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

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Editorial Note: Nomenclature changes to part 250 appear at 71 FR 46399 and 46400, Aug. 14, 2006.

Subpart A—General

SOURCE: 64 FR 72775, Dec. 28, 1999, unless otherwise noted.

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 30 CFR 250 subpart or
(1) Applications for permit to drill	D.
(2) Development and Production Plans (DPP)	B.
(3) Downhole commingling	K.
(4) Exploration Plans (EP)	B.
(5) Flaring	K.
(6) Gas measurement	L.
(7) Off-lease geological and geophysical permits.	30 CFR 251.
(8) Oil spill financial responsibility coverage	30 CFR 253.
(9) Oil and gas production safety systems	H.
(10) Oil spill response plans	30 CFR 254.
(11) Oil and gas well-completion operations	E.
(12) Oil and gas well-workover operations	F.
(13) Decommissioning Activities	Q.
(14) Platforms and structures	I.
(15) Pipelines and Pipeline Rights-of-Way	J.
(16) Sulphur operations	P.
(17) Training	O.
(18) Unitization	M.

[64 FR 72775, Dec. 28, 1999, as amended at 67 FR 35405, May 17, 2002; 68 FR 8422, Feb. 20, 2003; 70 FR 51500, Aug. 30, 2005; 72 FR 25198, May 4, 2007]

§ 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.

Ancillary activities means those activities on your lease or unit that you:

(1) Conduct to obtain data and information to ensure proper exploration or development of your lease or unit; and

(2) Can conduct without MMS approval of an application or permit.

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.

Development geological and geophysical (G&G) activities means those G&G and related data-gathering activities on your lease or unit that you conduct following discovery of oil, gas, or sulphur in paying quantities to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

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 Manager 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, all installations permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). They include 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. They include all floating production systems (FPSs), variously described as column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. They also include 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 all installations or devices permanently or temporarily attached to the seabed. They include 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. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. 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 § 250.490(b), means a vessel, a structure, or an artificial island used for drilling, well completion, well-workover, or production operations.

(4) As used in §§ 250.900 through 250.921, means all installations or devices permanently or temporarily attached to the seabed. 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. They include all floating production systems (FPSs), including column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. 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.

Flaring means the burning of natural gas as it is released into the atmosphere.

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.

Geological and geophysical (G&G) explorations means those G&G surveys on your lease or unit that use seismic reflection, seismic refraction, magnetic, gravity, gas sniffers, coring, or other systems to detect or imply the presence of oil, gas, or sulphur in commercial quantities.

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 a natural person, an association (including partnerships, joint ventures, 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.

Prospect means a geologic feature having the potential for mineral deposits.

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 the production rate will affect ultimate recovery.

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)).

Venting means the release of gas into the atmosphere without igniting it. This includes gas that is released underwater and bubbles to the atmosphere.

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 operator or agent of the lessee(s), a pipeline right-of-way holder, or a State lessee granted a right-of-use and easement.

[64 FR 72775, Dec. 28, 1999, as amended at 68 FR 8422, Feb. 20, 2003; 70 FR 41573, July 19, 2005; 70 FR 51500, Aug. 30, 2005; 71 FR 23862, Apr. 25, 2006; 75 FR 20288, Apr. 19, 2010]

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 and work areas 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.

[64 FR 72775, Dec. 28, 1999, as amended at 73 FR 20171, Apr. 15, 2008]

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

(a) All cranes installed on fixed platforms must be operated in accordance with American Petroleum Institute's Recommended Practice for Operation and Maintenance of Offshore Cranes (API RP 2D), incorporated by reference as specified in 30 CFR 250.198.

(b) All cranes installed on fixed platforms must be equipped with a functional anti-two block device.

(c) If a fixed platform is installed after March 17, 2003, all cranes on the platform must meet the requirements of American Petroleum Institute Specification for Offshore Pedestal Mounted Cranes (API Spec 2C), incorporated by reference as specified in 30 CFR 250.198.

(d) All cranes manufactured after March 17, 2003, and installed on a fixed platform, must meet the requirements of API Spec 2C, incorporated by reference as specified in 30 CFR 250.198.

(e) You must maintain records specific to a crane or the operation of a crane installed on an OCS fixed platform, as follows:

(1) Retain all design and construction records, including installation records for any anti-two block safety devices, for the life of the crane. The records must be kept at the OCS fixed platform.

(2) Retain all inspection, testing, and maintenance records of cranes for at least 4 years. The records must be kept at the OCS fixed platform.

(3) Retain the qualification records of the crane operator and all rigger personnel for at least 4 years. The records must be kept at the OCS fixed platform.

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

[68 FR 7426, Feb. 14, 2003, as amended at 72 FR 12092, Mar. 15, 2007; 74 FR 46907, Sept. 14, 2009]

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

(a) You must submit a Welding Plan to the District Manager before you begin drilling or production activities on a lease. You may not begin welding until the District Manager 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 Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1, and Division 2 Locations (incorporated by reference as specified in § 250.198), or API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1, and Zone 2 Locations (incorporated by reference as specified in § 250.198).

(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; 68 FR 43298, July 22, 2003]

§ 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 Manager to witness each test that you conduct under this section; or

(2) Receive the District Manager'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.

FEES

§ 250.125 Service fees.

(a) The table in this paragraph (a) shows the fees that you must pay to MMS for the services listed. The fees will be adjusted periodically according to the Implicit Price Deflator for Gross Domestic Product by publication of a document in the FEDERAL REGISTER. If a significant adjustment is needed to arrive at the new actual cost for any reason other than inflation, then a proposed rule containing the new fees will be published in the FEDERAL REGISTER for comment.

SERVICE FEE TABLE

Service—processing of the following:	Fee amount	30 CFR citation
(1) Change in Designation of Operator	$164	§ 250.143(d).
(2) Right-of-Use and Easement for State lessee	$2,569	§ 250.165.
(3) Suspension of Operations/Suspension of Production (SOO/SOP) Request.	$1,968	§ 250.171(e).
(4) Exploration Plan (EP)	$3,442 for each surface location; no fee for revisions.	§ 250.211(d).
(5) Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD).	$3,971 for each well proposed; no fee for revisions.	§ 250.241(e).
(6) Deepwater Operations Plan	$3,336	§ 250.292(p).
(7) Conservation Information Document	$25,629	§ 250.296(a).
(8) Application for Permit to Drill (APD; Form MMS–123).	$1,959 for initial applications only; no fee for revisions.	§ 250.410(d); § 250.411; § 250.460; § 250.513(b); § 250.515; § 250.1605; § 250.1617(a); § 250.1622.
(9) Application for Permit to Modify (APM; Form MMS–124).	$116	§ 250.460; § 250.465(b); § 250.513(b); § 250.515; § 250.613(b); § 250.615; § 250.1618(a); § 250.1622; § 250.1704(g).
(10) New Facility Production Safety System Application for facility with more than 125 components.	$5,030 A component is a piece of equipment or ancillary system that is protected by one or more of the safety devices required by API RP 14C (incorporated by reference as specified in § 250.198); $13,238 additional fee will be charged if MMS deems it necessary to visit a facility offshore, and $6,884 to visit a facility in a shipyard.	§ 250.802(e).
(11) New Facility Production Safety System Application for facility with 25–125 components.	$1,218 Additional fee of $8,313 will be charged if MMS deems it necessary to visit a facility offshore, and $4,766 to visit a facility in a shipyard.	§ 250.802(e).
(12) New Facility Production Safety System Application for facility with fewer than 25 components.	$604	§ 250.802(e).
(13) Production Safety System Application—Modification with more than 125 components reviewed.	$561	§ 250.802(e).
(14) Production Safety System Application—Modification with 25–125 components reviewed.	$201	§ 250.802(e).
(15) Production Safety System Application—Modification with fewer than 25 components reviewed.	$85	§ 250.802(e).
(16) Platform Application—Installation—Under the Platform Verification Program.	$21,075	§ 250.905(k).
(17) Platform Application—Installation—Fixed Structure Under the Platform Approval Program.	$3,018	§ 250.905(k).
(18) Platform Application—Installation—Caisson/Well Protector.	$1,536	§ 250.905(k).
(19) Platform Application—Modification/Repair	$3,601	§ 250.905(k).
(20) New Pipeline Application (Lease Term)	$3,283	§ 250.1000(b).
(21) Pipeline Application—Modification (Lease Term).	$1,906	§ 250.1000(b).
(22) Pipeline Application—Modification (ROW)	$3,865	§ 250.1000(b).
(23) Pipeline Repair Notification	$360	§ 250.1008(e).
(24) Pipeline Right-of-Way (ROW) Grant Application.	$2,569	§ 250.1015(a).
(25) Pipeline Conversion of Lease Term to ROW	$219	§ 250.1015(a).
(26) Pipeline ROW Assignment	$186	§ 250.1018(b).
(27) 500 Feet From Lease/Unit Line Production Request.	$3,608	§ 250.1156(a).
(28) Gas Cap Production Request	$4,592	§ 250.1157.
(29) Downhole Commingling Request	$5,357	§ 250.1158(a).
(30) Complex Surface Commingling and Measurement Application.	$3,760	§ 250.1202(a); § 250.1203(b); § 250.1204(a).

