portable H_2S detectors capable of detecting a 10 ppm concentration of H_2S in the air available for use by all personnel;

(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) At least three resuscitators on manned facilities, and a number equal to the personnel on board, not to exceed three, on normally unmanned facilities, complete with face masks, oxygen bottles, and spare oxygen bottles.

(2) *What are the requirements for ventilation equipment?* You must:

(i) Use only explosion-proof ventilation devices;

(ii) Install ventilation devices in areas where H_2S or SO_2 may accumulate; and

(iii) Provide movable ventilation devices in work areas. The movable ventilation devices must be multidirectional and capable of dispersing H_2S or SO_2 vapors away from working personnel.

(3) *What other personnel safety equipment do I need?* You must have the following equipment readily available on each facility:

(i) A first-aid kit of appropriate size and content for the number of personnel on the facility; and

(ii) At least one litter or an equivalent device.

(l) *Do I need to notify MMS in the event of an H_2S release?* You must notify MMS without delay in the event of a gas release which results in a 15-minute time weighted average atmospheric concentration of H_2S of 20 ppm or more anywhere on the facility.

(m) *Do I need to use special drilling, completion and workover fluids or procedures?* When working in an area classified as H_2S present or H_2S unknown:

(1) You may use either water- or oil-base muds in accordance with § 250.300(b)(1).

(2) If you use water-base well-control fluids, and if ambient air sensors detect H_2S, you must immediately conduct either the Garrett-Gas-Train test or a comparable test for soluble sulfides to confirm the presence of H_2S.

(3) If the concentration detected by air sensors in over 20 ppm, personnel conducting the tests must don protective-breathing equipment conforming to paragraph (j)(13) of this section.

(4) You must maintain on the facility sufficient quantities of additives for the control of H_2S, well-control fluid pH, and corrosion equipment.

(i) *Scavengers.* You must have scavengers for control of H_2S available on the facility. When H_2S is detected, you must add scavengers as needed. You must suspend drilling until the scavenger is circulated throughout the system.

(ii) *Control pH.* You must add additives for the control of pH to water-base well-control fluids in sufficient quantities to maintain pH of at least 10.0.

(iii) *Corrosion inhibitors.* You must add additives to the well-control fluid system as needed for the control of corrosion.

(5) You must degas well-control fluids containing H_2S at the optimum location for the particular facility. You must collect the gases removed and burn them in a closed flare system conforming to paragraph (q)(6) of this section.

(n) *What must I do in the event of a kick*? In the event of a kick, you must use one of the following alternatives to dispose of the well-influx fluids 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 must be through pressurized or atmospheric mud-separator equipment depending on volume, pressure and concentration of H_2S. The equipment must be designed to recover well-control fluids and burn the gases separated from the well-control fluid. The well-control fluid must be treated to neutralize H_2S and restore and maintain the proper quality.

(o) *Well testing in a zone known to contain H_2S*. When testing a well in a zone with H_2S present, you must do all of the following:

(1) Before starting a well test, conduct safety meetings for all personnel who will be on the facility during the test. At the meetings, emphasize the use of protective-breathing equipment, first-aid procedures, and the Contingency Plan. Only competent personnel who are trained and are knowledgeable of the hazardous effects of H_2S must be engaged in these tests.

(2) Perform well testing 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, you must continuously monitor H_2S levels.

(3) Not burn produced gases except through a flare which meets the requirements of paragraph (q)(6) of this section. Before flaring gas containing H_2S, you must activate SO_2 monitoring equipment in accordance with paragraph (j)(11) of this section. If you detect SO_2 in excess of 2 ppm, you must implement the personnel protective measures in your H_2S Contingency Plan, required by paragraph (f)(13)(iv) of this section. You must also follow the requirements of § 250.1105. You must pipe gases from stored test fluids into the flare outlet and burn them.

(4) Use downhole test tools and wellhead equipment suitable for H_2S service.

(5) Use tubulars suitable for H_2S service. You must not use drill pipe for well testing without the prior approval of the District Supervisor. Water cushions must be thoroughly inhibited in order to prevent H_2S attack on metals. You must flush the test string fluid treated for this purpose after completion of the test.

(6) Use surface test units and related equipment that is designed for H_2S service.

(p) *Metallurgical properties of equipment*. When operating in a zone with H_2S present, you must use equipment that is constructed of materials with metallurgical properties that resist or prevent sulfide stress cracking (also known as hydrogen embrittlement, stress corrosion cracking, or H_2S embrittlement), chloride-stress cracking, hydrogen-induced cracking, and other failure modes. You must do all of the following:

(1) Use tubulars and other equipment, casing, tubing, drill pipe, couplings, flanges, and related equipment that is designed for H_2S service.

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H_2S-bearing fluids that conform to NACE Standard MR0175–99.

(3) Use temporary downhole well-security devices such as retrievable packers and bridge plugs that are designed for H_2S service.

(4) When producing in zones bearing H_2S, use equipment constructed of materials capable of resisting or preventing sulfide stress cracking.

(5) Keep the use of welding to a minimum during the installation or modification of a production facility. Welding must be done in a manner that ensures resistance to sulfide stress cracking.

(q) *General requirements when operating in an H_2S zone*—(1) *Coring operations.* When you conduct coring operations in H_2S-bearing zones, all personnel in the working area must wear protective-breathing equipment at least 10 stands in advance of retrieving the core barrel. Cores to be transported must be sealed and marked for the presence of H_2S.

(2) *Logging operations.* You must treat and condition well-control fluid in use for logging operations to minimize the effects of H_2S on the logging equipment.

(3) *Stripping operations.* Personnel must monitor displaced well-control fluid returns and wear protective-breathing equipment in the working area when the atmospheric concentration of H_2S reaches 20 ppm or if the well is under pressure.

(4) *Gas-cut well-control fluid or well kick from H_2S-bearing zone.* If you decide to circulate out a kick, personnel in the working area during bottoms-up and extended-kill operations must wear protective-breathing equipment.

(5) *Drill- and workover-string design and precautions.* Drill- and workover-strings must be designed consistent with the anticipated depth, conditions of the hole, and reservoir environment to be encountered. You must minimize exposure of the drill- or workover-string to high stresses as much as practical and consistent with well conditions. Proper handling techniques must be taken to minimize notching and stress concentrations. Precautions must be taken to minimize stresses caused by doglegs, improper stiffness ratios, improper torque, whip, abrasive wear on tool joints, and joint imbalance.

(6) *Flare system.* The flare outlet must be of a diameter that allows easy non-restricted flow of gas. You must locate flare line outlets on the downside of the facility 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. You must equip the flare outlet with an automatic ignition system including a pilot-light gas source or an equivalent system. You must have alternate methods for igniting the flare. You must pipe to the flare system used for H_2S all vents from production process equipment, tanks, relief valves, burst plates, and similar devices.

(7) *Corrosion mitigation.* You must use effective means of monitoring and controlling corrosion caused by acid gases (H_2S and CO_2) in both the downhole and surface portions of a production system. You must take specific corrosion monitoring and mitigating measures in areas of unusually severe corrosion where accumulation of water and/or higher concentration of H_2S exists.

(8) *Wireline lubricators.* Lubricators which may be exposed to fluids containing H_2S must be of H_2S-resistant materials.

(9) *Fuel and/or instrument gas.* You must not use gas containing H_2S for instrument gas. You must not use gas containing H_2S for fuel gas without the prior approval of the District Supervisor.

(10) *Sensing lines and devices.* Metals used for sensing line and safety-control devices which are necessarily exposed to H_2S-bearing fluids must be constructed of H_2S-corrosion resistant materials or coated so as to resist H_2S corrosion.

(11) *Elastomer seals.* You must use H_2S-resistant materials for all seals which may be exposed to fluids containing H_2S.

(12) *Water disposal.* If you dispose of produced water by means other than subsurface injection, you must submit to the District Supervisor an analysis of the anticipated H_2S content of the water at the final treatment vessel and at the discharge point. The District Supervisor may require that the water be treated for removal of H_2S. The District Supervisor may require the submittal of an updated analysis if the water disposal rate or the potential H_2S content increases.

(13) *Deck drains.* You must equip open deck drains with traps or similar devices to prevent the escape of H_2S gas into the atmosphere.

(14) *Sealed voids.* You must take precautions 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.

[62 FR 3795, Jan. 27, 1997. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 65 FR 15864, Mar. 24, 2000]

Subpart E—Oil and Gas Well-Completion Operations

§ 250.500 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.

§ 250.501 Definition.

When used in this subpart, the following term shall have the meaning given below:

Well-completion operations means the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

§ 250.502 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 back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47752, Nov. 15, 1990. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.503 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.

§ 250.504 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 § 250.417 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 § 250.417 of this part as well as the appropriate requirements of this subpart.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.505 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Supervisor in accordance with § 250.513 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.506 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.

§§ 250.507–250.508 [Reserved]

§ 250.509 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 safely support the equipment and proposed operations, taking into consideration the corrosion protection, age of platform, and previous stresses to the platform.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.510 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.

§ 250.511 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.

§ 250.512 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.

§ 250.513 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–123 (see § 250.414 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–124, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–124 (or with Form MMS–123):

(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 § 250.417 of this part.

(c) Within 30 days after completion, Form MMS–125, Well Summary Report, including a schematic of the tubing and subsurface equipment, shall be submitted to the District Supervisor.

(d) Public information copies of Form MMS–125 shall be submitted in accordance with §250.190.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§250.514 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.

§250.515 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–124 or Form MMS–123, 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 if rig air is lost.

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

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

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

(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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993. Redesignated at 62 29479, May 29, 1998]

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

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed; and

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Supervisor may require testing every 7 days if conditions or BOP performance warrant.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. The District Supervisor may approve or require other test pressures or practices. Required test pressures are as follows:

(1) All low pressure tests must be between 200 and 300 psi. Any initial pressure above 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test. You must conduct the low pressure test before the high pressure test.

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment.

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) *Additional BOP testing requirements.* You must:

(1) Use water to test the surface BOP system;

(2) Stump test a subsurface BOP system before installation. You must use water to stump test a subsea BOP system. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system;

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further completion operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram at least every 30 days;

(5) Function test annulars and rams every 7 days;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools; and

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

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible (i.e., first trip out of the hole) after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

(f) *Weekly crew drills.* You must conduct a weekly drill to familiarize all personnel engaged in well-completion operations with appropriate safety measures.

(g) *BOP inspections.* You must visually inspect your BOP system and marine riser at least once each day if weather and sea conditions permit. You may use television cameras to inspect this equipment. The District Supervisor may approve alternate methods and frequencies to inspect a marine riser.

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

(i) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, crew drills, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

(1) Record BOP test pressures on pressure charts;

(2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;

(3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;

(4) Identify the control station or pod used during the test;

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

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

(7) After completion of the well, you must retain all the records listed in paragraph (i)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

(j) *Alternate methods.* The District Supervisor may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

[63 FR 29607, June 1, 1998]

§ 250.517 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 have a pressure rating greater than the shut–in tubing pressure and 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 § 250.801 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47753 Nov. 15, 1990. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

Subpart F—Oil and Gas Well-Workover Operations

§ 250.600 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.

§ 250.601 Definitions.

When used in this subpart, the following terms shall have the meanings given below:

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.

Workover operations mean the work conducted on wells after the initial completion for the purpose of maintaining or restoring the productivity of a well.

§ 250.602 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.

§ 250.603 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.

§ 250.604 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 § 250.417 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 § 250.417 of this part as well as the appropriate requirements of this subpart.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.605 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 § 250.613 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.606 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.

§§ 250.607–250.608 [Reserved]

§ 250.609 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.

§ 250.610 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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.611 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.

§ 250.612 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.

§ 250.613 Approval and reporting for well-workover operations.

(a) No well-workover operation except routine ones, as defined in § 250.601 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–124, Sundry Notices and Reports on Wells.

(b) The following information shall be submitted with Form MMS–124:

(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 § 250.417 of this part.

(c) The following additional information shall be submitted with Form MMS–124 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–124, 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–125, Well Summary Report, shall be submitted to the District Supervisor and shall include a new schematic of the tubing subsurface equipment if any subsurface equipment has been changed.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 65 FR 35824, June 6, 2000]

§ 250.614 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.

§250.615 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–124, 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 if rig air is lost;

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

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

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

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line 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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50616, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.616 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 sizes 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 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-workover operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test interval for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

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

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

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

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

(4) Documentation required to be entered in the operation log may instead be referenced in the operations log. All records including pressure charts, operations log, and referenced documents pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of well-workover activity. Following completion of the well-workover actity, all such records shall be retained for a period of 2 years at the facility, at the lessee's filed office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 1915, Jan. 18, 1991. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.617 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 have a pressure rating greater than the shut-in tubing pressure and 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 reinstalled.

(e) Subsurface safety equipment shall be installed, maintained, and tested in compliance with § 250.801 of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 55 FR 47753, Nov. 15, 1990. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.618 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in § 250.601 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

Subpart G—Abandonment of Wells

§ 250.700 General requirements.

(a) 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.

(b) Lessees must plug and abandon all well bores, remove all platforms or other facilities, and clear the ocean of all obstructions to other users. This obligation:

(1) Accrues to the lessee when the well is drilled, the platform or other facility is installed, or the obstruction is created; and

(2) Is the joint and several responsibility of all lessees and owners of operating rights under the lease at the time the obligation accrues, and of each future lessee or owner of operating rights, until the obligation is satisfied under the requirements of this part.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 27955, May 22, 1997. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.701 Approvals.

The lessee shall not commence abandonment operations without prior approval of the District Supervisor. The lessee shall submit a request on Form MMS–124, Sundry Notices and Reports on Wells, 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.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.702 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 § 250.704 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.703 Temporary abandonment.

(a) Any drilling well which is to be temporarily abandoned shall meet the requirements for permanent abandonment (except for the provisions in §§ 250.702 (f) and (i), and 250.704) 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.704 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 on Form MMS–124.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated at 63 FR 29479, May 29, 1998]

Subpart H—Oil and Gas Production Safety Systems

§ 250.800 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.

§ 250.801 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 § 250.806 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 one of 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, or

(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–124, Sundry Notices and Reports on Wells, in § 250.601 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 § 250.804(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 § 250.804 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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

§ 250.802 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 § 250.1004 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 § 250.806 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 for each platform deck outlining all hazardous areas classified according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outlined will 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.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60024, Nov. 26, 1996. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 65 FR 219, Jan. 4, 2000]

§ 250.803 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 § 250.802(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 August 29, 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 change in operating pressures that requires new settings for the high–pressure shut–in sensor and/or the low–pressure shut–in sensor as provided herein. 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, sections A4 and 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 all entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500, or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505.

(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 § 250.403 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 § 250.402 of this part.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988, as amended at 55 FR 47753, Nov. 15, 1990; 61 FR 60025, Nov. 26, 1996. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 65 FR 219, Jan. 4, 2000]

§ 250.804 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.

(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 and 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. 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.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 47753, Nov. 15, 1990; 62 FR 5331, Feb. 5, 1997. Redesignated at 63 FR 29479, May 29, 1998, as amended at 65 FR 35824, June 6, 2000]

§ 250.805 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.

§ 250.806 Safety and pollution prevention equipment quality assurance requirements.

(a) *General requirements.* (1) Except as provided in paragraph (b)(1) of this section, you may install only certified safety and pollution prevention equipment (SPPE) in wells located on the OCS. SPPE includes the following:

(i) Surface safety valves (SSV) and actuators;

(ii) Underwater safety valves (USV) and actuators; and

(iii) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples.

(2) Certified SPPE is equipment the manufacturer certifies as manufactured under a quality assurance program MMS recognizes. MMS considers all other SPPE as noncertified. MMS recognizes two quality assurance programs:

(i) ANSI/ASME SPPE–1, Quality Assurance and Certification of Safety and Pollution-Prevention Equipment Used in Offshore Oil and Gas Operations; and

(ii) API Spec Q1, Specification for Quality Programs.

(3) All SSV's and USV's must meet the technical specifications of API Spec 6A and 6AV1. All SSSV's must meet the technical specifications of API Spec 14A.

(b) *Use of noncertified SPPE.* (1) Before April 1, 1998, you may continue to use and install noncertified SPPE if it was in your inventory as of April 1, 1988, and was included in a list of noncertified SPPE submitted to MMS prior to August 29, 1988.

(2) On or after April 1, 1998:

(i) You may not install additional noncertified SPPE; and

(ii) When noncertified SPPE that is already in service requires offsite repair, remanufacturing, or hot work such as welding, you must replace it with certified SPPE.

(c) *Recognizing other quality assurance programs.* The MMS will consider recognizing other quality assurance programs covering the manufacture of SPPE. If you want MMS to evaluate other quality assurance programs, submit relevant information about the program and reasons for recognition by MMS to the Chief, Engineering and Operations Division; Minerals Management Service; Mail Stop 4700; 381 Elden Street; Herndon, Virginia 20170–4817.

[62 FR 42671, Aug. 8, 1997. Redesignated at 63 FR 29479, May 29, 1998, as amended at 63 FR 37068, July 9, 1998]

§ 250.807 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 § 250.417 of this part, shall be conducted in accordance with that section and other relevant requirements of subpart H, Production Safety Systems.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998]

Subpart I—Platforms and Structures

§ 250.900 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 §§ 250.901 and 250.904 through 250.914 of this subpart. Applications submitted pursuant to § 250.901 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 §§ 250.901 through 250.914 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, May 29, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.901 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 § 250.912 of this part.

(2) A summary of environmental data, as addressed in § 250.904 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 § 250.909 of this part; and

(v) A summary of the seafloor survey results specified in § 250.909(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 §§ 250.905 through 250.909 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 §§ 250.905 through 250.909 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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29485, 29486, May 29, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.902 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 § 250.900(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 § 250.903 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, man-made 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 § 250.901(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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.903 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 §§ 250.904 through 250.911 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 §§ 250.904 through 250.911 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 §§ 250.904 through 250.911 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 §§ 250.904 through 250.911 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 § 250.902(b)(1)(ii) of this part.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.904 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 stillwater 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 riveroutflow 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 § 250.906(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 § 250.905(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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.905 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 § 250.910 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 § 250.904 of this part. Operating environmental loads are loads derived from the parameters characterizing operating environmental conditions (see § 250.904(c)(3) of this part). Design environmental loads are loads derived from the parameters characterizing the design environmental condition (see § 250.904(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 taken into account. Both the drag and lift components of loads due to vortex shedding shall be taken into account.

(v) Where appropriate, flutter and load amplification due to vortex shedding shall be addressed.

(3) Current load information including the following:

(i) Current-induced loads on immersed members of the platform shall be accounted for by defensible methods or the results of model test or site-specific data,

(ii) The lift and drag coefficients used in the determination of current loads shall be appropriate to the current velocity and structural configuration,

(iii) Current velocity profiles used in design shall be appropriate to the installation site,

(iv) For determination of loads induced by the simultaneous occurrence of wave and current fields, the total velocity field 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.

(4) 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.

(5) 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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.906 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 § 250.905 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 §§ 250.907(c)(6) and 250.908(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 § 250.905, 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 250.907, 250.908, and 250.909 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 § 250.904(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 §§ 250.907(d) and 250.908(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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 63 FR 34597, June 25, 1998]

§ 250.907 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 American Institute of Steel Construction (AISC) publication, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, 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 250.905 and 250.906 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 § 250.909(d)(1)(ii) 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 AISC publication, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, 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 § 250.905(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, Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, 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 quailty-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 § 250.906(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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988, as amended at 61 FR 60025, Nov. 26, 1996. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.908 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 must be equivalent to Type I, II, or III portland cement as specified by ASTM Standard C 150–99, Standard Specification for Portland Cement, or portland-pozzolan cement as specified by ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements. However, the suitability of Type III cement to serve its intended function must 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 must conform to the requirements of ASTM Standard C 33–99a, Standard Specification for Concrete Aggregates. Lightweight aggregates conforming to ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete, will only be permitted if they do not pose durability problems and where they are used according to the applicable provisions of the ACI publication, ACI Standard 318, Building Code Requirements for Reinforced Concrete, plus 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; and

(ii) Structural steel used in composite structures shall conform to the requirements of § 250.907 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. 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; 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-dentioning ducts shall conform to the requirements of ACI 318. 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.

(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 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:

$$D+T+L+E_0$$

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 § 250.906(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 § 250.906(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.

(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 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 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. 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 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. 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 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 must conform to the requirements of ACI Standard 318 and ASTM Standard C 94/C 94M–99, Standard 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.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60025, Nov. 26, 1996. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 65 FR 15864, Mar. 24, 2000]

§ 250.909 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.

§ 250.910 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.

§ 250.911 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 § 250.907(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 § 250.907(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 § 250.909(d)(1)(iv) 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 § 250.910(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 § 250.908(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 § 250.910(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.

[53 FR 10690, Apr. 1, 1988; 53 FR 26067, July 11, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.912 Periodic inspection and maintenance.

(a) All platforms installed in the OCS shall be inspected periodically in accordance with the provisions of API RP 2A, section 14, Surveys. However, use of an inspection interval which exceeds 5 years shall require prior 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.

[53 FR 10690, Apr. 1, 1988, as amended at 55 FR 51415, Dec. 14, 1990. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.913 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.

§250.914 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 §250.912 of this part.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

Subpart J—Pipelines and Pipeline Rights-of-Way

§250.1000 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 §250.1001, Definitions) and prior to the installation of a right-of-way pipeline or the modification or relinquishment of a pipeline right-of-way.

(c)(1) Department of the Interior (DOI) pipelines, as defined in §250.1001, must meet the requirements in §§250.1000 through 250.1008.

(2) A pipeline right-of-way grant holder must identify in writing to the Regional Supervisor the operator of any pipeline located on its right-of-way, if the operator is different from the right-of-way grant holder.

(3) A producing operator must identify for its own records, on all existing pipelines located on its lease or right-of-way, the specific points at which operating responsibility transfers to a transporting operator.

(i) Each producing operator must, if practical, durably mark all of its above-water transfer points by April 14, 1999 or the date a pipeline begins service, whichever is later.

(ii) If it is not practical to durably mark a transfer point, and the transfer point is located above water, then the operator must identify the transfer point on a schematic located on the facility.

(iii) If a transfer point is located below water, then the operator must identify the transfer point on a schematic and provide the schematic to MMS upon request.

(iv) If adjoining producing and transporting operators cannot agree on a transfer point by April 14, 1999, the MMS Regional Supervisor and the Department of Transportation (DOT) Office of Pipeline Safety (OPS) Regional Director may jointly determine the transfer point.

(4) The transfer point serves as a regulatory boundary. An operator may write to the MMS Regional Supervisor to request an exception to this requirement for an individual facility or area. The Regional Supervisor, in consultation with the OPS Regional Director and affected parties, may grant the request.

(5) Pipeline segments designed, constructed, maintained, and operated under DOT regulations but transferring to DOI regulation as of October 16, 1998, may continue to operate under DOT design and construction requirements until significant modifications or repairs are made to those segments. After October 16, 1998, MMS operational and maintenance requirements will apply to those segments.

(d) A pipeline which qualifies as a right-of-way pipeline (see §250.1001, 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).

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 63 FR 34597, June 25, 1998; 63 FR 43880, Aug. 17, 1998]

§ 250.1001 Definitions.

Terms used in this subpart shall have the meanings given below:

DOI pipeline refers to a pipeline extending upstream from a point on the OCS where operating responsibility transfers from a producing operator to a transporting operator.

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) Cross any portion of an unleased block(s).

[53 FR 10690, Apr. 1, 1998. Redesignated at 63 FR 29479, May 29, 1998, as amended at 63 FR 43881, Aug. 17, 1998]

§ 250.1002 Design requirements for DOI pipelines.

(a) The internal design pressure for steel pipe shall be determined in accordance with the following formula:

$$P = \frac{2(S)(t)}{D} \times (F)(E)(T)$$

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.

§ 250.1003 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 April 1, 1988, shall be protected from physical damage that could result from contact with floating vessels. Riser protection on pipelines installed on or before April 1, 1988, 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.

(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.

(c) When a pipeline is repaired utilizing a clamp, the clamp shall be a full encirclement clamp able to withstand the anticipated pipeline pressure.

[53 FR 10690, Apr. 1, 1988; 53 FR 12227, Apr. 13, 1988; 57 FR 26997, June 17, 1992. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.1004 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)(i) Incoming pipelines to a platform shall be equipped with a flow safety valve (FSV).

(ii) For sulphur operations, incoming pipelines delivering gas to the power plant platform may be equipped with high- and low-pressure sensors (PSHL), which activate audible and visual alarms in lieu of requirements in paragraph (b)(1)(i) of this section. The PSHL shall be set at 15 percent or 5 psi, whichever is greater, above and below the normal operating pressure range.

(2) Incoming pipelines boarding 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 not to exceed 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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 56 FR 32100, July 15, 1991. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.1005 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.

§ 250.1006 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 paragraph (a) (1) or (2) of this section.

§ 250.1007 What to include in applications.

(a) Applications to install a lease term pipeline or for a pipeline right-of-way grant must be submitted in quadruplicate to the Regional Supervisor. Right-of-way grant applications must include an identification of the operator of the pipeline. Each application must 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. The schematic must indicate the point on the OCS at which operating responsibility transfers between a producing operator and a transporting operator.

(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 required by the Regional Director, an archaeological resource report that covers the entire length of the pipeline. A shallow hazards analysis may be included in a lease term pipeline application in lieu of the shallow hazards survey report with the approval of the Regional Director. The Regional Director 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.

[53 FR 10690, Apr. 1, 1988, as amended at 59 FR 53094, Oct. 21, 1994. Redesignated at 63 FR 29479, May 29, 1998, as amended at 63 FR 43881, Aug. 17, 1998]

§ 250.1008 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 § 250.1005(b) of this part shall be submitted to the Regional Supervisor by the lessee before March of each year.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.1009 General requirements for a pipeline right-of-way grant.

(a)(1) In addition to applicable requirements of §§ 250.1000 through 250.1008 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 pipeline 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) When you apply for, or are the holder of, a right-of-way, you must:

(i) Provide and maintain a $300,000 bond (in addition to the bond coverage required in part 256) that guarantees compliance with all the terms and conditions of the rights-of-way you hold in an OCS area; and

(ii) Provide additional security if the Regional Director determines that a bond in excess of $300,000 is needed.

(2) For the purpose of this paragraph, there are three areas:

(i) The areas offshore the Gulf of Mexico and Atlantic Coast;

(ii) The area offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; and

(iii) The area offshore the Coast of Alaska.

(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 the right-of-way holder discovers any archaeological resource while conducting operations within the right-of-way, the right-of-way holder shall immediately halt operations within the area of the discovery and report the discovery to the Regional Director. If investigations determine that the resource is significant, the Regional Director will inform the lessee how to protect it.

(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, determine to be reasonable, taking into account, among other things, 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 liability 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 § 250.1014 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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1989; 55 FR 47753, Nov. 15, 1990; 59 FR 53094, Oct. 21, 1994; 62 FR 27955, May 22, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 63 FR 34597, June 25, 1998; 64 FR 9065, Feb. 24, 1999]

§ 250.1010 Applications for a pipeline right-of-way grant.

(a) You must submit an original and three copies of an application for a new or modified pipeline right-of-way grant to the Regional Supervisor. The application must address those items required by § 250.1007 (a) or (b) of this subpart, as applicable. It must also state the primary purpose for which you will use the right-of-way grant. If the right-of-way has been used before the application is made, the application must state the date such use began, by whom, and the date the applicant obtained control of the improvement. When you file your application, you must pay the rental required under § 250.1009(c)(2) of this subpart and a non-refundable filing fee of $2,350 for a pipeline right-of-way grant to install a new pipeline or a non-refundable filing fee of $300 for a pipeline right-of-way grant to convert an existing lease term pipeline into a right-of-way pipeline. MMS periodically will amend the filing fee based on its experience with the costs for administering pipeline right-of-way applications. If the costs change by a percentage of not more than the percentage change in the CPI ''U'' since the last change to the filing fee, MMS will amend the application fee by the percentage of the change in costs without notice and opportunity for comment. If costs increase by a percentage more than the percentage change in the CPI ''U'' since the last change to the filing fee, MMS will provide notice and an opportunity to comment before it changes the filing fee. An application to modify an approved right-of-way grant shall be accompanied by the additional rental required under § 250.1009(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.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 39775, July 24, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 64 FR 42598, Aug. 5, 1999]

§ 250.1011 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 § 250.1010(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 (c)(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.

[53 FR 10690, Apr. 1, 1988, as amended at 54 FR 50617, Dec. 8, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.1012 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.

§ 250.1013 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 § 250.1010 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 § 250.1009(b) of this part. No transfer shall be recognized unless and until it is first approved, in writing, by the Regional Supervisor. A nonrefundable filing fee of $60 must accompany the application for the approval of an assignment. MMS periodically will amend the filing fee based on its experience with the costs for administering pipeline right-of-way assignment applications. If the costs increase by more than the CPI ''U,'' MMS will provide notice and opportunity for comment before changing the filing fee. For lesser cost increases or cost reductions MMS will change the fee without such procedures.

[53 FR 10690, Apr. 1, 1988, as amended at 62 FR 39775, July 24, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.1014 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 § 250.1007(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 § 250.1009(c)(9) of this part.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

Subpart K—Oil and Gas Production Rates

§ 250.1100 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.

§ 250.1101 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 § 250.1102(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.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.1102 Oil and gas production rates.

(a) *MER*. (1) The lessee shall submit a proposed MER for each producing sensitive reservoir on Form MMS–127, Request for Reservoir Maximum Efficient Rate (MER), along with appropriate supporting information to the Regional Supervisor within 45 days after discovering that a reservoir is sensitive.

(2) The lessee may propose to revise an MER by submitting Form MMS–127 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–127 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–127 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–127 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–127 for any producing nonsensitive reservoir.

(9) Public information copies of Form MMS–127 shall be submitted in accordance with § 250.190.

(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 within 30 days of the date of first continuous production on all new, recompleted, and reworked well completions. Within 15 days after the end of the test period, the lessee must submit a proposed MPR with well potential test for the individual well completion on Form MMS–126, 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 and shall identify all other wells completed in the reservoir on Form MMS–126.

(3) At least one well test shall be conducted during a calendar half for producing oil-well and gas-well completions and results submitted on Form MMS–128, Semiannual 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 half for a producing oil-well or gas-well completion, the MPR will be automatically canceled effective on the first day of the appropriate following calendar half.

(6) When the results of a semiannual well test for an oil-well or 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.

(8) Public Information copies of Form MMS–126 shall be submitted in accordance with § 250.190.

(9) Public information copies of Form MMS–128 shall be submitted in accordance with § 250.190.

(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.

[53 FR 10690, Apr. 1, 1988, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 64 FR 72794, Dec. 28, 1999; 65 FR 2875, Jan. 19, 2000]

§ 250.1103 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.

§ 250.1104 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.

§ 250.1105 Flaring or venting gas and burning liquid hydrocarbons.

(a) Lessees may flare or vent oil-well gas or gas-well gas without receiving prior approval from the Regional Supervisor only in the following situations:

(1) When gas vapors are flared or vented in small volumes from storage vessels or other low-pressure production vessels and cannot be economically recovered.

(2) During an equipment failure or to relieve system pressures. The lessee must comply with the following conditions:

(i) Lessees must not flare or vent oil-well gas for more than 48 continuous hours unless the Regional Supervisor approves. The Regional Supervisor may specify a limit of less than 48 hours to prevent air quality degradation.

(ii) Lessees must not flare or vent gas from a facility for more than 144 cumulative hours during any calendar month unless the Regional Supervisor approves.

(iii) Lessees must not flare or vent gas-well gas beyond the time required to eliminate an emergency unless the Regional Supervisor approves.

(3) During the unloading or cleaning of a well, drill-stem testing, production testing, or other well-evaluation testing. Flaring or venting must not exceed 48 cumulative hours per testing operation on a single completion. The Regional Supervisor may allow less time to prevent air quality degradation

or more time if lessees need additional time to evaluate reservoir parameters.