SERVICE FEE TABLE—Continued

Service—processing of the following:	Fee amount	30 CFR citation
(31) Simple Surface Commingling and Measurement Application.	$1,271	§ 250.1202(a); § 250.1203(b); § 250.1204(a).
(32) Voluntary Unitization Proposal or Unit Expansion.	$11,698	§ 250.1303(d).
(33) Unitization Revision	$831	§ 250.1303(d).
(34) Application to Remove a Platform or Other Facility.	$4,342	§ 250.1727.
(35) Application to Decommission a Pipeline (Lease Term).	$1,059	§ 250.1751(a) or § 250.1752(a).
(36) Application to Decommission a Pipeline (ROW).	$2,012	§ 250.1751(a) or § 250.1752(a).

(b) Payment of the fees listed in paragraph (a) of this section must accompany the submission of the document for approval or be sent to an office identified by the Regional Director. Once a fee is paid, it is nonrefundable, even if an application or other request is withdrawn. If your application is returned to you as incomplete, you are not required to submit a new fee when you submit the amended application.

(c) Verbal approvals are occasionally given in special circumstances. Any action that will be considered a verbal permit approval requires either a paper permit application to follow the verbal approval or an electronic application submittal within 72 hours. Payment must be made with the completed paper or electronic application.

[70 FR 49875, Aug. 25, 2005, as amended at 71 FR 40909, July 19, 2006; 72 FR 25199, May 4, 2007; 73 FR 49946, Aug. 25, 2008; 75 FR 20288, Apr. 19, 2010]

§ 250.126 Electronic payment instructions.

You must file all payments electronically through *Pay.gov*. This includes, but is not limited to, all OCS applications or filing fee payments. The *Pay.gov* Web site may be accessed through a link on the MMS Offshore Web site at: *http://www.mms.gov/offshore/* homepage or directly through *Pay.gov* at: *https://www.pay.gov/paygov/*.

(a) If you submitted an application through eWell, you must use the interactive payment feature in that system, which directs you through *Pay.gov*.

(b) For applications not submitted electronically through eWell, you must use credit card or automated clearing house (ACH) payments through the *Pay.gov* Web site, and you must include a copy of the *Pay.gov* confirmation receipt page with your application.

[73 FR 49947, Aug. 25, 2008]

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 Manager's 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 Manager 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 (Form MMS–1123) 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.

(d) If you change the designated operator on your lease, you must pay the service fee listed in § 250.125 of this subpart with your request for a change in designation of operator. Should there be multiple lessees, all designation of operator forms must be collected by one lessee and submitted to MMS in a single submittal, which is subject to only one filing fee.

[64 FR 72775, Dec. 28, 1999, as amended at 70 FR 49876, Aug. 25, 2005; 72 FR 25200, May 4, 2007]

§ 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.

(f) You must pay a rental amount as required by paragraph (g) of this section if:

(1) You obtain a right-of-use and easement after January 12, 2004; or

(2) You ask MMS to modify your right-of-use and easement to change the footprint of the associated platform, artificial island, or installation or device.

(g) If you meet either of the conditions in paragraph (f) of this section, you must pay a rental amount to MMS as shown in the following table:

If...	Then...
(1) Your right-of-use and easement site is located in water depths of less than 200 meters;	You must pay a rental of $5 per acre per year with a minimum of $450 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other equipment associated with the platform, artificial island, installation or device.
(2) Your right-of-use and easement site is located in water depths of 200 meters or greater;	You must pay a rental of $7.50 per acre per year with a minimum of $675 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other equipment associated with the platform, artificial island, or installation or device.

(h) You may make the rental payments required by paragraph (g)(1) and (g)(2) of this section on an annual basis, for a 5-year period, or for multiples of 5 years. You must make the first payment electronically through *Pay.gov* and you must include a copy of the *Pay.gov* confirmation receipt page with your right-of-use and easement application. You must make all subsequent payments before the respective time periods begin.

(i) *Late payments.* An interest charge will be assessed on unpaid and underpaid amounts from the date the amounts are due, in accordance with the provisions found in 30 CFR 218.54. If you fail to make a payment that is late after written notice from MMS, MMS may initiate cancellation of the right-of-use grant and easement.

[64 FR 72775, Dec. 28, 1999, as amended at 68 FR 69311, Dec. 12, 2003; 69 FR 29433, May 24, 2004; 72 FR 25200, May 4, 2007; 73 FR 49948, Aug. 25, 2008]

§ 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 § 250.125; and

(b) The first year's rental as specified in § 250.160(g).

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 72 FR 25200, May 4, 2007]

§ 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 30 CFR 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), (d), and (e)). 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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 72 FR 25200, May 4, 2007]

§ 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). Your request must include:

(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);

(d) A commitment to production (SOP only); and

(e) The service fee listed in § 250.125 of this subpart.

[70 FR 49876, Aug. 25, 2005]

§ 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?

(a) 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.

(b) The Regional Supervisor may grant an SOO when all of the following conditions are met:

(1) The lease was issued with a primary lease term of 5 years, or with a primary term of 8 years with a requirement to drill within 5 years;

(2) Before the end of the third year of the primary term, you or your predecessor in interest must have acquired and interpreted geophysical information that indicates:

(i) The presence of a salt sheet;

(ii) That all or a portion of a potential hydrocarbon-bearing formation may lie beneath or adjacent to the salt sheet; and

(iii) The salt sheet interferes with identification of the potential hydrocarbon-bearing formation.

(3) The interpreted geophysical information required under paragraph (b)(2) of this section must include full 3-D depth migration beneath the salt sheet and over the entire lease area.

(4) Before requesting the suspension, you have conducted or are conducting additional data processing or interpretation of the geophysical information with the objective of identifying a potential hydrocarbon-bearing formation.

(5) You demonstrate that additional time is necessary to:

(i) complete current processing or interpretation of existing geophysical data or information;

(ii) acquire, process, or interpret new geophysical data or information; or

(iii) drill into the potential hydrocarbon-bearing formation identified as a result of the activities conducted in paragraphs (b)(2), (b)(4), and (b)(5) of this section.

(c) The Regional Supervisor may grant an SOO to conduct additional geological and geophysical data analysis that may lead to the drilling of a well below 25,000 feet true vertical depth below the datum at mean sea level (TVD SS) when all of the following conditions are met:

(1) The lease was issued with a primary lease term of:

(i) 5 years; or

(ii) 8 years with a requirement to drill within 5 years.

(2) Before the end of the fifth year of the primary term, you or your predecessor in interest must have acquired and interpreted geophysical information that:

(i) Indicates that all or a portion of a potential hydrocarbon-bearing formation lies below 25,000 feet TVD SS; and

(ii) Includes full 3–D depth migration over the entire lease area.

(3) Before requesting the suspension, you have conducted or are conducting additional data processing or interpretation of the geophysical information with the objective of identifying a potential hydrocarbon-bearing geologic structure or stratigraphic trap lying below 25,000 feet TVD SS.