(b) Lessees may flare or vent oil-well gas for up to 1 year when the Regional Supervisor approves the request for one of the following reasons:

(1) The lessee initiated an action which, when completed, will eliminate flaring and venting; or

(2) The lessee submitted an evaluation supported by engineering, geologic, and economic data indicating that either:

(i) The oil and gas produced from the well(s) will not economically support the facilities necessary to save and/or sell the gas; or

(ii) There is not enough gas to market.

(c) Lessees may burn produced liquid hydrocarbons only if the Regional Supervisor approves. To burn produced liquid hydrocarbons, the lessee must demonstrate that the amounts to burn would be minimal, or that the alternatives are infeasible or pose a significant risk that may harm offshore personnel or the environment. Alternatives to burning liquid hydrocarbons include transporting the liquids or storing and re-injecting them into a producible zone.

(d) Lessees must prepare records detailing gas flaring or venting and liquid hydrocarbon burning for each facility. The records must include, at a minimum:

(1) Daily volumes of gas flared or vented and liquid hydrocarbons burned;

(2) Number of hours of flaring, venting, or burning on a daily basis;

(3) Reasons for flaring, venting, or burning; and

(4) A list of the wells contributing to flaring, venting, or burning, along with the gas-oil ratio data.

(e) Lessees must keep these records for at least 2 years. Lessees must allow Minerals Management Service representatives to inspect the records at the lessees' field office that is nearest the Outer Continental Shelf facility, or at another location agreed to by the Regional Supervisor. If the Regional Supervisor requests to see the records, lessees must provide a copy.

(f) *Requirements for flaring and venting of gas containing* H_2S—(1) *Flaring of gas* containing H_2S. (i) The Regional Supervisor may, for safety or air pollution prevention purposes, further restrict the flaring of gas containing H_2S. The Regional Supervisor will use information provided in the lessee's H_2S Contingency Plan (§250.417(f)), Exploration Plan or Development and Production Plan, and associated documents in determining the need for such restrictions.

(ii) If the Regional Supervisor determines that flaring at a facility or group of facilities may significantly affect the air quality of an onshore area, the Regional Supervisor may require the operator(s) to conduct an air quality modeling analysis to determine the potential effect of facility emissions on onshore ambient concentrations of SO_2. The Regional Supervisor may require monitoring and reporting or may restrict or prohibit flaring pursuant to §§250.303 and 250.304.

(2) *Venting of gas containing* H_2S. You must not vent gas containing H_2S except for minor releases during maintenance and repair activities that do not result in a 15-minute time weighted average atmospheric concentration of H_2S of 20 ppm or higher anywhere on the platform.

(3) *Reporting flared gas containing* H_2S. In addition to the recordkeeping requirements of paragraphs (d) and (e) of this section, when required by the Regional Supervisor, the operator must submit to the Regional Supervisor a monthly report of flared and vented gas containing H_2S. The report must contain the following information:

(i) On a daily basis, the volume and duration of each flaring episode;

(ii) H_2S concentration in the flared gas; and

(iii) Calculated amount of SO_2 emitted.

[61 FR 25148, May 20, 1996, as amended at 62 FR 3800, Jan. 27, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§250.1106 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.

§ 250.1107 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—Oil and Gas Production Measurement, Surface Commingling, and Security

SOURCE: 63 FR 26370, May 12, 1998, unless otherwise noted. Redesignated at 63 FR 29479, May 29, 1998.

§ 250.1200 Question index table.

The table in this section lists questions concerning Oil and Gas Production Measurement, Surface Commingling, and Security.

Frequently asked questions	CFR citation
1. What are the requirements for measuring liquid hydrocarbons?	§ 250.1202(a)
2. What are the requirements for liquid hydrocarbon royalty meters?	§ 250.1202(b)
3. What are the requirements for run tickets?	§ 250.1202(c)
4. What are the requirements for liquid hydrocarbon royalty meter provings?	§ 250.1202(d)
5. What are the requirements for calibrating a master meter used in royalty meter provings?	§ 250.1202(e)
6. What are the requirements for calibrating mechanical-displacement provers and tank provers?	§ 250.1202(f)
7. What correction factors must a lessee use when proving meters with a mechanical displacement prover, tank prover, or master meter?.	§ 250.1202(g)
8. What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?.	§ 250.1202(h)
9. Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must a lessee do?.	§ 250.1202(i)
10. How must a lessee correct gross liquid hydrocarbon volumes to standard conditions?	§ 250.1202(j)
11. What are the requirements for liquid hydrocarbon allocation meters?	§ 250.1202(k)
12. What are the requirements for royalty and inventory tank facilities?	§ 250.1202(l)
13. To which meters do MMS requirements for gas measurement apply?	§ 250.1203(a)
14. What are the requirements for measuring gas?	§ 250.1203(b)
15. What are the requirements for gas meter calibrations?	§ 250.1203(c)
16. What must a lessee do if a gas meter is out of calibration or malfunctioning?	§ 250.1203(d)
17. What are the requirements when natural gas from a Federal lease is transferred to a gas plant before royalty determination?.	§ 250.1203(e)
18. What are the requirements for measuring gas lost or used on a lease?	§ 250.1203(f)
19. What are the requirements for the surface commingling of production?	§ 250.1204(a)
20. What are the requirements for a periodic well test used for allocation?	§ 250.1204(b)
21. What are the requirements for site security?	§ 250.1205(a)
22. What are the requirements for using seals?	§ 250.1205(b)

[63 FR 26370, May 12, 1998. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1201 Definitions.

Terms not defined in this section have the meanings given in the applicable chapter of the API MPMS, which is incorporated by reference in 30 CFR 250.198. Terms used in Subpart L have the following meaning:

Allocation meter—a meter used to determine the portion of hydrocarbons attributable to one or more platforms, leases, units, or wells, in relation to the total production from a royalty or allocation measurement point.

API MPMS—the American Petroleum Institute's Manual of Petroleum Measurement Standards, chapters 1, 20, and 21.

British Thermal Unit (Btu)—the amount of heat needed to raise the temperature of one pound of water from 59.5 degrees Fahrenheit (59.5 °F) to 60.5 degrees Fahrenheit (60.5 °F) at standard pressure base (14.73 pounds per square inch absolute (psia)).

Calibration—testing (verifying) and correcting, if necessary, a measuring device to industry accepted, manufacturer's recommended, or regulatory required standard of accuracy.

Compositional Analysis—separating mixtures into identifiable components expressed in mole percent.

Gas lost—gas that is neither sold nor used on the lease or unit nor used internally by the producer.

Gas processing plant—an installation that uses any process designed to remove elements or compounds (hydrocarbon and non-hydrocarbon) from gas, including absorption, adsorption, or refrigeration. Processing does not include treatment operations, including those necessary to put gas into marketable conditions such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, desulphurization, and compression. The changing of pressures or temperatures in a reservoir is not processing.

Gas processing plant statement—a monthly statement showing the volume and quality of the inlet or field gas stream and the plant products recovered during the period, volume of plant fuel, flare and shrinkage, and the allocation of these volumes to the sources of the inlet stream.

Gas royalty meter malfunction—an error in any component of the gas measurement system which exceeds contractual tolerances.

Gas volume statement—a monthly statement showing gas measurement data, including the volume (Mcf) and quality (Btu) of natural gas which flowed through a meter.

Inventory tank—a tank in which liquid hydrocarbons are stored prior to royalty measurement. The measured volumes are used in the allocation process.

Liquid hydrocarbons (free liquids)—hydrocarbons which exist in liquid form at standard conditions after passing through separating facilities.

Malfunction factor—a liquid hydrocarbon royalty meter factor that differs from the previous meter factor by an amount greater than 0.0025.

Natural gas—a highly compressible, highly expandable mixture of hydrocarbons which occurs naturally in a gaseous form and passes a meter in vapor phase.

Operating meter—a royalty or allocation meter that is used for gas or liquid hydrocarbon measurement for any period during a calibration cycle.

Pressure base—the pressure at which gas volumes and quality are reported. The standard pressure base is 14.73 psia.

Prove—to determine (as in meter proving) the relationship between the volume passing through a meter at one set of conditions and the indicated volume at those same conditions.

Pipeline (retrograde) condensate—liquid hydrocarbons which drop out of the separated gas stream at any point in a pipeline during transmission to shore.

Royalty meter—a meter approved for the purpose of determining the volume of gas, oil, or other components removed, saved, or sold from a Federal lease.

Royalty tank—an approved tank in which liquid hydrocarbons are measured and upon which royalty volumes are based.

Run ticket—the invoice for liquid hydrocarbons measured at a royalty point.

Sales meter—a meter at which custody transfer takes place (not necessarily a royalty meter).

Seal—a device or approved method used to prevent tampering with royalty measurement components.

Standard conditions—atmospheric pressure of 14.73 pounds per square inch absolute (psia) and 60 °F.

Surface commingling—the surface mixing of production from two or more leases or units prior to measurement for royalty purposes.

Temperature base—the temperature at which gas and liquid hydrocarbon volumes and quality are reported. The standard temperature base is 60 °F.

You or your—the lessee or the operator or other lessees' representative engaged in operations in the Outer Continental Shelf (OCS).

[63 FR 26370, May 12, 1998. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1202 Liquid hydrocarbon measurement.

(a) *What are the requirements for measuring liquid hydrocarbons?* You must:

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing liquid hydrocarbon production or making changes to previously approved measurement procedures;

(2) Use measurement equipment that will accurately measure the liquid hydrocarbons produced from a lease or unit;

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS as incorporated by reference in 30 CFR 250.198, when obtaining net standard volume and associated measurement parameters; and

(4) When requested by the Regional Supervisor, provide the pipeline (retrograde) condensate volumes as allocated to the individual leases or units.

(b) *What are the requirements for liquid hydrocarbon royalty meters?* You must:

(1) Ensure that the royalty meter facilities include the following approved components (or other MMS-approved components) which must be compatible with their connected systems:

(i) A meter equipped with a nonreset totalizer;

(ii) A calibrated mechanical displacement (pipe) prover, master meter, or tank prover;

(iii) A proportional-to-flow sampling device pulsed by the meter output;

(iv) A temperature measurement or temperature compensation device; and

(v) A sediment and water monitor with a probe located upstream of the divert valve.

(2) Ensure that the royalty meter facilities accomplish the following:

(i) Prevent flow reversal through the meter;

(ii) Protect meters subjected to pressure pulsations or surges;

(iii) Prevent the meter from being subjected to shock pressures greater than the maximum working pressure; and

(iv) Prevent meter bypassing.

(3) Maintain royalty meter facilities to ensure the following:

(i) Meters operate within the gravity range specified by the manufacturer;

(ii) Meters operate 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.

(4) Ensure that sampling devices conform to the following:

(i) The sampling point is in the flowstream immediately upstream or downstream of the meter or divert valve (in accordance with the API MPMS as incorporated by reference in 30 CFR 250.198);

(ii) The sample container is vapor-tight and includes a power mixing device to allow complete mixing of the sample before removal from the container; and

(iii) The sample probe is in the center half of the pipe diameter in a vertical run and is located at least three pipe diameters downstream of any pipe fitting within a region of turbulent flow. The sample probe can be located in a horizontal pipe if adequate stream conditioning such as power mixers or static mixers are installed upstream of the probe according to the manufacturer's instructions.

(c) *What are the requirements for run tickets?* You must:

(1) For royalty meters, ensure that the run tickets clearly identify all observed data, all correction factors not included in the meter factor, and the net standard volume.

(2) For royalty tanks, ensure that the run tickets clearly identify all observed data, all applicable correction factors, on/off seal numbers, and the net standard volume.

(3) Pull a run ticket at the beginning of the month and immediately after establishing the monthly meter factor or a malfunction meter factor.

(4) Send all run tickets for royalty meters and tanks to the Regional Supervisor within 15 days after the end of the month;

(d) *What are the requirements for liquid hydrocarbon royalty meter provings?* You must:

(1) Permit MMS representatives to witness provings;

(2) Ensure that the integrity of the prover calibration is traceable to test measures certified by the National Institute of Standards and Technology;

(3) Prove each operating royalty meter to determine the meter factor monthly, but the time between meter factor determinations must not exceed 42 days;

(4) Obtain approval from the Regional Supervisor before proving on a schedule other than monthly; and

(5) Submit copies of all meter proving reports for royalty meters to the Regional Supervisor monthly within 15 days after the end of the month.

(e) *What are the requirements for calibrating a master meter used in royalty meter provings?* You must:

(1) Calibrate the master meter to obtain a master meter factor before using it to determine operating meter factors;

(2) Use a fluid of similar gravity, viscosity, temperature, and flow rate as the liquid hydrocarbons that flow through the operating meter to calibrate the master meter;

(3) Calibrate the master meter monthly, but the time between calibrations must not exceed 42 days;

(4) Calibrate the master meter by recording runs until the results of two consecutive runs (if a tank prover is used) or five out of six consecutive runs (if a mechanical-displacement prover is used) produce meter factor differences of no greater than 0.0002. Lessees must use the average of the two (or the five) runs that produced acceptable results to compute the master meter factor;

(5) Install the master meter upstream of any back-pressure or reverse flow check valves associated with the operating meter. However, the master meter may be installed either upstream or downstream of the operating meter; and

(6) Keep a copy of the master meter calibration report at your field location for 2 years.

(f) *What are the requirements for calibrating mechanical-displacement provers and tank provers?* You must:

(1) Calibrate mechanical-displacement provers and tank provers at least once every 5 years according to the API MPMS as incorporated by reference in 30 CFR 250.101; and

(2) Submit a copy of each calibration report to the Regional Supervisor within 15 days after the calibration.

(g) *What correction factors must I use when proving meters with a mechanical-displacement prover, tank prover, or master meter?* Calculate the following correction factors using the API MPMS as referenced in 30 CFR 250.198:

(1) The change in prover volume due to the effect of temperature on steel (Cts);

(2) The change in prover volume due to the effect of pressure on steel (Cps);

(3) The change in liquid volume due to the effect of temperature on a liquid (Ctl); and

(4) The change in liquid volume due to the effect of pressure on a liquid (Cpl).

(h) *What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?* (1) If you use a mechanical-displacement prover, you must record proof runs until five out of six consecutive runs produce a difference between individual runs of no greater than .05 percent. You must use the average of the five accepted runs to compute the meter factor.

(2) If you use a master meter, you must record proof runs until three consecutive runs produce a total meter factor difference of no greater than 0.0005. The flow rate through the meters during the proving must be within 10 percent of the rate at which the line meter will operate. The final meter factor is determined by averaging the meter factors of the three runs;

(3) If you use a tank prover, you must record proof runs until two consecutive runs produce a meter factor difference of no greater than .0005. The final

meter factor is determined by averaging the meter factors of the two runs; and

(4) You must apply operating meter factors forward starting with the date of the proving.

(i) *Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must I do?* (1) If the difference between the meter factor and the previous factor exceeds 0.0025 it is a malfunction factor, and you must:

(i) Remove the meter from service and inspect it for damage or wear;

(ii) Adjust or repair the meter, and reprove it;

(iii) Apply the average of the malfunction factor and the previous factor to the production measured through the meter between the date of the previous factor and the date of the malfunction factor; and

(iv) Indicate that a meter malfunction occurred and show all appropriate remarks regarding subsequent repairs or adjustments on the proving report.

(2) If a meter fails to register production, you must:

(i) Remove the meter from service, repair and reprove it;

(ii) Apply the previous meter factor to the production run between the date of that factor and the date of the failure; and

(iii) Estimate and report unregistered production on the run ticket.

(3) If the results of a royalty meter proving exceed the run tolerance criteria and all measures excluding the adjustment or repair of the meter cannot bring results within tolerance, you must:

(i) Establish a factor using proving results made before any adjustment or repair of the meter; and

(ii) Treat the established factor like a malfunction factor (see paragraph (i)(1) of this section).

(j) *How must I correct gross liquid hydrocarbon volumes to standard conditions?* To correct gross liquid hydrocarbon volumes to standard conditions, you must:

(1) Include Cpl factors in the meter factor calculation or list and apply them on the appropriate run ticket.

(2) List Ctl factors on the appropriate run ticket when the meter is not automatically temperature compensated.

(k) *What are the requirements for liquid hydrocarbon allocation meters?* For liquid hydrocarbon allocation meters you must:

(1) Take samples continuously proportional to flow or daily (use the procedure in the applicable chapter of the API MPMS as incorporated by reference in 30 CFR 250.198;

(2) For turbine meters, take the sample proportional to the flow only;

(3) Prove allocation meters monthly if they measure 50 or more barrels per day per meter; or

(4) Prove allocation meters quarterly if they measure less than 50 barrels per day per meter;

(5) Keep a copy of the proving reports at the field location for 2 years;

(6) Adjust and reprove the meter if the meter factor differs from the previous meter factor by more than 2 percent and less than 7 percent;

(7) For turbine meters, remove from service, inspect and reprove the meter if the factor differs from the previous meter factor by more than 2 percent and less than 7 percent;

(8) Repair and reprove, or replace and prove the meter if the meter factor differs from the previous meter factor by 7 percent or more; and

(9) Permit MMS representatives to witness provings.

(l) *What are the requirements for royalty and inventory tank facilities?* You must:

(1) Equip each royalty and inventory tank with a vapor-tight thief hatch, a vent-line valve, and a fill line designed to minimize free fall and splashing;

(2) For royalty tanks, submit a complete set of calibration charts (tank tables) to the Regional Supervisor before using the tanks for royalty measurement;

(3) For inventory tanks, retain the calibration charts for as long as the tanks are in use and submit them to the Regional Supervisor upon request; and

(4) Obtain the volume and other measurement parameters by using correction factors and procedures in the

API MPMS as incorporated by reference in 30 CFR 250.198.

[63 FR 26370, May 12, 1998. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 63 FR 33853, June 22, 1998; 64 FR 72794, Dec. 28 1999]

§ 250.1203 Gas measurement.

(a) *To which meters do MMS requirements for gas measurement apply?* MMS requirements for gas measurements apply to all OCS gas royalty and allocation meters.

(b) *What are the requirements for measuring gas?* You must:

(1) Submit a written application to, and obtain approval from, the Regional Supervisor before commencing gas production or making changes to previously approved measurement procedures.

(2) Design, install, use, maintain, and test measurement equipment to ensure accurate and verifiable measurement. You must follow the recommendations in API MPMS as incorporated by reference in 30 CFR 250.198.

(3) Ensure that the measurement components demonstrate consistent levels of accuracy throughout the system.

(4) Equip the meter with a chart or electronic data recorder. If an electronic data recorder is used, you must follow the recommendations in API MPMS as referenced in 30 CFR 250.198.

(5) Take proportional-to-flow or spot samples upstream or downstream of the meter at least once every 6 months.

(6) When requested by the Regional Supervisor, provide available information on the gas quality.

(7) Ensure that standard conditions for reporting gross heating value (Btu) are at a base temperature of 60 °F and at a base pressure of 14.73 psia and reflect the same degree of water saturation as in the gas volume.

(8) When requested by the Regional Supervisor, submit copies of gas volume statements for each requested gas meter. Show whether gas volumes and gross Btu heating values are reported at saturated or unsaturated conditions; and

(9) When requested by the Regional Supervisor, provide volume and quality statements on dispositions other than those on the gas volume statement.

(c) *What are the requirements for gas meter calibrations?* You must:

(1) Calibrate meters monthly, but do not exceed 42 days between calibrations;

(2) Calibrate each meter by using the manufacturer's specifications;

(3) Conduct calibrations as close as possible to the average hourly rate of flow since the last calibration;

(4) Retain calibration reports at the field location for 2 years, and send the reports to the Regional Supervisor upon request; and

(5) Permit MMS representatives to witness calibrations.

(d) *What must I do if a gas meter is out of calibration or malfunctioning?* If a gas meter is out of calibration or malfunctioning, you must:

(1) If the readings are greater than the contractual tolerances, adjust the meter to function properly or remove it from service and replace it.

(2) Correct the volumes to the last acceptable calibration as follows:

(i) If the duration of the error can be determined, calculate the volume adjustment for that period.

(ii) If the duration of the error cannot be determined, apply the volume adjustment to one-half of the time elapsed since the last calibration or 21 days, whichever is less.

(e) *What are the requirements when natural gas from a Federal lease on the OCS is transferred to a gas plant before royalty determination?* If natural gas from a Federal lease on the OCS is transferred to a gas plant before royalty determination:

(1) You must provide the following to the Regional Supervisor upon request:

(i) A copy of the monthly gas processing plant allocation statement; and

(ii) Gross heating values of the inlet and residue streams when not reported on the gas plant statement.

(2) You must permit MMS to inspect the measurement and sampling equipment of natural gas processing plants that process Federal production.

(f) *What are the requirements for measuring gas lost or used on a lease?* (1) You must either measure or estimate the volume of gas lost or used on a lease.

(2) If you measure the volume, document the measurement equipment used and include the volume measured.

(3) If you estimate the volume, document the estimating method, the data used, and the volumes estimated.

(4) You must keep the documentation, including the volume data, easily obtainable for inspection at the field location for at least 2 years, and must retain the documentation at a location of your choosing for at least 7 years after the documentation is generated, subject to all other document retention and production requirements in 30 U.S.C. 1713 and 30 CFR part 212.

(5) Upon the request of the Regional Supervisor, you must provide copies of the records.

[63 FR 26370, May 12, 1998. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 63 FR 33853, June 22, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1204 Surface commingling.

(a) *What are the requirements for the surface commingling of production?* You must:

(1) Submit a written application to, and obtain approval from, the Regional supervisor before commencing the commingling of production or making changes to previously approved commingling applications.

(2) Upon the request of the Regional Supervisor, lessees who deliver State lease production into a Federal commingling system must provide volumetric or fractional analysis data on the State lease production through the designated system operator.

(b) *What are the requirements for a periodic well test used for allocation?* You must:

(1) Conduct a well test at least once every 2 months unless the Regional Supervisor approves a different frequency;

(2) Follow the well test procedures in 30 CFR part 250, Subpart K; and

(3) Retain the well test data at the field location for 2 years.

[63 FR 26370, May 12, 1998. Redesignated at 63 FR 29479, May 29, 1998; 63 FR 33853, June 22, 1998]

§ 250.1205 Site security.

(a) *What are the requirements for site security?* You must:

(1) Protect Federal production against production loss or theft;

(2) Post a sign at each royalty or inventory tank which is used in the royalty determination process. The sign must contain the name of the facility operator, the size of the tank, and the tank number;

(3) Not bypass MMS-approved liquid hydrocarbon royalty meters and tanks; and

(4) Report the following to the Regional Supervisor as soon as possible, but no later than the next business day after discovery:

(i) Theft or mishandling of production;

(ii) Tampering or bypassing any component of the royalty measurement facility; and

(iii) Falsifying production measurements.

(b) *What are the requirements for using seals?* You must:

(1) Seal the following components of liquid hydrocarbon royalty meter installations to ensure that tampering cannot occur without destroying the seal:

(i) Meter component connections from the base of the meter up to and including the register;

(ii) Sampling systems including packing device, fittings, sight glass, and container lid;

(iii) Temperature and gravity compensation device components;

(iv) All valves on lines leaving a royalty or inventory storage tank, including load-out line valves, drain-line valves, and connection-line valves between royalty and non-royalty tanks; and

(v) Any additional components required by the Regional Supervisor.

(2) Seal all bypass valves of gas royalty and allocation meters.

(3) Number and track the seals and keep the records at the field location for at least 2 years; and

(4) Make the records of seals available for MMS inspection.

Subpart M—Unitization

SOURCE: 62 FR 5331, Feb. 5, 1997, unless otherwise noted. Redesignated at 63 FR 29479, May 29, 1998.

§ 250.1300 What is the purpose of this subpart?

This subpart explains how Outer Continental Shelf (OCS) leases are unitized. If you are an OCS lessee, use the regulations in this subpart for both competitive reservoir and unitization situations. The purpose of joint development and unitization is to:

(a) Conserve natural resources;

(b) Prevent waste; and/or

(c) Protect correlative rights, including Federal royalty interests.

§ 250.1301 What are the requirements for unitization?

(a) *Voluntary unitization.* You and other OCS lessees may ask the Regional Supervisor to approve a request for voluntary unitization. The Regional Supervisor may approve the request for voluntary unitization if unitized operations:

(1) Promote and expedite exploration and development; or

(2) Prevent waste, conserve natural resources, or protect correlative rights, including Federal royalty interests, of a reasonably delineated and productive reservoir.

(b) *Compulsory unitization.* The Regional Supervisor may require you and other lessees to unitize operations if unitized operations are necessary to:

(1) Prevent waste;

(2) Conserve natural resources; or

(3) Protect correlative rights, including Federal royalty interests, of a reasonably delineated and productive reservoir.

(c) *Unit area.* The area that a unit includes is the minimum number of leases that will allow the lessees to minimize the number of platforms, facility installations, and wells necessary for efficient exploration, development, and production of mineral deposits, oil and gas reservoirs, or potential hydrocarbon accumulations. A unit may include whole leases or portions of leases.

(d) *Unit agreement.* You, the other lessees, and the unit operator must enter into a unit agreement. The unit agreement must: allocate benefits to unitized leases, designate a unit operator, and specify the effective date of the unit agreement. The unit agreement must terminate when: the unit no longer produces unitized substances, and the unit operator no longer conducts drilling or well-workover operations (§ 250.180) under the unit agreement, unless the Regional Supervisor orders or approves a suspension of production under § 250.170.

(e) *Unit operating agreement.* The unit operator and the owners of working interests in the unitized leases must enter into a unit operating agreement. The unit operating agreement must describe how all the unit participants will apportion all costs and liabilities incurred maintaining or conducting operations. When a unit involves one or more net-profit-share leases, the unit operating agreement must describe how to attribute costs and credits to the net-profit-share lease(s), and this part of the agreement must be approved by the Regional Supervisor. Otherwise, you must provide a copy of the unit operating agreement to the Regional Supervisor, but the Regional Supervisor does not need to approve the unit operating agreement.

(f) *Extension of a lease covered by unit operations.* If your unit agreement expires or terminates, or the unit area adjusts so that no part of your lease remains within the unit boundaries, your lease expires unless:

(1) Its initial term has not expired;

(2) You conduct drilling, production, or well-reworking operations on your lease consistent with applicable regulations; or

(3) MMS orders or approves a suspension of production or operations for your lease.

(g) *Unit operations.* If your lease, or any part of your lease, is subject to a unit agreement, the entire lease continues for the term provided in the lease, and as long thereafter as any portion of your lease remains part of the unit area, and as long as operations continue the unit in effect.

(1) If you drill, produce or perform well-workover operations on a lease within a unit, each lease, or part of a lease, in the unit will remain active in accordance with the unit agreement. Following a discovery, if your unit ceases drilling activities for a reasonable time period between the delineation of one or more reservoirs and the

initiation of actual development drilling or production operations and that time period would extend beyond your lease's primary term or any extension under § 250.180, the unit operator must request and obtain MMS approval of a suspension of production under § 250.170 in order to keep the unit from terminating.

(2) When a lease in a unit agreement is beyond the primary term and the lease or unit is not producing, the lease will expire unless:

(i) You conduct a continuous drilling or well reworking program designed to develop or restore the lease or unit production; or

(ii) MMS orders or approves a suspension of operations under § 250.170.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1302 What if I have a competitive reservoir on a lease?

(a) The Regional Supervisor may require you to conduct development and production operations in a competitive reservoir under either a joint Development and Production Plan or a unitization agreement. A competitive reservoir has one or more producing or producible well completions on each of two or more leases, or portions of leases, with different lease operating interests. For purposes of this paragraph, a producible well completion is a well which is capable of production and which is shut in at the well head or at the surface but not necessarily connected to production facilities and from which the operator plans future production.

(b) You may request that the Regional Supervisor make a preliminary determination whether a reservoir is competitive. When you receive the preliminary determination, you have 30 days (or longer if the Regional Supervisor allows additional time) to concur or to submit an objection with supporting evidence if you do not concur. The Regional Supervisor will make a final determination and notify you and the other lessees.

(c) If you conduct drilling or production operations in a reservoir determined competitive by the Regional Supervisor, you and the other affected lessees must submit for approval a joint plan of operations. You must submit the joint plan within 90 days after the Regional Supervisor makes a final determination that the reservoir is competitive. The joint plan must provide for the development and/or production of the reservoir. You may submit supplemental plans for the Regional Supervisor's approval.

(d) If you and the other affected lessees cannot reach an agreement on a joint Development and Production Plan within the approved period of time, each lessee must submit a separate plan to the Regional Supervisor. The Regional Supervisor will hold a hearing to resolve differences in the separate plans. If the differences in the separate plans are not resolved at the hearing and the Regional Supervisor determines that unitization is necessary under § 250.1301(b), MMS will initiate unitization under § 250.1304.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998]

§ 250.1303 How do I apply for voluntary unitization?

(a) You must file a request for a voluntary unit with the Regional Supervisor. Your request must include:

(1) A draft of the proposed unit agreement;

(2) A proposed initial plan of operation;

(3) Supporting geological, geophysical, and engineering data; and

(4) Other information that may be necessary to show that the unitization proposal meets the criteria of § 250.1300.

(b) The unit agreement must comply with the requirements of this part. MMS will maintain and provide a model unit agreement for you to follow. If MMS revises the model, MMS will publish the revised model in the FEDERAL REGISTER. If you vary your unit agreement from the model agreement, you must obtain the approval of the Regional Supervisor.

(c) After the Regional Supervisor accepts your unitization proposal, you, the other lessees, and the unit operator must sign and file copies of the unit agreement, the unit operating agreement, and the initial plan of operation with the Regional Supervisor for approval.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1304 How will MMS require unitization?

(a) If the Regional Supervisor determines that unitization of operations within a proposed unit area is necessary to prevent waste, conserve natural resources of the OCS, or protect correlative rights, including Federal royalty interests, the Regional Supervisor may require unitization.

(b) If you ask MMS to require unitization, you must file a request with the Regional Supervisor. You must include a proposed unit agreement as described in §§ 250.1301(d) and 250.1303(b); a proposed unit operating agreement; a proposed initial plan of operation; supporting geological, geophysical, and engineering data; and any other information that may be necessary to show that unitization meets the criteria of § 250.1300. The proposed unit agreement must include a counterpart executed by each lessee seeking compulsory unitization. Lessees who seek compulsory unitization must simultaneously serve on the nonconsenting lessees copies of:

(1) The request;

(2) The proposed unit agreement with executed counterparts;

(3) The proposed unit operating agreement; and

(4) The proposed initial plan of operation.

(c) If the Regional Supervisor initiates compulsory unitization, MMS will serve all lessees of the proposed unit area with a proposed unitization plan and a statement of reasons for the proposed unitization.

(d) The Regional Supervisor will not require unitization until MMS provides all lessees of the proposed unit area written notice and an opportunity for a hearing. If you want MMS to hold a hearing, you must request it within 30 days after you receive written notice from the Regional Supervisor or after you are served with a request for compulsory unitization from another lessee.

(e) MMS will not hold a hearing under this paragraph until at least 30 days after MMS provides written notice of the hearing date to all parties owning interests that would be made subject to the unit agreement. The Regional Supervisor must give 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. The Regional Supervisor will make a decision based upon a record of the hearing, including any written information made a part of the record. The Regional Supervisor will arrange for a court reporter to make a verbatim transcript. The party seeking compulsory unitization must pay for the court reporter and pay for and provide to the Regional Supervisor within 10 days after the hearing three copies of the verbatim transcript.

(f) The Regional Supervisor will issue an order that requires or rejects compulsory unitization. That order must include a statement of reasons for the action taken and identify those parts of the record which form the basis of the decision. Any adversely affected party may appeal the final order of the Regional Supervisor under 30 CFR part 290.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

Subpart N—Outer Continental Shelf (OCS) Civil Penalties

SOURCE: 62 FR 42668, Aug. 8, 1997, unless otherwise noted. Redesignated at 63 FR 29479, May 29, 1998.

§ 250.1400 How does MMS begin the civil penalty process?