(4) You demonstrate that additional time is necessary to:

(i) Complete current processing or interpretation of existing geophysical data or information;

(ii) Acquire, process, or interpret new geophysical or geological data or information that would affect the decision to drill the same geologic structure or stratigraphic trap, as determined by the Regional Supervisor, identified in paragraphs (c)(2) and (c)(3) of this section; or

(iii) Drill a well below 25,000 feet TVD SS into the geologic structure or stratigraphic trap identified as a result of the activities conducted in paragraphs (c)(2), (c)(3), and (c)(4)(i) and (ii) of this section.

[64 FR 72775, Dec. 28, 1999, as amended at 67 FR 44360, July 2, 2002; 70 FR 74663, Dec. 16, 2005; 72 FR 25200, May 4, 2007]

§ 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 Manager 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 Manager 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 Manager 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 Manager 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

§ 250.186 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 District Manager or Regional Supervisor.

(2) Instead of paper copies of forms available from the District Manager or Regional 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 § 250.197 or otherwise exempt from public disclosure under law or regulation.

[64 FR 72775, Dec. 28, 1999. Redesignated at 71 FR 19644, Apr. 17, 2006, as amended at 72 FR 25200, May 4, 2007]

§ 250.187 What are MMS' incident reporting requirements?

(a) You must report all incidents listed in § 250.188(a) and (b) to the District Manager. The specific reporting requirements for these incidents are contained in §§ 250.189 and 250.190.

(b) These reporting requirements apply to incidents that occur on the area covered by your lease, right-of-use and easement, pipeline right-of-way, or other permit issued by MMS, and that are related to operations resulting from the exercise of your rights under your lease, right-of-use and easement, pipeline right-of-way, or permit.

(c) Nothing in this subpart relieves you from making notifications and reports of incidents that may be required by other regulatory agencies.

(d) You must report all spills of oil or other liquid pollutants in accordance with 30 CFR 254.46.

[71 FR 19644, Apr. 17, 2006]

§ 250.188 What incidents must I report to MMS and when must I report them?

(a) You must report the following incidents to the District Manager immediately via oral communication, and provide a written follow-up report (hard copy or electronically transmitted) within 15 calendar days after the incident:

(1) All fatalities.

(2) All injuries that require the evacuation of the injured person(s) from the facility to shore or to another offshore facility.

(3) All losses of well control. ''Loss of well control'' means:

(i) Uncontrolled flow of formation or other fluids. The flow may be to an exposed formation (an underground blowout) or at the surface (a surface blowout);

(ii) Flow through a diverter; or

(iii) Uncontrolled flow resulting from a failure of surface equipment or procedures.

(4) All fires and explosions.

(5) All reportable releases of hydrogen sulfide (H_2S) gas, as defined in § 250.490(l).

(6) All collisions that result in property or equipment damage greater than $25,000. ''Collision'' means the act of a moving vessel (including an aircraft) striking another vessel, or striking a stationary vessel or object (e.g., a boat striking a drilling rig or platform). ''Property or equipment damage'' means the cost of labor and material to restore all affected items to their condition before the damage, including, but not limited to, the OCS facility, a vessel, helicopter, or equipment. It does not include the cost of salvage, cleaning, gas-freeing, dry docking, or demurrage.

(7) All incidents involving structural damage to an OCS facility. ''Structural damage'' means damage severe enough so that operations on the facility cannot continue until repairs are made.

(8) All incidents involving crane or personnel/material handling operations.

(9) All incidents that damage or disable safety systems or equipment (including firefighting systems).

(b) You must provide a written report of the following incidents to the District Manager within 15 calendar days after the incident:

(1) Any injuries that result in one or more days away from work or one or more days on restricted work or job transfer. One or more days means the injured person was not able to return to work or to all of their normal duties the day after the injury occurred;

(2) All gas releases that initiate equipment or process shutdown;

(3) All incidents that require operations personnel on the facility to muster for evacuation for reasons not related to weather or drills;

(4) All other incidents, not listed in paragraph (a) of this section, resulting

in property or equipment damage greater than $25,000.

[71 FR 19644, Apr. 17, 2006]

§ 250.189 Reporting requirements for incidents requiring immediate notification.

For an incident requiring immediate notification under § 250.188(a), you must notify the District Manager via oral communication immediately after aiding the injured and stabilizing the situation. Your oral communication must provide the following information:

(a) Date and time of occurrence;

(b) Operator, and operator representative's, name and telephone number;

(c) Contractor, and contractor representative's name and telephone number (if a contractor is involved in the incident or injury/fatality);

(d) Lease number, OCS area, and block;

(e) Platform/facility name and number, or pipeline segment number;

(f) Type of incident or injury/fatality;

(g) Operation or activity at time of incident (*i.e.*, drilling, production, workover, completion, pipeline, crane, etc.); and

(h) Description of the incident, damage, or injury/fatality.

[71 FR 19644, Apr. 17, 2006]

§ 250.190 Reporting requirements for incidents requiring written notification.

(a) For any incident covered under § 250.188, you must submit a written report within 15 calendar days after the incident to the District Manager. The report must contain the following information:

(1) Date and time of occurrence;

(2) Operator, and operator representative's name and telephone number;

(3) Contractor, and contractor representative's name and telephone number (if a contractor is involved in the incident or injury);

(4) Lease number, OCS area, and block;

(5) Platform/facility name and number, or pipeline segment number;

(6) Type of incident or injury;

(7) Operation or activity at time of incident (*i.e.*, drilling, production, workover, completion, pipeline, crane etc.);

(8) Description of incident, damage, or injury (including days away from work, restricted work or job transfer), and any corrective action taken; and

(9) Property or equipment damage estimate (in U.S. dollars).

(b) You may submit a report or form prepared for another agency in lieu of the written report required by paragraph (a) of this section, provided the report or form contains all required information.

(c) The District Manager may require you to submit additional information about an incident on a case-by-case basis.

[71 FR 19644, Apr. 17, 2006]

§ 250.191 How does MMS conduct incident investigations?

Any investigation that MMS 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 adverse parties. The purpose of the investigation is to prepare a public report that determines the cause or causes of the incident. The investigation may involve panel meetings conducted by a chairperson appointed by MMS. The following requirements apply to any panel meetings involving persons giving testimony:

(a) A person giving testimony may have legal 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.

(b) Only panel members, and any experts the panel deems necessary, may address questions to any person giving testimony.

(c) The chairperson may issue subpoenas to persons to appear and provide testimony 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.

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

[71 FR 19645, Apr. 17, 2006]

§ 250.192 What reports and statistics must I submit relating to a hurricane, earthquake, or other natural occurrence?

(a) You must submit evacuation statistics to the Regional Supervisor for a natural occurrence, such as a hurricane, a tropical storm, or an earthquake. Statistics include facilities and rigs evacuated and the amount of production shut-in for gas and oil. You must:

(1) Submit the statistics by fax or e-mail (for activities in the MMS GOM OCS Region, use Form MMS–132) as soon as possible when evacuation occurs. In lieu of submitting your statistics by fax or e-mail, you may submit them electronically in accordance with 30 CFR 250.186(a)(3);

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

(3) Inform MMS when you resume production; and

(4) Submit the statistics either by MMS district, or the total figures for your operations in an MMS region.

(b) If your facility, production equipment, or pipeline is damaged by a natural occurrence, you must:

(1) Submit an initial damage report to the Regional Supervisor within 48 hours after you complete your initial evaluation of the damage. You must use Form MMS–143, Facility/Equipment Damage Report, to make this and all subsequent reports. In lieu of submitting Form MMS–143 by fax or e-mail, you may submit the damage report electronically in accordance with 30 CFR 250.186(a)(3). In the report, you must:

(i) Name the items damaged (e.g., platform or other structure, production equipment, pipeline);

(ii) Describe the damage and assess the extent of the damage (major, medium, minor); and

(iii) Estimate the time it will take to replace or repair each damaged structure and piece of equipment and return it to service. The initial estimate need not be provided on the form until availability of hardware and repair capability has been established (not to exceed 30 days from your initial report).