This subpart explains MMS's civil penalty procedures whenever a lessee, operator or other person engaged in oil, gas, sulphur or other minerals operations in the OCS has a violation. Whenever MMS determines, on the basis of available evidence, that a violation occurred and a civil penalty review is appropriate, it will prepare a case file. MMS will appoint a Reviewing Officer.

§ 250.1401 Index table.

The following table is an index of the sections in this subpart:

§ 250.1401 TABLE

Definitions	§ 250.1402
What is the maximum civil penalty?	§ 250.1403
Which violations will MMS review for potential civil penalties?	§ 250.1404
When is a case file developed?	§ 250.1405
When will MMS notify me and provide penalty information?	§ 250.1406
How do I respond to the letter of notification?	§ 250.1407
When will I be notified of the Reviewing Officer's decision?	§ 250.1408
What are my appeal rights?	§ 250.1409

[62 FR 42668, Aug. 8, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1402 Definitions.

Terms used in this subpart have the following meaning:

Case file means an MMS document file containing information and the record of evidence related to the alleged violation.

Civil penalty means a fine. It is an MMS regulatory enforcement tool used in addition to Notices of Incidents of Noncompliance and directed suspensions of production or other operations.

I, me in a question or *you* in a response means the person, or agent of a person engaged in oil, gas, sulphur, or other minerals operations in the Outer Continental Shelf (OCS).

Person means, in addition to a natural person, an association (including partnerships and joint ventures), a State, a political subdivision of a State, or a private, public, or municipal corporation.

Reviewing Officer means an MMS employee assigned to review case files and assess civil penalties.

Violation means failure to comply with the Outer Continental Shelf Lands Act (OCSLA) or any other applicable laws, with any regulations issued under the OCSLA, or with the terms or provisions of leases, licenses, permits, rights-of-way, or other approvals issued under the OCSLA.

Violator means a person responsible for a violation.

§ 250.1403 What is the maximum civil penalty?

The maximum civil penalty is $25,000 per day per violation.

[64 FR 9065, Feb. 24, 1999]

§ 250.1404 Which violations will MMS review for potential civil penalties?

MMS will review each of the following violations for potential civil penalties:

(a) Violations that you do not correct within the period MMS grants;

(b) Violations that MMS determines may constitute, or constituted, 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; or

(c) Violations that cause 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.

(d) Violations of the oil spill financial responsibility requirements at 30 CFR part 253.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 63 FR 42711, Aug. 11, 1998; 64 FR 9066, Feb. 24, 1999]

§ 250.1405 When is a case file developed?

MMS will develop a case file during its investigation of the violation, and forward it to a Reviewing Officer if any of the conditions in § 250.1404 exist. The Reviewing Officer will review the case file and determine if a civil penalty is appropriate. The Reviewing Officer may administer oaths and issue subpoenas requiring witnesses to attend meetings, submit depositions, or produce evidence.

[62 FR 42668, Aug. 8, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1406 When will MMS notify me and provide penalty information?

If the Reviewing Officer determines that a civil penalty should be assessed, the Reviewing Officer will send the violator a letter of notification. The letter of notification will include:

(a) The amount of the proposed civil penalty;

(b) Information on the violation(s); and

(c) Instruction on how to obtain a copy of the case file, schedule a meeting, submit information, or pay the penalty.

[62 FR 42668, Aug. 8, 1997. Redesignated at 63 FR 29479, May 29, 1998; 64 FR 9066, Feb. 24, 1999]

§ 250.1407 How do I respond to the letter of notification?

You have 30 calendar days after you receive the Reviewing Officer's letter to either:

(a) Request, in writing, a meeting with the Reviewing Officer;

(b) Submit additional information; or

(c) Pay the proposed civil penalty.

§ 250.1408 When will I be notified of the Reviewing Officer's decision?

At the end of the 30 calendar days or after the meeting and submittal of additional information, the Reviewing Officer will review the case file, including all information you submitted, and send you a decision. The decision will include the amount of any final civil penalty, the basis for the civil penalty, and instructions for paying or appealing the civil penalty.

§ 250.1409 What are my appeal rights?

(a) When you receive the Reviewing Officer's final decision, you have 60 days to either pay the penalty or file an appeal in accordance with 30 CFR part 290, subpart A.

(b) If you file an appeal, you must either:

(1) Submit a surety bond in the amount of the penalty to the Regional Adjudication Office in the Region where the penalty was assessed, following instructions that the Reviewing Officer will include in the final decision; or

(2) Notify the Regional Adjudication Office, in the Region where the penalty was assessed, that you want your lease-specific/area-wide bond on file to be used as the bond for the penalty amount.

(c) If you choose the alternative in paragraph (b)(2) of this section, the Regional Director may require additional security (*i.e.*, security in excess of your existing bond) to ensure sufficient coverage during an appeal. In that event, the Regional Director will require you to post the supplemental bond with the regional office in the same manner as under §§ 256.53(d) through (f) of this chapter. If the Regional Director determines the appeal should be covered by a lease-specific abandonment account then you must establish an account that meets the requirements of § 256.56.

(d) If you do not either pay the penalty or file a timely appeal, MMS will take one or more of the following actions:

(1) We will collect the amount you were assessed, plus interest, late payment charges, and other fees as provided by law, from the date you received the Reviewing Officer's final decision until the date we receive payment;

(2) We may initiate additional enforcement, including, if appropriate, cancellation of the lease, right-of-way, license, permit, or approval, or the forfeiture of a bond under this part; or

(3) We may bar you from doing further business with the Federal Government according to Executive Orders 12549 and 12689, and section 2455 of the Federal Acquisition Streamlining Act of 1994, 31 U.S.C. 6101. The Department of the Interior's regulations implementing these authorities are found at 43 CFR part 12, subpart D.

[64 FR 26257, May 13, 1999, as amended at 65 FR 2875, Jan. 19, 2000]

Subpart O—Training

SOURCE: 62 FR 5322, Feb. 5, 1997, unless otherwise noted. Redesignated at 62 FR 67284, Dec. 24, 1997, and further redesignated at 63 FR 29479, May 29, 1998.

§ 250.1500 Question index table.

The table in this section lists frequently asked training questions and the location for the answers. The subjects are grouped as follows:

(a) General training requirements—§§ 250.1502 through 250.1507.

(b) Departures from training requirements—§§ 250.1508 through 250.1513.

(c) Training program accreditations—§§ 250.1514 through 250.1520 and § 250.1524.

(d) MMS testing information—§§ 250.1521 through 250.1523.

§ 250.1500 TABLE

Frequently asked questions	CFR citation
What is MMS's goal for well control and production safety systems training?	§ 250.1502
What type of training must I provide for my employees?	§ 250.1503
What documentation must I provide to trainees?	§ 250.1504
How often must I provide training to my employees and for how many hours?	§ 250.1505
Where must I get training for my employees?	§ 250.1506
Where can I find training guidelines for other topics?	§ 250.1507
Can I get exception to the training requirements?	§ 250.1508
Can my employees change job certification?	§ 250.1509
What must I do if I have temporary employees or on-the-job trainees?	§ 250.1510
What must manufacturer's representatives in production safety systems do?	§ 250.1511
May I use alternative training methods?	§ 250.1512
What is MMS looking for when it reviews an alternative training program?	§ 250.1513
Who may accredit training organizations to teach?	§ 250.1514
How long is a training organization's accreditation valid?	§ 250.1515
What information must a training organization submit to MMS?	§ 250.1516
What additional requirements must a training organization follow?	§ 250.1517
What are MMS's requirements for the written test?	§ 250.1518
What are MMS's requirements for the hands-on simulator and well test?	§ 250.1519
What elements must a basic course cover?	§ 250.1520
If MMS tests employees at my worksite, what must I do?	§ 250.1521
If MMS tests trainees at a training organization's facility, what must occur?	§ 250.1522
Why might MMS conduct its own tests?	§ 250.1523
Can a training organization lose its accreditation?	§ 250.1524

[62 FR 5322, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29487, 29488, May 29, 1998; 63 FR 34597, June 25, 1998]

§ 250.1501 Definitions.

Terms used in this subpart have the following meaning:

Alternative training methods means self-paced or team-paced training that may use a computer-based system such as compact disc interactive (CDI), compact disc read only memory (CDROM), or Laser Discs.

Completed training means that the trainee successfully met MMS's requirements for that training.

Employees means direct employees and contract employees of lessees.

Floorhands means rotary helpers, derrickmen, or their equivalent.

I or *you* means the lessee or contractor engaged in oil, gas or sulphur operations in the Outer Continental Shelf (OCS).

Installing means both installing the original equipment and replacing the equipment.

Lessee means the person, organization, agent, or designee authorized to explore, develop, and produce leased deposits.

Maintaining means preventive maintenance, routine repair, and replacing defective components.

Operating means testing, adjusting, calibrating, and recording test and calibration results for the equipment.

Production safety systems employee means employees engaged in installing, repairing, testing, maintaining, or operating surface or subsurface safety devices and the platform employee who is responsible for production operations.

Supervisors means the driller, toolpusher, operator's representative, or their equivalent.

Training means a basic or an advanced class in well control for drilling, well completion/well workover, well servicing, and production safety systems.

Training organization means a party approved by MMS to teach well control for drilling, well completion/well workover, and well servicing, and production safety systems.

Well-completion/well-workover (WO) well control includes small tubing operations.

Well-servicing (WS) well control means snubbing and coil tubing.

Well-workover rig means a drilling rig used for well completion/well workover.

§ 250.1502 What is MMS's goal for well control and production safety systems training?

The goal is to ensure that employees who work in the following areas receive training that results in safe and clean operations:

(a) Drilling well control;

(b) WO well control;

(c) WS well control; and

(d) Production safety systems.

§ 250.1503 What type of training must I provide for my employees?

You must provide training for your employees according to the table in this section.

Type of employee	Training requirements	Comments
Drilling floorhand	Drilling well-control course.[1]	
	Complete a well-control drill at the job site within the time limit prescribed by company operating procedures.[2].	You must log the time it took to complete each drill in the driller's log and furnish the time to the floorhand.
	Participate in well-control drills under subpart D of this part.[2].	You must record the date and time it took to complete each drill in the driller's log.
	Receive copy of a drilling well-control manual.[2]	
Drilling supervisor	Drilling well-control course.[1]	
	Qualify to direct well-control operations.[1]	
WO floorhands	WO well-control course.[1]	
	Complete the qualifying test consisting of a well-control drill at the job site within the time limit set by company procedures.[2].	You must record the date and time it took to complete each drill in the operations log.
	Participate in weekly well-control drills under subparts E and F of this part.[2]	
	Receive a well-control manual.[2]	
WO supervisors	WO well-control course.[1]	
	Qualify to direct well-control operations.[1]	
WS work crews	At least one crew member is trained in WS well control.[1].	Trained employee must be in work area at all times during snubbing or coil tubing operations.
	At least one crew member must be qualified to direct well-control operations.[1]	
Production safety systems employees.	Must complete training that enables them to install, test, maintain, & operate subsurface safety devices.[1]	
Employees who work in well completion operations before or during tree installation.	Either WO well-control course or drilling well-control course.[1]	

[1] Employee may not work in the OCS unless this requirement is met.
[2] Employee must complete this requirement before exceeding 6 months of cumulative employment.

§ 250.1504 What documentation must I provide to trainees?

You must give your employees documents that show they have completed the training course(s) required for their job. The employees must carry the documents or keep them at the job site.

§ 250.1505 How often must I provide training to my employees and for how many hours?

(a) You must ensure that applicable employees complete basic or advanced well-control training at least every 2 years. For example, if your employees complete a well-control course on October 31, 1998, they must again complete the training by October 31, 2000.

(b) You must ensure that applicable employees complete basic or advanced production safety systems training at least every 3 years. For example, if your employees complete production safety systems training on October 31, 1998, they must again complete the training by October 31, 2001.

(c) You must ensure that your employees have at least the amount of training listed in the table in §250.1505(c). The maximum number of hours per day of well control or production safety instruction time is 9 hours.

TRAINING HOURS

Basic/advanced course	Surface option, minimum hours	Subsea option, minimum hours [1]	No options, minimum hours
Drilling (D)	28	32	
Well Completion/Workover (WO)	32	36	
Well Servicing (WS)			18
Combination D/WO	40	44	
Combination D/WS	44	48	
Combination WO/WS	48	52	
Combination D/WO/WS	55	59	
Production Safety Systems			30

[1] The subsea option includes the minimum hours from the surface option plus 4 hours.

(d) For the first training course after March 7, 1997, you must ensure that your employee follows the following transition schedule table for well control.

WELL CONTROL TRANSITION

If your employees	Then the employees must
A. Completed a basic course on or after March 7, 1996 or	A. Complete an appropriate basic course within 2 years to maintain certification,[1] or
B. Completed a basic course before March 7, 1996.	B. Complete an appropriate basic course by March 9, 1998 .[2]

[1] Example A: If the effective date of this regulation is November 1, 1996, and your employees completed a basic course in Drilling and Workover/Completion well control on December 9, 1995, your employees must complete a basic Drilling and Workover/Completion well-control course by December 9, 1997.

[2] Example B: If the effective date of this regulation is November 1, 1996, and your employees completed a basic course in Well Servicing [snubbing option] well control on November 15, 1994, your employees must complete a basic course in Well Servicing [snubbing option] by November 1, 1997.

(e) For the first training course after March 7, 1997, you must ensure that your employee follows the following transition schedule table for production.

PRODUCTION TRANSITION

If your employees	Then your employees must
A. Completed a basic course on or after September 7, 1995, or	A. Complete a basic course within 3 years to maintain certification, or
B. Completed a basic course before September 7, 1995.	B. Complete a basic course by September 7, 1998.

(f) After your employee completes the transition training specified in paragraph (d) or (e) of this section, the training cycle will be 2 years for well control and 3 years for production training (as shown in §250.1505 (a) and (b)).

[62 FR 5323, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997. Redesignated at 62 FR 67284, Dec. 24, 1997, further redesignated at 63 FR 29479, May 29, 1998; 63 FR 34597, June 25, 1998]

§ 250.1506 Where must I get training for my employees?

You must provide training by a training organization or program approved by MMS.

§ 250.1507 Where can I find training guidelines for other topics?

You can find guidelines in the subparts shown in the following table:

Topic	Subpart of part 250
Pollution control	C
Crane operations	A
Welding and burning	A
Hydrogen sulfide	D

[62 FR 5322, Feb. 5, 1997. Redesignated at 62 FR 67284, Dec. 24, 1997, and further redesignated at 63 FR 29479, May 29, 1998, as amended at 64 FR 72794, Dec. 28, 1999]

§ 250.1508 Can I get an exception to the training requirements?

MMS may grant an exception to well control or production safety systems training if:

(a) MMS determines that the exception won't jeopardize the safety of your personnel or create a hazard to the environment; and

(b) You need the exception because of unavoidable circumstances that make compliance infeasible or impractical.

§ 250.1509 Can my employees change job certification?

Only if you ensure that the employees complete training for the new job before entering on duty.

§ 250.1510 What must I do if I have temporary employees or on-the-job trainees?

You must ensure that temporary employees and on-the-job trainees complete the appropriate training unless a trained individual is directly supervising the employee.

§ 250.1511 What must manufacturer's representatives in production safety systems do?

A manufacturer's representative who is working on company supplied equipment must:

(a) Receive training by the manufacturer to install, service, or repair the specific safety device or safety systems; and

(b) Have an individual trained in production safety systems (who is also capable of evaluating the impact of the work done) accompany her/him.

§ 250.1512 May I use alternative training methods?

(a) You may receive a 1-year provisional approval from MMS to use alternative training methods that may involve team or self-paced training using a computer-based system.

(b) You may receive up to 3 additional years (4 years total) from MMS to use alternative training methods (through onsite reviews).

§ 250.1513 What is MMS looking for when it reviews an alternative training program?

(a) The alternative training must teach methods to operate equipment that result in safe and clean operations.

(b) MMS will determine, through onsite MMS reviews and unannounced audits during the provisional period, if the:

(1) Training environment is conducive to learning;

(2) Trainees interact effectively with the moderator or training administrator,

(3) Trainees function as a team (for well control only); and

(4) Tests are challenging and cover all important safety concepts and practical procedures to ensure safety.