(2) Submit subsequent reports monthly and immediately whenever information submitted in previous reports changes until the damaged structure or equipment is returned to service. In the final report, you must provide the date the item was returned to service.

[73 FR 64545, Oct. 30, 2008]

§ 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 How must I protect archaeological resources?

(a) If the Regional Director has reason to believe that an archaeological resource may exist in the lease area, the Regional Director will require in writing that your EP, DOCD, or DPP be accompanied by an archaeological report. 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 or right-of-way 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.

[64 FR 72775, Dec. 28, 1999, as amended at 71 FR 23862, Apr. 25, 2006; 72 FR 25200, May 4, 2007]

§ 250.195 What notification does MMS require on the production status of wells?

You must notify the appropriate MMS District Manager when you successfully complete or recomplete a well for production. You must:

(a) Notify the District Manager within 5 working days of placing the well in a production status. You must confirm oral notification by telefax or e-mail within those 5 working days.

(b) Provide the following information in your notification:

(1) Lessee or operator name;

(2) Well number, lease number, and OCS area and block designations;

(3) Date you placed the well on production (indicate whether or not this is first production on the lease);

(4) Type of production; and

(5) Measured depth of the production interval.

[71 FR 23862, Apr. 25, 2006]

§ 250.196 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.

[64 FR 72775, Dec. 28, 1999. Redesignated at 71 FR 23862, Apr. 25, 2006]

§ 250.197 Data and information to be made available to the public or for limited inspection.

MMS will protect data and information that you submit under this part, and part 203 of this chapter, as described in this section. 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, under what circumstances, and in what time period. Paragraph (c) of this section describes what data and information will be made available for limited inspection without the consent of the lessee, and under what circumstances.

(a) All data and information you submit on MMS forms will be made available to the public upon submission, except as specified in the following table:

On form . . .	Data and information not immediately available are . . .	Excepted data will be made available . . .
(1) MMS–123, Application for Permit to Drill.	Items 15, 16, 22 through 25 ...	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(2) MMS–123S, Supplemental APD Information Sheet.	Items 3, 7, 8, 15 and 17	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(3) MMS–124, Application for Permit to Modify.	Item 17	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(4) MMS–125, End of Operations Report.	Items 12, 13, 17, 21, 22, 26 through 38.	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier. However, items 33 through 38 will not be released when the well goes on production unless the period of time in the table in paragraph (b) has expired.
(5) MMS–126, Well Potential Test Report.	Item 101	2 years after you submit it.
(6) MMS–127, Sensitive Reservoir Information Report.	Items 124 through 168	2 years after the effective date of the Sensitive Reservoir Information Report.
(7) MMS–133 Well Activity Report.	Item 10 Fields [WELLBORE START DATE, TD DATE, OP STATUS, END DATE, MD, TVD, AND MW PPG]. Item 11 Fields [WELLBORE START DATE, TD DATE, PLUGBACK DATE, FINAL MD, AND FINAL TVD] and Items 12 through 15.	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(8) MMS–133S Open Hole Data Report.	Boxes 7 and 8	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(9) MMS–137 OCS Plan Information.	Items providing the bottomhole location, true vertical depth, and measured depth of wells.	When the well goes on production or according to the table in paragraph (b) of this section, whichever is earlier.
(10) MMS–140, Bottomhole Pressure Survey Report.	All items	2 years after the date of the survey.

(b) MMS will release lease and permit data and information that you submit and MMS retains, but that are not normally 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 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.
(2) 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.
(3) 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.

If	MMS will release	At this time	Special provisions
(4) 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.
(5) 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.
(6) 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.
(7) Data or information is submitted on well operations.	Descriptions of downhole locations, operations, and equipment.	When the well goes on production or when geological data is released according to §§ 250.197(b)(5) and (b)(6), whichever occurs earlier.	Directional survey data may be released earlier to the owner of an adjacent lease according to Subpart D of this part.
(8) Data and information are obtained from beneath unleased land as a result of a well deviation that has not been approved by the District Manager or Regional Supervisor.	Any data or information obtained.	At any time	None.
(9) Except for high-resolution data and information released under paragraph (b)(2) of this section data and information acquired by a permit under part 251 are submitted by a lessee under 30 CFR part 203 or part 250.	G&G data, analyzed geological information, processed and interpreted G&G information.	Geological data and information: 10 years after MMS issues the permit; Geophysical data: 50 years after MMS issues the permit; Geophysical information: 25 years after MMS issues the permit.	None.

(c) MMS may allow limited inspection, but only by persons with a direct interest in related MMS decisions and issues in specific geographic areas, and who agree in writing to its confidentiality, of G&G data and information submitted under this part or part 203 of this chapter that MMS uses to:

(1) Make unitization determinations on two or more leases;

(2) Make competitive reservoir determinations;

(3) Ensure proper plans of development for competitive reservoirs;

(4) Promote operational safety;

(5) Protect the environment;

(6) Make field determinations; or

(7) Determine eligibility for royalty relief.

[64 FR 72775, Dec. 28, 1999, as amended at 71 FR 16039, Mar. 30, 2006. Redesignated and amended at 71 FR 23862, Apr. 25, 2006; 72 FR 25200, May 4, 2007]

REFERENCES

§ 250.198 Documents incorporated by reference.

(a) The MMS is incorporating by reference the documents listed in paragraphs (e) through (k) of this section. Paragraphs (e) through (k) identify the publishing organization of the documents, the address and phone number where you may obtain these documents, and the documents incorporated by reference. The Director of the Federal Register has approved the incorporations by reference according to 5 U.S.C. 552(a) and 1 CFR part 51.

(1) Incorporation by reference of a document is limited to the edition of the publication that is cited in this section. Future amendments or revisions of the document are not included. The MMS will publish any changes to a document in the FEDERAL REGISTER and amend this section.

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

(b) The 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 20170; phone: 703–787–1587; or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html.*

(e) American Concrete Institute (ACI), ACI Standards, P. O. Box 9094, Farmington Hill, MI 48333–9094: *http://www.concrete.org;* phone: 248–848–3700:

(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95), incorporated by reference at § 250.901(a), (d).

(2) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997, incorporated by reference at § 250.901(a), (d).

(f) American Institute of Steel Construction, Inc. (AISC), AISC Standards, One East Wacker Drive, Suite 700, Chicago, IL 60601–1802; *http://www.aisc.org;* phone: 312–670–2400:

(1) ANSI/AISC 360–05, Specification for Structural Steel Buildings incorporated by reference at § 250.901(a), (d).

(2) [Reserved]

(g) American National Standards Institute (ANSI), ANSI/ASME Codes, ATTN: Sales Department, 25 West 43rd Street, 4th Floor, New York, NY 10036; *http://www.ansi.org;* phone: 212–642–4900; and/or American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007–2900; *http://www.asme.org;* phone: 973–882–5155:

(1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at § 250.803(b)(1), (b)(1)(i); and § 250.1629(b)(1), (b)(1)(i);

(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at § 250.803(b)(1), (b)(1)(i); and § 250.1629(b)(1), (b)(1)(i);

(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1 and 2, and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at

§ 250.803(b)(1), (b)(1)(i); and § 250.1629(b)(1), (b)(1)(i);

(4) ANSI/ASME B 16.5–2003, Pipe Flanges and Flanged Fittings incorporated by reference at § 250.1002(b)(2);

(5) ANSI/ASME B 31.8–2003, Gas Transmission and Distribution Piping Systems incorporated by reference at § 250.1002(a);

(6) 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, incorporated by reference at § 250.806(a)(2)(i);

(7) ANSI Z88.2–1992, American National Standard for Respiratory Protection, incorporated by reference at, § 250.490(g)(4)(iv), (j)(13)(ii).