(c) MMS may also speak with the trainees to determine if the trainees felt the training met their needs for their job.

§ 250.1514 Who may accredit training organizations to teach?

MMS may accredit a training organization or program.

§ 250.1515 How long is a training organization's accreditation valid?

An accreditation is valid for a maximum of 4 years. A training organization may apply to MMS before the fourth anniversary of the effective accreditation date. The training organization must state the changes (additions and deletions) to the last approved training curriculum and plan.

§ 250.1516 What information must a training organization submit to MMS?

(a) Two copies of the detailed plan that includes the:

(1) Curriculum;

(2) Names and credentials of the instructors;

(3) Mailing and street address of the training facility and the location of the records;

(4) Location for the simulator and lecture areas and how the training organization separates the areas;

(5) Presentation methods (video, lecture, film, etc.);

(6) Percentage of time for each presentation method;

(7) Testing procedures and a sample test; and

(8) List of any portions of the course that cover the subsea training option instead of the surface training option.

(b) Two copies of the training manual.

(c) A cross-reference that relates the requirements of this supbart to the elements in the program.

(d) A copy of the handouts.

(e) A copy of the training certificate that includes the following:

(1) Candidate's full name;

(2) Candidate's social security number,

(3) Name of the training school;

(4) Course name (e.g., basic WS well-control course);

(5) Option (surface or subsea);

(6) Training completion date;

(7) Job classification (e.g., drilling supervisor); and

(8) Certificate expiration date.

(f) Course outlines identified by:

(1) Name (e.g., ''WS well-control course'');

(2) Type (basic or advanced); and

(3) Option (surface or subsea).

(g) Time (hours per student) for the following:

(1) Teaching;

(2) Using the simulator (for well control);

(3) Hands-on training (for production safety systems); and

(4) Completing the test (written and simulator).

(h) Special instruction methods for students who respond poorly to conventional training (including oral assistance).

(i) Additional materials (for the advanced training option) such as advanced training techniques or case studies.

(j) Information on the 3–D simulator or test wells:

(1) Capability for surface and/or subsea drilling well control, WO and completion training;

(2) Capability to simulate lost circulation and secondary kicks; and

(3) Types of kicks.

§ 250.1517 What additional requirements must a training organization follow?

(a) The training organization must keep training records for each trainee for 5 years. For example, if a trainee completed a well-control course in 1996, the training organization may destroy the records at the end of the year 2001. The training organization must keep the following trainee record information:

(1) Daily attendance record including complete student sign-in sheet and makeup time;

(2) Written test and retest (including simulator test);

(3) Evaluation of the trainee's simulator test or retest;

(4) ''Kill sheets'' for simulator test or retest; and

(5) Copy of the trainee's certificate.

(b) Keep records of the training program for 5 years. The 5-year timeframe starts with the program approval date. For example, if a training program was accredited in 1995, at the end of the year 2000, the training organization may destroy the records for 1995. Keep the following training record information:

(1) Complete and current training program plan and a technical manual;

(2) A copy of each class roster; and

(3) Copies of schedules and schedule changes.

(c) Supply trainees with current copies of Government regulations on the training subject matter.

(d) Provide a certificate to each trainee who successfully completes training.

(e) Ensure that the subsea training option has an additional 4 hours of training and covers problems in well control when drilling with a subsea blowout preventer (BOP) stack including:

(1) Choke line friction determinations;

(2) Using marine risers;

(3) Riser collapse;

(4) Removing trapped gas from the BOP after controlling a well kick; and

(5) ''U'' tube effect as gas hits the choke line.

(f) Ensure that trainees who are absent from any part of a course make up the missed portion within 14 days after the end of the course before providing a written or simulator test to the trainee.

(g) Ensure that classes contain 18 or fewer candidates.

(h) Furnish a copy of the training program and plan to MMS personnel for their use during an onsite review.

(i) Submit the course schedule to the approving organization after approval of the training program, annually, and before any program changes. The schedule must include the:

(1) Name of the course;

(2) Class dates;

(3) Type of course; and

(4) Course location.

(j) Provide all basic course trainees a copy of the training manual.

(k) Provide all advanced course trainees handouts necessary to update the manuals the trainee has as a result of previous training courses.

(l) When each course ends, send MMS a letter and a class roster. The class roster must contain the following information for each trainee:

(1) Name of training organization;

(2) Course location (e.g., Thibodeaux, Louisiana);

(3) Trainee's full name;

(4) Name of course (e.g., Drilling well control or WS well control);

(5) Course type (i.e., basic or advanced training);

(6) Options (e.g., subsea);

(7) Date trainee completed course;

(8) Name(s) of instructor(s) teaching the course;

(9) The trainee's social security number;

(10) Trainee's employer;

(11) Actual job title of trainee;

(12) Job of each awarded certificate; and

(13) Test scores (including course element scores) for each successful trainee.

(m) Ensure that test scores for combination training have a separate score element for each designation and for each option. For example, training in subsea drilling and in WO would have separate test scores for the drilling, WO, and for the subsea portion.

§ 250.1518 What are MMS's requirements for the written test?

(a) The training organization must:

(1) Administer the test at the training facility;

(2) Use 70 percent as a passing grade for each course element (drilling, well completion, etc.);

(3) Ensure that the tests are confidential and nonrepetitive;

(4) Offer a retest, when necessary, using different questions of equal difficulty;

(5) Allow open-book regulations and a formula sheet (without examples) for well control only; and

(6) Allocate no more than the following amount of time to the minimum instruction time: 1 hour for a single course, 2 hours for a combination of two basic courses, or 2.5 hours for a combination of three or more courses.

(b) A trainee who fails a retest must repeat the training and pass the test in order to work in the OCS in their job classification.

§ 250.1519 What are MMS's requirements for the hands-on simulator and well test?

(a) The training organization must ensure that:

(1) The test simulates a surface BOP (or subsea stack for the subsea option) and the simulator is 3–D with actual gauges and dials.

(2) The instructor runs only one simulator and has a maximum of three students in each team.

(3) The simulator test time allocated to the minimum instruction time is 1

hour per course (i.e., 2 hours for a combination of two basic courses, etc.).

(4) The trainees are able to:

(i) Kill the well before removing the tree;

(ii) Determine slow pump rates;

(iii) Recognize kick warnings signs;

(iv) Shut in a well;

(v) Complete kill sheets;

(vi) Initiate kill procedures;

(vii) Maintain appropriate bottomhole pressure;

(viii) Maintain constant bottomhole pressure;

(ix) Recognize and handle unusual well-control situations;

(x) Control the kick as it reaches the choke line; and

(xi) Determine if kick gas or fluids are removed.

(5) In the subsea option, the trainees are able to:

(i) Determine choke line friction pressures for subsea BOP stacks; and

(ii) Discuss and demonstrate procedures such as circulating the riser and removing trapped gas in a subsea BOP stack.

(6) Offer a retest, when necessary, using different questions of equal difficulty.

(b) A trainee who fails a retest must repeat the training and pass the test to work in the OCS in their job classification.

[62 FR 5326, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997. Redesignated at 62 FR 67284, Dec. 24, 1998]

§ 250.1520 What elements must a basic course cover?

See Table (a) of this section for well control and Table (b) of this section for production safety systems. The checks in Table (a) indicate the required training elements that apply to each job. Tables (a) and (b) follow:

TABLE (A)—WELL CONTROL

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
1. Hands-on:					
Training to operate choke manifold		✔		✔	
Training to operate stand pipe		✔		✔	
Training to operate mud room valves		✔			
2. Care, handling & characteristics of drilling & completion fluids.	✔	✔			
3. Care, handling & characteristics of well completion/well workover fluids & packer fluids.			✔	✔	✔
4. Major causes of uncontrolled fluids from a well including:					
Failure to keep the hole full	✔		✔		
Swabbing effect	✔		✔		
Loss of circulation	✔		✔		
Insufficient drilling fluid density	✔		✔		
Abnormally pressured formations	✔		✔		
Effect of too rapidly lowering of the pipe in the hole	✔		✔		
5. Importance & instructions of measuring the volume of fluid to fill the hole during trips.	✔		✔		
6. Importance & instructions of measuring the volume of fluid to fill the hole during trips including the importance of filing the hole as it relates to shallow gas conditions.	✔				
7. Filling the tubing & casing with fluid to control bottomhole pressure.				✔	
8. Warning signals that indicate kick & conditions that lead to a kick.	✔	✔	✔	✔	
9. Controlling shallow gas kicks and using diverters	✔				
10. At least one bottomhole pressure well control method including conditions unique to a surface subsea BOP stack.	✔		✔		
11. Installing, operating, maintaining & testing BOP & diverter systems.	✔				
12. Installing, operating, maintaining & testing BOP systems.			✔		
13. Government regulations on:					
Emergency shutdown systems					✔
Production safety systems					✔
Drilling procedures	✔				
Wellbore plugging & abandonment	✔		✔		✔

TABLE (A)—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
Pollution prevention & waste management	✔	✔	✔	✔	✔
Well completion & well workover requirements (Subparts E & F of 30 CFR part 250).			✔		✔
14. Procedures & sequentials steps for shutting in a well:					
BOP system	✔		✔		✔
Surface/subsurface safety system					✔
Choke manifold	✔		✔		
15. Well control exercises with a simulator suitable for modeling well completion/well workover.			✔		
16. Well control exercises with a simulator suitable for modeling drilling.	✔				
17. Instructions & simulator or test well experience on organizing & directing a well killing operation.	✔		✔		
18. At least two simulator practice problems (rotate the trainees & have teams of 3 or less members).	✔		✔		
19. Care, operation, & purpose [& installation (for supervisors)] of the well control equipment.	✔	✔	✔	✔	
20. Limitations of the equipment that may wear or be subjected to pressure.	✔		✔		✔
21. Instructions in well control equipment, including:					
Surface equipment	✔		✔		✔
Well completion/well workover, BOP & tree equipment.	✔		✔		✔
Downhole tools & tubulars	✔		✔		
Tubing hanger, back pressure valve (threaded/profile), landing nipples, lock mandrels for corresponding nipples & operational procedures for each, gas lift equipment & running & pulling tools operation.	✔				✔
Packers	✔		✔		
22. Instructions in special tools & systems, such as:					
Automatic shutdown systems (control points, activator pilots, monitor pilots, control manifolds & subsurface systems).					✔
Flow string systems (tubing, mandrels & nipples, flow couplings, blast joints, & sliding sleeves).					✔
Pumpdown equipment (purpose, applications, requirements, surface circulating systems, entry loops & tree connection/flange).					✔
23. Instructions for detecting entry into abnormally pressured formations & warning signals.	✔				
24. Instructions on well completion/well control problems	✔				
25. Well control problems during well completion/well workover including:					
Killing a flow			✔		
Simultaneous drilling, completion & workover operations on the same platform.			✔		
Killing a producing well			✔		
Removing the tree			✔		
26. Calculations on the following:					
Fluid density increase that controls fluid flow into the wellbore.	✔		✔		
Fluid density to pressure conversion & the danger of formation breakdown under the pressure caused by the fluid column especially when setting casing in shallow formations.	✔				
Fluid density to pressure conversion & the danger of formation breakdown under the pressure caused by fluid column.			✔		
Equivalent pressures at the casing seat depth	✔				
Drop in pump pressure as fluid density increases; & the relationship between pump pressure, pump rate, & fluid density.	✔		✔		
Pressure limitations on casings	✔		✔		
Hydrostatic pressure & pressure gradient	✔		✔		
27. Unusual well control situations, including the following:					
Drill pipe is off the bottom or out of the hole/work string is off the bottom or out of the hole.	✔		✔		
Lost circulation occurs	✔		✔		

TABLE (A)—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
Drill pipe is plugged/work string is plugged	✔		✔		
There is excessive casing pressure	✔		✔		
There is a hole in drill pipe/hole in the work string/ hole in the casing string.	✔		✔		
Multiple completions in the hole			✔		
28. Special well-control problems-drilling with a subsea stack (subsea students) includes:					
Choke line friction determinations	✔		✔		
Using marine risers	✔		✔		
Riser collapse	✔		✔		
Removing trapped gas from the BOP stack after controlling a well kick.	✔		✔		
''U'' tube effect as gas hits the choke line	✔		✔		
29. Mechanics of various well controlled situations, including:					
Gas bubble migration & expansion	✔		✔		
Bleeding volume from a shut-in well during gas migration.	✔		✔		
Excessive annular surface pressure	✔		✔		
Differences between a gas kick & a salt water and/ or oil kick.	✔		✔		
Special well control techniques (such as, but not limited to, barite plugs & cement plugs).	✔		✔		
Procedures & problems involved when experiencing lost circulation.	✔		✔		
Procedures & problems involved when experiencing a kick while drilling in a hydrogen sulfide (H_2S) environment.	✔		✔		✔
Procedures & problems—experiencing a kick during snubbing, coil-tubing, or small tubing operations and stripping & snubbing operations with work string.	✔		✔		
30. Reasons for well completion/well workover, including:					
Reworking a reservoir to control production			✔		✔
Water coning			✔		
Completing from a new reservoir			✔		✔
Completing multiple reservoirs			✔		✔
Stimulating to increase production			✔		✔
Repairing mechanical failure			✔		✔
31. Methods on preparing a well for entry:					
Using back pressure valves			✔		
Using surface & subsurface safety systems			✔		✔
Removing the tree & tubing hangar			✔	✔	✔
Installing & testing BOP & wellhead prior to removing back pressure valves & tubing plugs.			✔		✔
32. Instructions in small tubing units:					
Applications (stimulation operations, cleaning out tubing obstructions, and plugback and squeeze cementing).			✔		
Equipment description (derrick & drawworks, small tubing, pumps, weighted fluid facilities, and weighted fluids).			✔		
BOP equipment (rams, wellhead connection, and check valve).			✔		
33. Methods for killing a producing well, including:					
Bullheading			✔		✔
Lubricating & bleeding			✔		✔
Coil tubing			✔		✔
Applications (stimulation operations, initiating flow, & cleaning out sand in tubing).					✔
Equipment description (coil tubing, reel, injecting head, control assembly & injector hoist).					✔
BOP equipment (tree connection or flange, rams, injector assembly & circulating system).					✔
Snubbing			✔		✔
Types (rig assist & stand alone)					✔
Applications (running & pulling production or kill strings, resetting weight on packers, fishing for lost wireline tools or parted kill strings & circulating cement or fluid).					✔

TABLE (A)—WELL CONTROL—Continued

Elements for basic training	Drilling		WO		WS
	Super	Floor	Super	Floor	
Equipment (operating mechanism, power supply, control assembly & basket, slip assembly, mast & counterbalance winch & access window).					✔
BOP equipment (tree connection or flange, rams, spool, traveling slips, manifolds, auxiliary—full opening safety valve inside BOP, maintenance & testing).					✔
34. The purpose & use of BOP closing units, including the following:					
Charging procedures include precharge & operating pressure.	✔		✔		
Fluid volumes (useable & required)	✔		✔		
Fluid pumps	✔		✔		
Maintenance that includes charging fluid & inspection procedures.	✔		✔		
35. Instructions on stripping & snubbing operators & using the BOP system for working pipe in or out of a wellbore under pressure.	✔				

TABLE (B)—PRODUCTION SAFETY SYSTEMS

1. Government Regulations:
    - Pollution prevention & waste management
    - Requirements for well completion/well workover operations
2. Instructions in the following: (contained in, but not limited to, API RP 14C):
    - Failures or malfunctions in systems that cause abnormal conditions & the detection of abnormal conditions
    - Primary & secondary protection devices & procedures
    - Safety devices that control undesirable events
    - Safety analysis concepts
    - Safety analysis of each basic production process component
    - Protection concepts
3. Hands on training on safety devices covering, installing, operating, repairing or maintaining equipment:
    - High-low pressure sensors
    - High-low level sensors
    - Combustible gas detectors
    - Pressure relief devices
    - Flow line check valves
    - Surface safety valves
    - Shutdown valves
    - Fire (flame, heat, or smoke) detectors
    - Auxiliary devices (3-way block & bleed valves, time relays, 3-way snap acting valves, etc.)
    - Surface-controlled subsurface safety valves &/or surface-control equipment
    - Subsurface-controlled subsurface safety valves
4. Instructions on inspecting, testing & maintaining surface & subsurface devices & surface control systems for subsurface safety valves
5. Instructions in at least one safety device that illustrates the primary operation principle in each class for safety devices:
    - Basic operations principles
    - Limits affecting application
    - Problems causing equipment malfunction & how to correct these problems
    - A test for proper actuation point & operation
    - Adjustments or calibrations
    - Recording inspection results & malfunctions
    - Special techniques for installing safety devices
6. Instructions on the basic principle & logic of the emergency support system:
    - Combustible & toxic gas detection system
    - Liquid containment system
    - Fire loop System
    - Other fire detection systems
    - Emergency shutdown system
    - Subsurface safety valves

[62 FR 5326, Feb. 5, 1997, as amended at 62 FR 7298, Feb. 18, 1997. Redesignated at 62 FR 67284, Dec. 24, 1998]

§ 250.1521 If MMS tests employees at my worksite, what must I do?