(h) American Petroleum Institute (API), API Recommended Practices (RP), Specs, Standards, Manual of Petroleum Measurement Standards (MPMS) chapters, 1220 L Street, NW., Washington, DC 20005–4070; *http://www.api.org;* phone: 202–682–8000:

(1) API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006, Product No. C51009; incorporated by reference at § 250.803(b)(1); and § 250.1629(b)(1);

(2) API Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, May 2007, Product No. G2DGINT; incorporated by reference at § 250.901(a), (d);

(3) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, May 2007, Product No. G2EXINT; incorporated by reference at § 250.901(a), (d);

(4) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, May 2007, Product No. G2INTMET; incorporated by reference at § 250.901(a), (d);

(5) API MPMS, Chapter 1—Vocabulary, Second Edition, July 1994, Order No. 852–01002; incorporated by reference at § 250.1201;

(6) API MPMS, Chapter 2—Tank Calibration, Section 2A—Measurement and Calibration of Upright Cylindrical Tanks by the Manual Tank Strapping Method, First Edition, February 1995; reaffirmed February 2007, Order No. 852–022A1; incorporated by reference at § 250.1202(l)(4);

(7) API MPMS, Chapter 2—Tank Calibration, Section 2B—Calibration of Upright Cylindrical Tanks Using the Optical Reference Line Method, First Edition, March 1989; reaffirmed, December 2007, Order No. H30023; incorporated by reference at § 250.1202(l)(4);

(8) API MPMS, Chapter 3—Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005, Product No. H301A02; incorporated by reference at § 250.1202(l)(4);

(9) API MPMS, Chapter 3—Tank Gauging, Section 1B—Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, Second Edition, June 2001, reaffirmed, October 2006, Product No. H301B2; incorporated by reference at § 250.1202(l)(4);

(10) API MPMS, Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005, Product No. H04013; incorporated by reference at § 250.1202(a)(3), (f)(1);

(11) API MPMS, Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003, Product No. H04023; incorporated by reference at § 250.1202(a)(3), (f)(1);

(12) API MPMS, Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, reaffirmed November 2005, Order No. H04042; incorporated by reference at § 250.1202(a)(3), (f)(1);

(13) API MPMS, Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, reaffirmed: August 2005, Order No. H04052; incorporated by reference at § 250.1202(a)(3), (f)(1);

(14) API MPMS, Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, May 1999; reaffirmed 2003, Order No. H04062; incorporated by reference at § 250.1202(a)(3), (f)(1);

(15) API MPMS, Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed 2003, Order No. H04072; incorporated by reference at § 250.1202(a)(3), (f)(1);

(16) API MPMS, Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Fourth Edition, September 2005, Product No. H05014; incorporated by reference at § 250.1202(a)(3);

(17) API MPMS, Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005, Product No. H05023; incorporated by reference at § 250.1202(a)(3);

(18) API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005, Product No. H05035; incorporated by reference at § 250.1202(a)(3);

(19) API MPMS, Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005, Product No. H05044; incorporated by reference at § 250.1202(a)(3);

(20) API MPMS, Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005, Product No. H50502; incorporated by reference at § 250.1202(a)(3);

(21) API MPMS, Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed, April 2007, Order No. H30121; incorporated by reference at § 250.1202(a)(3);

(22) API MPMS, Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed, February 2007, Order No. 852–30126; incorporated by reference at § 250.1202(a)(3);

(23) API MPMS, Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed, April 2007, Order No. 852–30127; incorporated by reference at § 250.1202(a)(3);

(24) API MPMS, Chapter 7—Temperature Determination, First Edition, June 2001; reaffirmed, March 2007; Product No. H07001; incorporated by reference at § 250.1202(a)(3), (l)(4);

(25) API MPMS, Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; reaffirmed, March 2006, Order No. H08013; incorporated by reference at § 250.1202(b)(4)(i), (l)(4);

(26) API MPMS, Chapter 8—Sampling, Section 2—Standard Practice for Automatic Sampling of Liquid Petroleum and Petroleum Products, Second Edition, October 1995; reaffirmed, June 2005, Order No. H08022; incorporated by reference at § 250.1202(a)(3), (l)(4);

(27) API MPMS, Chapter 9—Density Determination, Section 1—Standard Test Method for Density, Relative Density (Specific Gravity), or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, Second Edition, December 2002; reaffirmed October 2005, Product No. H09012; incorporated by reference at § 250.1202(a)(3), (l)(4);

(28) API MPMS, Chapter 9—Density Determination, Section 2—Standard Test Method for Density or Relative Density of Light Hydrocarbons by Pressure Hydrometer, Second Edition, March 2003, Product No. H09022; incorporated by reference at § 250.1202(a)(3), (l)(4);

(29) API MPMS, Chapter 10—Sediment and Water, Section 1—Standard Test Method for Sediment in Crude Oils and Fuel Oils by the Extraction Method, Third Edition, November 2007, Product No. H10013; incorporated by reference at § 250.1202(a)(3), (l)(4);

(30) API MPMS, Chapter 10—Sediment and Water, Section 2—Standard Test Method for Water in Crude Oil by Distillation, Second Edition, November 2007, Product No. H10022; incorporated by reference at § 250.1202(a)(3), (l)(4);

(31) API MPMS, Chapter 10—Sediment and Water, Section 3—Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method (Laboratory Procedure), Third Edition, May 2008, Product No. H10033; incorporated by reference at § 250.1202(a)(3), (l)(4);

(32) API MPMS, Chapter 10—Sediment and Water, Section 4—Determination of Water and/or Sediment in Crude Oil by the Centrifuge Method (Field Procedure), Third Edition, December 1999, Order No. H10043; incorporated by reference at § 250.1202(a)(3), (l)(4);

(33) API MPMS, Chapter 10—Sediment and Water, Section 9—Standard Test Method for Water in Crude Oils by

Coulometric Karl Fischer Titration, Second Edition, December 2002; reaffirmed 2005, Product No. H10092; incorporated by reference at § 250.1202(a)(3), (l)(4);

(34) 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 at 60 °F, API Standard 2540, First Edition, August 1980; reaffirmed March 1997, API Stock No. H27000; incorporated by reference at § 250.1202(a)(3), (g)(3), (l)(4);

(35) 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: December 2007, Order No. 852–27307; incorporated by reference at § 250.1202(a)(3), (g)(4);

(36) API MPMS, Chapter 11—Physical Properties Data, Addendum to Section 2, Part 2—Compressibility Factors for Hydrocarbons, Correlation of Vapor Pressure for Commercial Natural Gas Liquids, First Edition, December 1994; reaffirmed, December 2002, Order No. H27308; incorporated by reference at § 250.1202(a)(3);

(37) API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 1—Introduction, Second Edition, May 1995; reaffirmed March 2002, Order No. H12021; incorporated by reference at § 250.1202(a)(3), (g)(1), (g)(2);

(38) API MPMS, Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 2—Measurement Tickets, Third Edition, June 2003, Product No. H12223; incorporated by reference at § 250.1202(a)(3), (g)(1), (g)(2);

(39) 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 January 2003, Order No. 852–30350; incorporated by reference at § 250.1203(b)(2);

(40) API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters, Part 2—Specification and Installation Requirements, Fourth Edition, April 2000; reaffirmed March 2006, Order No. H14324; incorporated by reference at § 250.1203(b)(2);

(41) API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 3—Concentric, Square-Edged Orifice Meters; Part 3—Natural Gas Applications; Third Edition, August 1992; Errata March 1994, reaffirmed, February 2009, Product No. H143303; incorporated by reference at § 250.1203(b)(2);

(42) API MPMS, Chapter 14.5/GPA Standard 2172–09; Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer; Third Edition, January 2009; Adopted as Tentative Standard, 1972; Revised and Adopted as Standard, 1976; Revised 1984, 1986, 1996, 2009; Product No. H140503; incorporated by reference at § 250.1203(b)(2);

(43) API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 6—Continuous Density Measurement, Second Edition, April 1991; reaffirmed, February 2006, Order No. H30346; incorporated by reference at § 250.1203(b)(2);

(44) API MPMS, Chapter 14—Natural Gas Fluids Measurement, Section 8—Liquefied Petroleum Gas Measurement, Second Edition, July 1997; reaffirmed, March 2006, Order No. H14082; incorporated by reference at § 250.1203(b)(2);

(45) API MPMS, Chapter 20—Section 1—Allocation Measurement, First Edition, September 1993; reaffirmed October 2006, Order No. 852–30701; incorporated by reference at § 250.1202(k)(1);

(46) API MPMS, Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement, First Edition, August 1993; reaffirmed, July 2005, Order No. 852–30730; incorporated by reference at § 250.1203(b)(4);

(47) API RP 2A–WSD, Recommended Practice for Planning, Designing and

Constructing Fixed Offshore Platforms—Working Stress Design, Twenty-first Edition, December 2000; Errata and Supplement 1, December 2002; Errata and Supplement 2, September 2005; Errata and Supplement 3, October 2007; Product No. G2AWSD; incorporated by reference at § 250.901(a), (d); § 250.908(a); § 250.919(b)(2); § 250.920(a), (b), (c), (d), (e), (f);

(48) API RP 2D, Operation and Maintenance of Offshore Cranes, Sixth Edition, May 2007, Product No. G02D06; incorporated by reference at § 250.108(a);

(49) API RP 2FPS, RP for Planning, Designing, and Constructing Floating Production Systems; First Edition, March 2001, Order No. G2FPS1; incorporated by reference at § 250.901(a), (d);

(50) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Structures; Third Edition, April 2008, Product No. G02I03; incorporated by reference at § 250.901(a), (d);

(51) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009; Order No. G02RD1; incorporated by reference at § 250.800(b)(2); § 250.901(a), (d); § 250.1002(b)(5);

(52) API RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, Product No. G2SK03; incorporated by reference at § 250.800(b)(3); § 250.901(a), (d);

(53) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007, Product No. G02SM1; incorporated by reference at § 250.901(a), (d);

(54) API RP 2T, Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997, Order No. G02T02; incorporated by reference at § 250.901(a), (d);

(55) API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress, Product No. GX14B05; incorporated by reference at § 250.801(e)(4); § 250.804(a)(1)(i);

(56) API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, reaffirmed: March 2007; Product No. C14C07; incorporated by reference at § 250.125(a); § 250.292(j); § 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)(6); § 250.1002(d); § 250.1004(b)(9); § 250.1628(c), (d)(2); § 250.1629(b)(2), (b)(4)(v); § 250.1630(a);

(57) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; reaffirmed, March 2007, Order No. 811–07185; incorporated by reference at § 250.802(e)(3); § 250.1628(b)(2), (d)(3);

(58) API RP 14F, Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, Fifth Edition, July 2008, Product No. G14F05; incorporated by reference at § 250.114(c); § 250.803(b)(9)(v); § 250.1629(b)(4)(v);

(59) API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, First Edition, September 2001, reaffirmed: March 2007; Product No. G14FZ1; incorporated by reference at § 250.114(c); § 250.803(b)(9)(v); § 250.1629(b)(4)(v);

(60) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; Product No. G14G04; incorporated by reference at § 250.803(b)(8), (b)(9)(v); § 250.1629(b)(3), (b)(4)(v);

(61) API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007, Product No. G14H05; incorporated by reference at § 250.802(d); § 250.804(a)(5);

(62) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; reaffirmed: March 2007; Product No. G14J02; incorporated by reference at § 250.800(b)(1); § 250.901(a)(14);

(63) API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells, Third Edition, March 1997; reaffirmed September 2004, Order No. G53003; incorporated by reference at § 250.442(c); § 250.446(a);

(64) API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deepwater Wells, First Edition, September 2002, Product No. G56001; incorporated by reference at § 250.415(e);

(65) 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; reaffirmed November 2002, Product No. C50002; incorporated by reference at § 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3), (d)(4)(i); § 250.1629(b)(4)(i);

(66) 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; reaffirmed November 2002, Order No. C50501; incorporated by reference at § 250.114(a); § 250.459; § 250.802(e)(4)(i); § 250.803(b)(9)(i); § 250.1628(b)(3), (d)(4)(i); § 250.1629(b)(4)(i);

(67) API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003, Order No. H25560; incorporated by reference at § 250.1202(l)(4);

(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Eighth Edition, December 2007, Effective Date: June 15, 2008, Product No. GXQ108; incorporated by reference at § 250.806(a)(2)(ii);

(69) API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004, Product No. G02C06; incorporated by reference at § 250.108(c), (d);

(70) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004; Effective Date: February 1, 2005; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009; Addendum 1, February 2008; Addendum 2, 3, and 4, December 2008; Product No. GX06A19; incorporated by reference at § 250.806(a)(3); § 250.1002(b)(1), (b)(2);

(71) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003, Order No. G06AV1; incorporated by reference at § 250.806(a)(3);

(72) ANSI/API Spec. 6D, Specification for Pipeline Valves, Twenty-third Edition, April 2008; Effective Date: October 1, 2008, Errata 1, June 2008; Errata 2, November 2008; Errata 3, February 2009; Addendum 1, October 2009; Contains API Monogram Annex as Part of U.S. National Adoption; ISO 14313:2007 (Identical), Petroleum and natural gas industries—Pipeline transportation systems—Pipeline valves; Product No. GX6D23; incorporated by reference at § 250.1002(b)(1);

(73) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Effective Date: May 1, 2006; also available as ISO 10432:2004, Product No. GX14A11; incorporated by reference at § 250.806(a)(3);

(74) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008; Effective Date: January 1, 2009, Contains API Monogram

Annex as Part of U.S. National Adoption; ISO 13628–2:2006 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 2: Unbonded flexible pipe systems for subsea and marine application; Product No. GX17J03; incorporated by reference at § 250.803(b)(2)(iii); § 250.1002(b)(4); § 250.1007(a)(4);

(75) API Standard 2551, Measurement and Calibration of Horizontal Tanks, First Edition, 1965; reaffirmed March 2002, API Stock No. H25510; incorporated by reference at § 250.1202(l)(4);

(76) API Standard 2552, USA Standard Method for Measurement and Calibration of Spheres and Spheroids, First Edition, 1966; reaffirmed, October 2007 (ASTM designation: D 1408–65; date of joint API/ASTM approval, 1965); incorporated by reference at § 250.1202(l)(4);

(77) API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; Order No. 852–25550; incorporated by reference at § 250.1202(l)(4).

(78) API RP 90, Annular Casing Pressure Management for Offshore Wells, First Edition, August 2006, Product No. G09001, incorporated by reference at § 250.518.

(i) American Society for Testing and Materials (ASTM), ASTM Standards, 100 Bar Harbor Drive, P. O. Box C700, West Conshohocken, PA 19428–2959; *http://www.astm.org;* phone: 610–832–9500:

(1) ASTM Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates; incorporated by reference at § 250.901(a), (d);

(2) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete; incorporated by reference at § 250.901(a), (d);

(3) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement; incorporated by reference at § 250.901(a), (d);

(4) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete; incorporated by reference at § 250.901(a), (d);

(5) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements; incorporated by reference at § 250.901(a), (d);

(j) American Welding Society (AWS), AWS Codes, 550 NW, LeJeune Road, Miami, FL 33126; *http://www.aws.org*; phone: 800–443–9353:

(1) AWS D1.1:2000, Structural Welding Code—Steel; incorporated by reference at § 250.901(a), (d);

(2) AWS D1.4–98, Structural Welding Code—Reinforcing Steel; incorporated by reference at § 250.901(a), (d);

(3) AWS D3.6M:1999, Specification for Underwater Welding; incorporated by reference at § 250.901(a), (d).

(k) National Association of Corrosion Engineers (NACE), NACE Standards, 1440 South Creek Drive, Houston, TX 77084; *http://www.nace.org*; phone: 281–228–6200:

(1) NACE Standard MR0175–2003, Item No. 21302, Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments; incorporated by reference at § 250.901(a), § 250.490(p)(2);

(2) NACE Standard RP0176–2003, Item No. 21018, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production; incorporated by reference at § 250.901(a), (d).

[75 FR 22222, Apr. 28, 2010, as amended at 75 FR 23584, May 4, 2010]

§ 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 § 250.197, 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 5438, 1849 C Street, NW., Washington, DC 20240.