(a) You must allow MMS to test employees at your worksite.

(b) You must identify your employees by:

(1) Current job classification;

(2) Name of the operator;

(3) Name of the most recent basic or advanced course taken by your employees for their current job; and

(4) Name of the training organization.

(c) You must correct any deficiencies found by MMS. Steps for correcting deficiencies may include:

(1) Isolating problems by doing more testing; and

(2) Reassigning employees or conducting training (MMS will not identify the employees it tests).

§ 250.1522 If MMS test trainees at a training organization's facility, what must occur?

(a) Training organizations must allow MMS to test trainees.

(b) The trainee must pass the MMS-conducted test or a retest in order for MMS to consider that the trainee completed the training.

§ 250.1523 Why might MMS conduct its own tests?

MMS needs to identify the effectiveness of a training program that provides for safe and clean operations.

§ 250.1524 Can a training organization lose its accreditation?

Yes, an accredited organization can lose its accreditation. MMS may revoke or suspend an organization's accreditation for noncompliance with regulations or conditions of its accredited program, or assess civil penalties under subpart N of this part.

Subpart P—Sulphur Operations

SOURCE: 56 FR 32100, July 15, 1991, unless otherwise noted. Redesignated at 63 FR 29479, May 29, 1998.

§ 250.1600 Performance standard.

Operations to discover, develop, and produce sulphur in the OCS shall be in accordance with an approved Exploration Plan or Development and Production Plan and 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 or not leased), the national security or defense, and the marine, coastal, or human environment.

§ 250.1601 Definitions.

Terms used in this subpart shall have the meanings as defined below:

Air line means a tubing string that is used to inject air within a sulphur producing well to airlift sulphur out of the well.

Bleedwater means a mixture of mine water or booster water and connate water that is produced by a bleedwell.

Bleedwell means a well drilled into a producing sulphur deposit that is used to control the mine pressure generated by the injection of mine water.

Brine means the water containing dissolved salt obtained from a brine well by circulating water into and out of a cavity in the salt core of a salt dome.

Brine well means a well drilled through cap rock into the core at a salt dome for the purpose of producing brine.

Cap rock means the rock formation, a body of limestone, anhydride, and/or gypsum, overlying a salt dome.

Sulphur deposit means a formation of rock that contains elemental sulphur.

Sulphur production rate means the number of long tons of sulphur produced during a certain period of time, usually per day.

§ 250.1602 Applicability.

(a) The requirements of this subpart P are applicable to all exploration, development, and production operations under an OCS sulphur lease. Sulphur operations include all activities conducted under a lease for the purpose of discovery or delineation of a sulphur deposit and for the development and production of elemental sulphur. Sulphur operations also include activities conducted for related purposes. Activities conducted for related purposes include, but are not limited to, production of other minerals, such as salt, for use in the exploration for or the development and production of sulphur. The lessee must have obtained the right to produce and/or use these other minerals.

(b) Lessees conducting sulphur operations in the OCS shall comply with the requirements of the applicable provisions of subparts A, B, C, G, I, J, M, N, and O of this part.

(c) Lessees conducting sulphur operations in the OCS are also required to comply with the requirements in the applicable provisions of subparts D, E, F, H, K, and L of this part where such provisions specifically are referenced in this subpart.

§ 250.1603 Determination of sulphur deposit.

(a) Upon receipt of a written request from the lessee, the District Supervisor will determine whether a sulphur deposit has been defined that contains sulphur in paying quantities (i.e., sulphur in quantities sufficient to yield a return in excess of the costs, after completion of the wells, of producing minerals at the wellheads).

(b) A determination under paragraph (a) of this section shall be based upon the following:

(1) Core analyses that indicate the presence of a producible sulphur deposit (including an assay of elemental sulphur);

(2) An estimate of the amount of recoverable sulphur in long tons over a specified period of time; and

(3) Contour map of the cap rock together with isopach map showing the extent and estimated thickness of the sulphur deposit.

§ 250.1604 General requirements.

Sulphur lessees shall comply with requirements of this section when conducting well-drilling, well-completion, well-workover, or production operations.

(a) *Equipment movement.* The movement of well-drilling, well-completion, or well-workover rigs and related equipment on and off an offshore platform, or from one well to another well on the same offshore platform, including rigging up and rigging down, shall be conducted in a safe manner.

(b) *Hydrogen sulfide (H_2S).* When a drilling, well-completion, well-workover, or production operation is being conducted on a well in zones known to contain H_2S or in zones where the presence of H_2S is unknown (as defined in 30 CFR 250.417 of this part), the lessee shall take appropriate precautions to protect life and property, especially during operations such as dismantling wellhead equipment and flow lines and circulating the well. The lessee shall also take appropriate precautions when H_2S is generated as a result of sulphur production operations. The lessee shall comply with the requirements in § 250.417 of this part as well as the requirements of this subpart.

(c) *Welding and burning practices and procedures.* All welding, burning, and hot-tapping activities involved in drilling, well-completion, well-workover or production operations shall be conducted with properly maintained equipment, trained personnel, and appropriate procedures in order to minimize the danger to life and property according to the specific requirements in § 250.402 of this part.

(d) *Electrical requirements.* All electrical equipment and systems involved in drilling, well-completion, well-workover, and production operations shall be designed, installed, equipped, protected, operated, and maintained so as to minimize the danger to life and property in accordance with the requirements of § 250.403 of this part.

(e) *Structures on fixed OCS platforms.* Derricks, cranes, 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. Prior to moving equipment such as a well-drilling, well-completion, or well-workover rig or associated equipment or production equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and operations, taking into consideration corrosion protection, platform age, and previous stresses.

(f) *Traveling-block safety device.* After August 14, 1992, all drilling units being used for drilling, well-completion, or well-workover operations that have both a traveling block and a crown block shall be equipped with a safety device that 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.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1605 Drilling requirements.

(a) Lessees of OCS sulphur leases shall conduct drilling operations in accordance with §§ 250.1605 through 250.1619 of this subpart and with other requirements of this part, as appropriate.

(b) *Fitness of drilling unit.* (1) Drilling units shall be capable of withstanding the oceanographic and meteorological conditions for the proposed season and location of operations.

(2) Prior to commencing operation, drilling units shall be made available for a 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–123, Application for Permit to Drill (APD), in accordance with § 250.1617 of this subpart. After a drilling unit has been approved by an MMS district office, the information required in this paragraph need not be resubmitted unless required by the District Supervisor or there are changes in the equipment that affect the rated capacity of the unit.

(c) *Oceanographic, meteorological, and drilling unit performance data.* Where oceanographic, meteorological, and drilling unit performance data are not otherwise readily available, lessees shall collect and report such data upon request to the District Supervisor. The type of information to be collected and reported will be determined by the District Supervisor in the interests of safety in the conduct of operations and the structural integrity of the drilling unit.

(d) *Foundation requirements.* When the lessee fails to provide sufficient information pursuant to §§ 250.203 and 250.204 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 submitted for review and evaluation by the District Supervisor before approval is granted for commencing drilling operations.

(e) *Tests, surveys, and samples.* (1) Lessees shall drill and take cores and/or run well and mud logs through the objective interval to determine the presence, quality, and quantity of sulphur and other minerals (e.g., oil and gas) in the cap rock and the outline of the commercial sulphur deposit.

(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 directionally drilled wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 200 feet in all planned angle-change portions of the borehole.

(3) Directional surveys giving both inclination and azimuth shall be obtained on both vertically and directionally drilled wells at intervals not exceeding 500 feet prior to or upon setting a string of casing, or production liner, and at total depth. Composite directional surveys shall be prepared with the interval shown from the bottom of the conductor casing. 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 directional survey will be acceptable as fulfilling the applicable requirements of this paragraph.

(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) At the request of a holder of an adjoining lease, the Regional Supervisor may, for the protection of correlative rights, furnish a copy of the directional survey 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 that have their jacking equipment removed or have been otherwise immobilized are classified as fixed bottom founded drilling platforms.

(g) *Crane operations.* You must operate a crane installed on fixed platforms according to § 250.108 of this subpart.

(h) *Diesel-engine air intakes.* After August 14, 1992, diesel-engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended shall be equipped with either remote-operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended shall be equipped with automatic shutdown devices.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 63 FR 34597, June 25, 1998; 65 FR 15864, Mar. 24, 2000]

§ 250.1606 Control of wells.

The lessee shall take necessary precautions to keep its wells under control at all times. Operations shall be conducted in a safe and workmanlike manner. The lessee shall utilize the best available and safest drilling technologies and state-of-the-art methods to evaluate and minimize the potential for a 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.

§ 250.1607 Field rules.

When geological and engineering information in a field enables a District Supervisor to determine specific operating requirements, field rules may be established for drilling, well completion, or well workover 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 rules have been established, operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field 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.

§ 250.1608 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the several casing strings in order of normal installation are:

(i) Drive or structural,

(ii) Conductor,

(iii) Cap rock casing,

(iv) Bobtail cap rock casing (required when the cap rock casing does not penetrate into the cap rock),

(v) Second cap rock casing (brine wells), and

(vi) Production liner.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing cemented in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into the sea, 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 160 pounds per square inch (psi).

(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 drilling and casing program designs shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well.

(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 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. If the test indicates inadequate cementing, the lessee shall initiate remedial action as approved by the District Supervisor. For cap rock casing, the test for adequacy of cementing shall be the pressure testing of the annulus between the cap rock and the conductor casings. The pressure shall not exceed 70 percent of the burst pressure of the conductor casing or 70 percent of the collapse pressure of the cap rock casing.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth of 100 feet below the mud line or such other depth, as may be required 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 cap rock casing setting and cementing requirements.* (1) Conductor and cap rock 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 proposed casing setting depths may be varied, subject to District Supervisor approval, to permit the casing to be set in a competent formation or through formations determined desirable to 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 unknown, upon encountering such formations. Cap rock casing shall be set and cemented through formations known to contain oil or gas or, if unknown, upon encountering such formations. Upon encountering unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval.

(2) Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line. Cement fill 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) Cap rock 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, cap rock casing shall be cemented with a quantity of cement that fills the calculated annular space to the mud line, unless otherwise approved by the District Supervisor. In brine wells, the second cap rock casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet above the setting depth of the first cap rock casing.

(d) *Bobtail cap rock casing setting and cementing requirements.* (1) Bobtail cap rock casing shall be set on or just in cap rock and lapped a minimum of 100 feet into the previous casing string.

(2) Sufficient cement shall be used to fill the annular space to the top of the bobtail cap rock casing.

(e) *Production liner setting and cementing requirements.* (1) Production liners for sulphur wells and bleedwells shall be set in cap rock at or above the bottom of the open hole (hole that is open in cap rock, below the bottom of the cap rock casing) and lapped into the previous casing string or to the surface. For brine wells, the liner shall be set in salt and lapped into the previous casing string or to the surface.

(2) The production liner is not required to be cemented unless the cap rock contains oil or gas. If the cap rock contains oil or gas, sufficient cement shall be used to fill the annular space to the top of the production liner.

§ 250.1609 Pressure testing of casing.

(a) Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure tested. The conductor casing shall be tested to at least 200 psi. All casing strings below the conductor casing shall be tested to 500 psi or 0.22 psi/ft, whichever is greater. (When oil or gas is not present in the cap rock, the production liner need not be cemented in place; thus, it would not be subject to pressure testing.) 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 tested again. The above procedures shall be repeated until a satisfactory test is obtained. The time, conditions of testing, and results of all casing pressure tests shall be recorded in the driller's report.

(b) After cementing any string of casing other than structural, drilling shall not be resumed until there has been a timelapse of at least 8 hours under pressure for the conductor casing string or 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.

§ 250.1610 Blowout preventer systems and system components.

(a) *General.* The blowout preventer (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) and (f) of this section. The pipe rams shall be of proper size to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP shall exceed the surface pressure to which it may be anticipated to be subjected.

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system that provides sufficient capacity to supply 1.5 times the volume 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. After February 14, 1992, accumulator regulators supplied by rig air, which do not have a secondary source of pneumatic supply, shall be equipped with manual overrides or other devices alternately provided to ensure capability of hydraulic operations if rig air is lost.

(2) An automatic backup to the accumulator system. The backup system shall be supplied by a power source independent from the power source to the primary accumulator system. The automatic backup system shall possess sufficient capability to close the BOP and hold it 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) A choke line and a kill line each equipped with two full-opening valves. At least one of the valves on the choke line and one valve 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 that two readily accessible manual valves are in place and the check valve is placed between the manual valve and the pump.

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

(7) A choke manifold designed with consideration of 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 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 a pressure rating at least as great as the rated working pressure of the ram-type BOP's unless otherwise approved by the District Supervisor.

(9) A wellhead assembly with a rated working pressure that exceeds the pressure to which it might be subjected.

(10) The following system components:

(i) A kelly cock (an essentially full-opening valve) installed below the swivel and a similar valve of such design that it can be run through the BOP stack installed at the bottom of the kelly. A wrench to fit each valve 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; and

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

(e) *BOP requirements.* Prior to drilling below cap rock casing, a BOP system shall be installed consisting of at least three remote-controlled, hydraulically operated BOP's including at least one equipped with pipe rams, one with blind rams, and one annular type.

(f) *Tapered drill-string operations.* Prior to commencing tapered drill-string operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams to provide either of the following:

(1) One set of variable bore rams capable of sealing around both sizes in the string and one set of blind rams, or

(2) One set of pipe rams capable of sealing around the larger size string, provided that blind-shear ram capability is present, and crossover subs to the larger size pipe are readily available on the rig floor.

§ 250.1611 Blowout preventer systems tests, actuations, inspections, and maintenance.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) 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. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Supervisor.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

(1) When installed;

(2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system 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 a stuck drill pipe

or there are 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 date, time, and 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) Bind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than 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 bottomhole tools; and

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly. In this situation, the pressure tests may be limited to the affected component.

(e) All BOP systems shall be inspected and maintained to assure that the equipment will function properly. The BOP systems shall be visually inspected at least once each day. The manufacturer's recommended inspection and maintenance procedures are acceptable as guidelines in complying with this requirement.

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system and system components shall be recorded in the driller's report. The BOP tests shall be documented in accordance with the following:

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

(2) The control station used during the test shall be identified in the driller's report.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the driller's report.

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections, shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

§ 250.1612 Well-control drills.

Well-control drills shall be conducted for each drilling crew in accordance with the requirements set forth in § 250.408 of this part or as approved by the District Supervisor.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1613 Diverter systems.

(a) When drilling a conductor or cap rock hole, all drilling units shall be equipped with a diverter system consisting of a diverter sealing element, diverter lines, and control systems. 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) After August 14, 1992, diverter systems shall be in compliance with the requirements of this section.

The requirements applicable to diverters that were in effect immediately prior to August 14, 1991, shall remain in effect until August 14, 1992.