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

30 CFR subpart, title and/or MMS Form (OMB Control No.)	Reasons for collecting information and how used
(1) Subpart A, General (1010–0114), including Forms MMS–132, Evacuation Statistics; MMS–143, Facility/Equipment Damage Report; MMS–1123, Designation of Operator; MMS–1832, Notification of Incidents of Noncompliance.	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. To allow MMS to rapidly assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.
(2) Subpart B, Exploration and Development and Production Plans (1010–0151), including Forms MMS–137, OCS Plan Information Form; MMS–139, EP Air Quality Screening Checklist; MMS–138, DOCD Air Quality Screening Checklist, MMS–141, ROV Survey Report Form; MMS–142, Environmental Impact Analysis Worksheet.	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 and Drilling Operations (1010–0141), including Forms MMS–123, Application for Permit to Drill; MMS–123S, Supplemental APD Information Sheet; MMS–124, Application for Permit to Modify; MMS–125, End of Operations Report; MMS–133, Well Activity Report; MMS–133S, Open Hole Data Report.	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 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.
(8) Subpart I, Platforms and Structures (1010–0149) ..	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.
(9) 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.
(10) Subpart K, Oil and Gas Production Rates (1010–0041), including Forms MMS–126, Well Potential Test Report; MMS–127, Sensitive Reservoir Information Report; MMS–128, Semiannual Well Test Report; MMS–140 Bottomhole Pressure Survey Report.	To inform MMS of production rates for hydrocarbons produced on the OCS. To ensure economic maximization of ultimate hydrocarbon recovery.
(11) 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.
(12) 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.

30 CFR subpart, title and/or MMS Form (OMB Control No.)	Reasons for collecting information and how used
(13) Subpart N, Remedies and Penalties	The requirements in subpart N are exempt from the Paperwork Reduction Act of 1995 according to 5 CFR 1320.4.
(14) Subpart O, Well Control and Production Safety Training (1010–0128).	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.
(15) 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.
(16) Subpart Q, Decommissioning Activities (1010–0142).	To determine that decommissioning activities comply with regulatory requirements and approvals. To ensure that site clearance and platform or pipeline removal are properly performed to protect marine life and the environment and do not conflict with other users of the OCS.
(17) Form MMS–131, Performance Measures (1010–0112).	Voluntary. We use the information obtained from this form to develop an industry average that helps to describe how well the offshore oil and gas industry is performing.
(18) Form MMS–144, Rig Movement Notification Report (form used in the GOM OCS Region), Subparts D, E, F, (1010–0150).	The rig notification requirement is essential for MMS inspection scheduling and to verify that the equipment being used complies with approved permits.

[64 FR 72775, Dec. 28, 1999, as amended at 67 FR 35405, May 17, 2002; 68 FR 8422, Feb. 20, 2003; 71 FR 23863, Apr. 25, 2006; 72 FR 25200, May 4, 2007; 73 FR 64546, Oct. 30, 2008; 74 FR 46908, Sept. 14, 2009; 75 FR 20289, Apr. 19, 2010]

Subpart B—Plans and Information

SOURCE: 70 FR 51501, Aug. 30, 2005, unless otherwise noted.

GENERAL INFORMATION

§ 250.200 Definitions.

Acronyms and terms used in this subpart have the following meanings:

(a) *Acronyms* used frequently in this subpart are listed alphabetically below:

CID means Conservation Information Document

CZMA means Coastal Zone Management Act

DOCD means Development Operations Coordination Document

DPP means Development and Production Plan

DWOP means Deepwater Operations Plan

EIA means Environmental Impact Analysis

EP means Exploration Plan

MMS means Minerals Management Service

NPDES means National Pollutant Discharge Elimination System

NTL means Notice to Lessees and Operators

OCS means Outer Continental Shelf

(b) *Terms* used in this subpart are listed alphabetically below:

Amendment means a change you make to an EP, DPP, or DOCD that is pending before MMS for a decision (see §§ 250.232(d) and 250.267(d)).

Modification means a change required by the Regional Supervisor to an EP, DPP, or DOCD (see § 250.233(b)(2) and § 250.270(b)(2)) that is pending before MMS for a decision because the OCS plan is inconsistent with applicable requirements.

New or unusual technology means equipment or procedures that:

(1) Have not been used previously or extensively in an MMS OCS Region;

(2) Have not been used previously under the anticipated operating conditions; or

(3) Have operating characteristics that are outside the performance parameters established by this part.

Non-conventional production or completion technology includes, but is not limited to, floating production systems, tension leg platforms, spars, floating production, storage, and offloading systems, guyed towers, compliant towers, subsea manifolds, and other subsea production components that rely on a remote site or host facility for utility and well control services.

Offshore vehicle means a vehicle that is capable of being driven on ice.

Resubmitted OCS plan means an EP, DPP, or DOCD that contains changes you make to an OCS plan that MMS has disapproved (see §§ 250.234(b), 250.272(a), and 250.273(b)).

Revised OCS plan means an EP, DPP, or DOCD that proposes changes to an approved OCS plan, such as those in the location of a well or platform, type of drilling unit, or location of the onshore support base (see § 250.283(a)).

Supplemental OCS plan means an EP, DPP, or DOCD that proposes the addition to an approved OCS plan of an activity that requires approval of an application or permit (see § 250.283(b)).

§ 250.201 What plans and information must I submit before I conduct any activities on my lease or unit?

(a) *Plans and documents.* Before you conduct the activities on your lease or unit listed in the following table, you must submit, and MMS must approve, the listed plans and documents. Your plans and documents may cover one or more leases or units.

You must submit a(n) . . .	Before you . . .
(1) Exploration Plan (EP)	Conduct any exploration activities on a lease or unit.
(2) Development and Production Plan (DPP).	Conduct any development and production activities on a lease or unit in any OCS area other than the Western Gulf of Mexico.
(3) Development Operations Coordination Document (DOCD).	Conduct any development and production activities on a lease or unit in the Western GOM.
(4) Deepwater Operations Plan (DWOP)	Conduct post-drilling installation activities in any water depth associated with a development project that will involve the use of a non-conventional production or completion technology.
(5) Conservation Information Document (CID).	Commence production from development projects in water depths greater than 1,312 feet (400 meters).
(6) EP, DPP, or DOCD	Conduct geological or geophysical (G&G) exploration or a development G&G activity (see definitions under § 250.105) on your lease or unit when: (i) It will result in a physical penetration of the seabed greater than 500 feet (152 meters); (ii) It will involve the use of explosives; (iii) The Regional Director determines that it might have a significant adverse effect on the human, marine, or coastal environment; or (iv) The Regional Supervisor, after reviewing a notice under § 250.209, determines that an EP, DPP, or DOCD is necessary.

(b) *Submitting additional information.* On a case-by-case basis, the Regional Supervisor may require you to submit additional information if the Regional Supervisor determines that it is necessary to evaluate your proposed plan or document.

(c) *Limiting information.* The Regional Director may limit the amount of information or analyses that you otherwise must provide in your proposed plan or document under this subpart when:

(1) Sufficient applicable information or analysis is readily available to MMS;

(2) Other coastal or marine resources are not present or affected;

(3) Other factors such as technological advances affect information needs; or

(4) Information is not necessary or required for a State to determine consistency with their CZMA Plan.

(d) *Referencing.* In preparing your proposed plan or document, you may reference information and data discussed in other plans or documents you previously submitted or that are otherwise readily available to MMS.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 25200, May 4, 2007]

§ 250.202 What criteria must the Exploration Plan (EP), Development and Production Plan (DPP), or Development Operations Coordination Document (DOCD) meet?

Your EP, DPP, or DOCD must demonstrate that you have planned and are prepared to conduct the proposed activities in a manner that:

(a) Conforms to the Outer Continental Shelf Lands Act as amended (Act), applicable implementing regulations, lease provisions and stipulations, and other Federal laws;

(b) Is safe;

(c) Conforms to sound conservation practices and protects the rights of the lessor;

(d) Does not unreasonably interfere with other uses of the OCS, including those involved with national security or defense; and

(e) Does not cause undue or serious harm or damage to the human, marine, or coastal environment.