(c) The diverter system shall be equipped with remote-control valves in the flow 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 valves shall be installed in any part of a 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. 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 vibrations. All diverter control equipment 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 if each outlet has a minimum internal diameter of 8 inches, and 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) The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nippled upon conductor casing. No more than 7 days shall elapse between subsequent pressure tests. The diverter sealing element, diverter valves, and diverter control systems (including the remote) shall be actuation tested, and the diverter lines shall be tested for flow prior to spudding and thereafter at least once each 24-hour period alternating between control stations. All test times and results shall be recorded in the driller's report.

§ 250.1614 Mud program.

(a) 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) The lessee shall comply with requirements concerning mud control, mud test and monitoring equipment, mud quantities, and safety precautions in enclosed mud handling areas as prescribed in § 250.410 (b), (c), (d), and (e) of this part, except that the installation of an operable degasser in the mud system as required in § 250.410(b)(8) is not required for sulphur operations.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1615 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 that force evacuation of the drilling crew, prevent station keeping, or require repairs to major drilling units or well-control equipment. 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 cap rock casing has been set.

§ 250.1616 Supervision, surveillance, and training.

(a) The lessee shall provide onsite supervision of drilling operations at all times.

(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. Records of specific training that 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.

§ 250.1617 Application for permit to drill.

(a) Prior to commencing the drilling of a well under an approved Exploration Plan, Development and Production Plan, or Development Operations

Coordination Document, the lessee shall file Form MMS–123, 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 has been given pursuant to § 250.140 of this part.

(b) An APD shall include rated capacities of the proposed drilling unit and of major drilling equipment. After a drilling unit has been approved for use in an MMS district, the information need not be resubmitted unless required by the District Supervisor or there are changes in the equipment that affect the rated capacity of the unit.

(c) An APD shall include a fully completed Form MMS–123 and the following:

(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. For development wells on a lease, the wells previously drilled in the vicinity need not be shown on the plat. Locations shall be indicated in feet from the nearest block line;

(2) The design criteria considered for the well and for well control, including the following:

(i) Pore pressure;

(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 that can reasonably be expected to be exerted upon a casing string and its related wellhead equipment). In the calculation of 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, and cementing intervals, 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 pressure the calculations used to determine this pressure during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design; and

(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.

(3) A BOP equipment program including the following:

(i) The pressure rating of BOP equipment,

(ii) 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 personnel, and

(iii) 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, and

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

(5) The drilling prognosis including the following:

(i) Estimated coring intervals,

(ii) Estimated depths to the top of significant marker formations, and

(iii) Estimated depths at which encounters with fresh water, sulphur, 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) An H_2S Contingency Plan, if applicable, and if not previously submitted; and

(10) Such other information as may be required by the District Supervisor.

(d) Public information copies of the APD shall be submitted in accordance with § 250.190 of this part.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1618 Sundry notices and reports on wells.

(a) Notices of the lessee's intention to change plans, make changes in major drilling equipment, deepen, sidetrack, 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–124, Sundry Notices and Reports on Wells. Prior to commencing operations associated with the change, written approval must be received from the District Supervisor unless oral approval is obtained pursuant to § 250.140 of this part.

(b) The Form MMS–124 submittal shall contain a detailed statement of the proposed work that will materially change from the work described in the approved APD. Information submitted shall include the present state of the well, including the production liner and last string of casing, the well depth and production zone, and the well's capability to produce. 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) Public information copies of Form MMS–124 shall be submitted in accordance with § 250.117 of this part.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1619 Well records.

(a) Complete and accurate records for each well and 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 sulphur in each formation if cored and analyzed; 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, prevention of waste, conservation of natural resources, protection of correlative rights, safety of operations, and environmental protection.

(b) When drilling operations are suspended or temporarily prohibited under the provisions of § 250.170 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–125, Well Summary Report, or Form MMS–124, Sundry Notices and Reports on Wells, 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) Copies of the 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, mud weights, lost returns, and any unusual activities; and

(3) Legible, exact copies of reports on cementing, acidizing, analyses of cores, testing, or other similar services.

(d) As soon as available, the lessee shall transmit copies of logs and charts developed by well-logging operations, directional-well surveys, and core analyses. 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 such operations for each well.

(e) If the District Supervisor determines that circumstances warrant, the lessee shall submit any other reports and records of operations in the manner and form prescribed by the District Supervisor.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 64 FR 72794, Dec. 28, 1999]

§ 250.1620 Well-completion and well-workover requirements.

(a) Lessees shall conduct well-completion and well-workover operations in sulphur wells, bleedwells, and brine wells in accordance with §§ 250.1620 through 250.1626 of this part and other provisions of this part as appropriate (see §§ 250.501 and 250.601 of this part for the definition of well-completion and well-workover operations).

(b) Well-completion and 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 OCS including any mineral deposits (in areas leased and not leased), the national security or defense, or the marine, coastal, or human environment.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1621 Crew instructions.

Prior to engaging in well-completion or 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 for MMS review.

§ 250.1622 Approvals and reporting of well-completion and well-workover operations.

(a) No well-completion or well-workover operation shall begin until the lessee receives written approval from the District Supervisor. Approval for such operations shall be requested on Form MMS–124. Approvals by the District Supervisor shall be based upon a determination that the operations will be conducted in a manner to protect against harm or damage to life, property, natural resources of the OCS, including any mineral deposits, the national security or defense, or the marine, coastal, or human environment.

(b) The following information shall be submitted with Form MMS–124 (or with Form MMS–123):

(1) A brief description of the well-completion or well-workover procedures to be followed;

(2) When changes in existing subsurface equipment are proposed, a schematic drawing showing the well equipment; and

(3) Where the well is in zones known to contain H_2S or zones where the presence of H_2S is unknown, a description of the safety precautions to be implemented.

(c)(1) Within 30 days after completion, Form MMS–125, including a schematic of the tubing and the results of any well tests, shall be submitted to the District Supervisor.

(2) Within 30 days after completing the well-workover operation, except routine operations, Form MMS–124 shall be submitted to the District Supervisor and shall include the results of any well tests and a new schematic of the well if any subsurface equipment has been changed.

[56 FR 32100, July 15, 1991, as amended at 58 FR 49928, Sept. 24, 1993. Redesignated at 63 FR 29479, May 29, 1998]

§ 250.1623 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 ccntinuously monitored during well-completion and well-workover 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 or a workover string, the annulus shall be filled with well-control fluid before the change in fluid level decreases the hydrostatic pressure 75 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 hole shall be utilized.

§ 250.1624 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 of the BOP system and system components shall equal or exceed the expected surface pressure to which they may be subjected.

(b) The minimum BOP stack for well-completion operations or for well-workover operations with the tree removed shall consist of the following:

(1) Three remote-controlled, hydraulically operated preventers including at least one equipped with pipe rams, one with blind rams, and one annular type.

(2) When a tapered string is used, the minimum BOP stack shall consist of either of the following:

(i) An annular preventer, one set of variable bore rams capable of sealing around both sizes in the string, and one set of blind rams; or

(ii) An annular preventer, one set of pipe rams capable of sealing around the larger size string, a preventer equipped with blind-shear rams, and a crossover sub to the larger size pipe that shall be readily available on the rig floor.

(c) The BOP systems for well-completion operations, or for well-workover operations with the tree removed, shall be equipped with the following:

(1) An accumulator system that provides sufficient capacity to supply 1.5 times the volume 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. After February 14, 1992, accumulator regulators supplied by rig air which do not have 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) An automatic backup to the accumulator system supplied by a power source independent from the power source to the primary accumulator system and possessing sufficient capacity to close all BOP's 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. One of the choke-line valves and one of the kill-line valves shall be remotely controlled except that a check valve may be installed on the kill line in lieu of the remotely-controlled valve provided that two readily accessible manual valves are in place, and the check valve is placed between the manual valve and the pump.

(d) The minimum BOP-stack components for well-workover operations with the tree in place and performed through the wellhead inside of the sulphur line using small diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string; i.e., small-tubing operations, shall consist of the following:

(1) For air line changes, the well shall be killed prior to beginning operations. The procedures for killing the well shall be included in the description of well-workover procedures in accordance with § 250.1622 of this part. Under these circumstances, no BOP equipment is required.

(2) For other work inside of the sulphur line, a tubing stripper or annular preventer shall be installed prior to beginning work.

(e) An essentially full-opening, work-string safety valve 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 a safety valve in the work string.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998]

§ 250.1625 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) Ram-type BOP's and the choke manifold shall be pressure tested with water to a rated working pressure or as otherwise approved by the District Supervisor. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Supervisor.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

(1) When installed;

(2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system 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 a stuck drill pipe or there are 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 time, date, and 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 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 bottomhole tools; and

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly, the pressure tests may be limited to the affected component.

(e) All personnel engaged in well-completion operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Supervisor. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

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

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

(2) The control station used during the test shall be identified in the operations log.

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

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Supervisor.

§ 250.1626 Tubing and wellhead equipment.

(a) No tubing string shall be placed into 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) Wellhead, tree, and related equipment shall be designed, installed, tested, used, and maintained so as to achieve and maintain pressure control.

§ 250.1627 Production requirements.

(a) The lessee shall conduct sulphur production operations in compliance with the approved Development and Production Plan requirements of §§ 250.1627 through 250.1634 of this subpart and requirements of this part, as appropriate.

(b) Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety of operations and protection of the human, marine, and coastal environments.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 63 FR 34597, June 25, 1998]

§ 250.1628 Design, installation, and operation of production systems.

(a) *General.* All production facilities shall be designed, installed, and maintained in a manner that provides for efficiency and safety of operations and protection of the environment.

(b) *Approval of design and installation features for sulphur production facilities.* Prior to installation, the lessee shall submit a sulphur production system application, in duplicate, to the District Supervisor for approval. The application shall include information relative to the proposed 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 at another location conveniently available to the District Supervisor. All approvals are subject to field verification. The application shall include the following:

(1) A schematic flow diagram showing size, capacity, design, working pressure of separators, storage tanks, compressor pumps, metering devices, and other sulphur-handling vessels;

(2) A schematic piping diagram showing the size and maximum allowable working pressures as determined in accordance with API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems;

(3) Electrical system information including a plan of each platform deck, outlining all hazardous areas classified according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, and outlining areas in which potential ignition sources are to be installed;

(4) 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 the new installations conform to the approved designs of this subpart.

(c) *Hydrocarbon handling vessels associated with fuel gas system.* Hydrocarbon handling vessels associated with the fuel gas system 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 Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms (API RP 14C). 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.

(d) *Approval of safety-systems design and installation features for fuel gas system.* Prior to installation, the lessee shall submit a fuel gas safety system application, in duplicate, to the District Supervisor for approval. The application shall include information relative to the proposed 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 at another location conveniently available to the District Supervisor. All approvals are subject to field verification. The application shall include the following:

(1) A schematic flow diagram showing size, capacity, design, working pressure of separators, storage tanks, compressor 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 lnstallation 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 according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Divisions 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2, and outlining areas in which potential ignition sources are to be installed;

(ii) All significant hydrocarbon sources and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and

(iii) Elementary electrical schematic of any platform safety shutdown system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed was approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the new installations conform to the approved designs of this subpart; and

(6) Design and schematics of the installation and maintenance of all fire- and gas-detection systems including the following:

(i) Type, location, and number of detection heads;

(ii) Type and kind of alarm, 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.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60026, Nov. 26, 1996. Redesignated at 63 FR 29479, May 29, 1998, as amended at 65 FR 219, Jan. 4, 2000]

§250.1629 Additional production and fuel gas system requirements.

(a) *General.* Lessees shall comply with the following production safety system requirements (some of which are in addition to those contained in §250.1628 of this part).

(b) *Design, installation, and operation of additional production systems, including fuel gas handling safety systems.* (1) Pressure and fired vessels shall be designed, fabricated, code stamped, and maintained in accordance with applicable provisions of section I, IV, and VIII of the American Society of Mechanical

Engineers (ASME) Boiler and Pressure Vessel Code.

(i) Pressure safety relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code. The safety relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the safety relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All safety relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) The lessee shall use pressure recorders to establish the operating pressure ranges of pressure vessels in order to establish the pressure-sensor settings. Pressure-recording charts used to determine operating pressure ranges shall be maintained by the lessee 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 high-pressure 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 (15 percent or 5 psi, whichever is greater) the safety relief valve's set pressure to assure that the high-pressure sensor sounds an alarm before the safety relief valve starts relieving. The low-pressure sensor shall sound an alarm no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range.

(2) *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.

(3) *Firefighting systems.* Firefighting systems shall conform to subsection 5.2, Fire Water Systems, of API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms, and shall be subject to the approval of the District Supervisor. Additional requirements shall apply as follows:

(i) A firewater system consisting of rigid pipe with firehose stations shall be installed. The firewater system shall be installed to provide needed protection, especially in areas where fuel handling equipment is located.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during platform shut-in time. 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; and

(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.

(4) *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 that is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit. 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 500, or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505.

(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 that 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, Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms.

(c) *General platform operations.* 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 safety device that is temporarily out of service shall be flagged by the person taking such device out of service.

[53 FR 10690, Apr. 1, 1988, as amended at 61 FR 60026, Nov. 26, 1996. Redesignated at 63 FR 29479, May 29, 1998, as amended at 64 FR 72794, Dec. 28, 1999; 65 FR 219, Jan. 4, 2000]

§250.1630 Safety-system testing and records.

(a) *Inspection and testing.* 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 or for safety-system devices other than those listed in API RP 14C, Appendix D the analysis technique and documentation specified therein shall be utilized for inspection and testing of these components, and the following:

(1) Safety relief valves on the natural gas feed system for power plant operations such as pressure safety valves shall be inspected and 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.

(2) The following safety devices shall be inspected and tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests:

(i) All pressure safety high or pressure safety low, and

(ii) All level safety high and level safety low controls.

(3) All pumps for firewater systems shall be inspected and operated weekly.

(4) All fire- (flame, heat, or smoke) and gas-detection systems shall be inspected and tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner.

(5) 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 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 safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or another location conveniently available to the District Supervisor. These records shall be available for MMS review. The records shall show the present status and history of each safety device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

§250.1631 Safety device training.

Prior to engaging in production operations on a lease and periodically thereafter, personnel installing, inspecting, testing, and maintaining safety devices shall be instructed in the safety requirements of the operations to be performed; possible hazards to be encountered; and general safety considerations to be taken to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available for MMS review.

§ 250.1632 Production rates.

Each sulphur deposit shall be produced at rates that will provide economic development and depletion of the deposit in a manner that would maximize the ultimate recovery of sulphur without resulting in waste (e.g., an undue reduction in the recovery of oil and gas from an associated hydrocarbon accumulation).

§ 250.1633 Production measurement.

(a) *General.* Measurement equipment and security procedures shall be designed, installed, used, maintained, and tested so as to accurately and completely measure the sulphur produced on a lease for purposes of royalty determination.

(b) *Application and approval.* The lessee shall not commence production of sulphur until the Regional Supervisor has approved the method of measurement. The request for approval of the method of measurement shall contain sufficient information to demonstrate to the satisfaction of the Regional Supervisor that the method of measurement meets the requirements of paragraph (a) of this section.

§ 250.1634 Site security.

(a) All locations where sulphur is produced, measured, or stored shall be operated and maintained to ensure against the loss or theft of produced sulphur and to assure accurate and complete measurement of produced sulphur for royalty purposes.

(b) Evidence of mishandling of produced sulphur from an offshore lease, or tampering or falsifying any measurement of production for an offshore lease, shall be reported to the Regional Supervisor as soon as possible but no later than the next business day after discovery of the evidence of mishandling.

PART 251—GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

AUTHORITY: 43 U.S.C. 1331 *et seq.*

SOURCE: 62 FR 67284, Dec. 24, 1997, unless otherwise noted.

§ 251.1 Definitions.

Terms used in this part have the following meaning:

Act means the Outer Continental Shelf Lands Act (OCSLA), as amended (43 U.S.C. 1331 *et seq.*).

Analyzed geological information means data collected under a permit or a lease that have been analyzed. Analysis may include, but is not limited to, identification of lithologic and fossil content, core analyses, laboratory analyses of physical and chemical properties, well logs or charts, results from formation fluid tests, and descriptions of hydrocarbon occurrences or hazardous conditions.

Archaeological interest means capable of providing scientific or humanistic understanding of past human behavior, cultural adaptation, and related topics