§ 250.203 Where can wells be located under an EP, DPP, or DOCD?

The Regional Supervisor reviews and approves proposed well location and spacing under an EP, DPP, or DOCD. In deciding whether to approve a proposed well location and spacing, the Regional Supervisor will consider factors including, but not limited to, the following:

(a) Protecting correlative rights;

(b) Protecting Federal royalty interests;

(c) Recovering optimum resources;

(d) Number of wells that can be economically drilled for proper reservoir management;

(e) Location of drilling units and platforms;

(f) Extent and thickness of the reservoir;

(g) Geologic and other reservoir characteristics;

(h) Minimizing environmental risk;

(i) Preventing unreasonable interference with other uses of the OCS; and

(j) Drilling of unnecessary wells.

§ 250.204 How must I protect the rights of the Federal government?

(a) To protect the rights of the Federal government, you must either:

(1) Drill and produce the wells that the Regional Supervisor determines are necessary to protect the Federal government from loss due to production on other leases or units or from adjacent lands under the jurisdiction of other entities (e.g., State and foreign governments); or

(2) Pay a sum that the Regional Supervisor determines as adequate to compensate the Federal government for your failure to drill and produce any well.

(b) Payment under paragraph (a)(2) of this section may constitute production in paying quantities for the purpose of extending the lease term.

(c) You must complete and produce any penetrated hydrocarbon-bearing zone that the Regional Supervisor determines is necessary to conform to sound conservation practices.

§ 250.205 Are there special requirements if my well affects an adjacent property?

For wells that could intersect or drain an adjacent property, the Regional Supervisor may require special measures to protect the rights of the Federal government and objecting lessees or operators of adjacent leases or units.

§ 250.206 How do I submit the EP, DPP, or DOCD?

(a) *Number of copies.* When you submit an EP, DPP, or DOCD to MMS, you must provide:

(1) Four copies that contain all required information (proprietary copies);

(2) Eight copies for public distribution (public information copies) that omit information that you assert is exempt from disclosure under the Freedom of Information Act (FOIA) (5 U.S.C. 552) and the implementing regulations (43 CFR part 2); and

(3) Any additional copies that may be necessary to facilitate review of the EP, DPP, or DOCD by certain affected States and other reviewing entities.

(b) *Electronic submission.* You may submit part or all of your EP, DPP, or DOCD and its accompanying information electronically. If you prefer to submit your EP, DPP, or DOCD electronically, ask the Regional Supervisor for further guidance.

(c) *Withdrawal after submission.* You may withdraw your proposed EP, DPP, or DOCD at any time for any reason. Notify the appropriate MMS OCS Region if you do.

Ancillary Activities

§ 250.207 What ancillary activities may I conduct?

Before or after you submit an EP, DPP, or DOCD to MMS, you may elect, the regulations in this part may require, or the Regional Supervisor may direct you to conduct ancillary activities. Ancillary activities include:

(a) Geological and geophysical (G&G) explorations and development G&G activities;

(b) Geological and high-resolution geophysical, geotechnical, archaeological, biological, physical oceanographic, meteorological, socioeconomic, or other surveys; or

(c) Studies that model potential oil and hazardous substance spills, drilling muds and cuttings discharges, projected air emissions, or potential hydrogen sulfide (H_2S) releases.

§ 250.208 If I conduct ancillary activities, what notices must I provide?

At least 30 calendar days before you conduct any G&G exploration or development G&G activity (see § 250.207(a)), you must notify the Regional Supervisor in writing.

(a) When you prepare the notice, you must:

(1) Sign and date the notice;

(2) Provide the names of the vessel, its operator, and the person(s) in charge; the specific type(s) of operations you will conduct; and the instrumentation/techniques and vessel navigation system you will use;

(3) Provide expected start and completion dates and the location of the activity; and

(4) Describe the potential adverse environmental effects of the proposed activity and any mitigation to eliminate or minimize these effects on the marine, coastal, and human environment.

(b) The Regional Supervisor may require you to:

(1) Give written notice to MMS at least 15 calendar days before you conduct any other ancillary activity (see § 250.207(b) and (c)) in addition to those listed in § 250.207(a); and

(2) Notify other users of the OCS before you conduct any ancillary activity.

§ 250.209 What is the MMS review process for the notice?

The Regional Supervisor will review any notice required under § 250.208(a) and (b)(1) to ensure that your ancillary activity complies with the performance standards listed in § 250.202(a), (b), (d), and (e). The Regional Supervisor may notify you that your ancillary activity does not comply with those standards. In such a case, the Regional Supervisor will require you to submit an EP, DPP, or DOCD and you may not start your ancillary activity until the Regional Supervisor approves the EP, DPP, or DOCD.

§ 250.210 If I conduct ancillary activities, what reporting and data/information retention requirements must I satisfy?

(a) *Reporting.* The Regional Supervisor may require you to prepare and submit reports that summarize and analyze data or information obtained or derived from your ancillary activities. When applicable, MMS will protect and disclose the data and information in these reports in accordance with § 250.197(b).

(b) *Data and information retention.* You must retain copies of all original data and information, including navigation data, obtained or derived from your G&G explorations and development G&G activities (see § 250.207(a)), including any such data and information you obtained from previous leaseholders or unit operators. You must submit such data and information to MMS for inspection and possible retention upon request at any time before lease or unit termination. When applicable, MMS will protect and disclose such submitted data and information in accordance with § 250.197(b).

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 25200, May 4, 2007]

CONTENTS OF EXPLORATION PLANS (EP)

§ 250.211 What must the EP include?

Your EP must include the following:

(a) *Description, objectives, and schedule.* A description, discussion of the objectives, and tentative schedule (from start to completion) of the exploration activities that you propose to undertake. Examples of exploration activities include exploration drilling, well test flaring, installing a well protection structure, and temporary well abandonment.

(b) *Location.* A map showing the surface location and water depth of each proposed well and the locations of all associated drilling unit anchors.

(c) *Drilling unit.* A description of the drilling unit and associated equipment you will use to conduct your proposed exploration activities, including a brief description of its important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels, oil, and lubricants that will be stored on the facility (see third definition of ''facility'' under § 250.105).

(d) *Service fee.* You must include payment of the service fee listed in § 250.125.

[70 FR 51501, Aug. 30, 2005, as amended at 71 FR 40911, July 19, 2006]

§ 250.212 What information must accompany the EP?

The following information must accompany your EP:

(a) General information required by § 250.213;

(b) Geological and geophysical (G&G) information required by § 250.214;

(c) Hydrogen sulfide information required by § 250.215;

(d) Biological, physical, and socioeconomic information required by § 250.216;

(e) Solid and liquid wastes and discharges information and cooling water intake information required by § 250.217;

(f) Air emissions information required by § 250.218;

(g) Oil and hazardous substance spills information required by § 250.219;

(h) Alaska planning information required by § 250.220;

(i) Environmental monitoring information required by § 250.221;

(j) Lease stipulations information required by § 250.222;

(k) Mitigation measures information required by § 250.223;

(l) Support vessels and aircraft information required by § 250.224;

(m) Onshore support facilities information required by § 250.225;

(n) Coastal zone management information required by § 250.226;

(o) Environmental impact analysis information required by § 250.227; and

(p) Administrative information required by § 250.228.

§ 250.213 What general information must accompany the EP?

The following general information must accompany your EP:

(a) *Applications and permits.* A listing, including filing or approval status, of the Federal, State, and local application approvals or permits you must obtain to conduct your proposed exploration activities.

(b) *Drilling fluids.* A table showing the projected amount, discharge rate, and chemical constituents for each type (*i.e.*, water-based, oil-based, synthetic-based) of drilling fluid you plan to use to drill your proposed exploration wells.

(c) *Chemical products.* A table showing the name and brief description, quantities to be stored, storage method, and rates of usage of the chemical products you will use to conduct your proposed exploration activities. List only those chemical products you will store or use in quantities greater than the amounts defined as Reportable Quantities in 40 CFR part 302, or amounts specified by the Regional Supervisor.

(d) *New or unusual technology.* A description and discussion of any new or unusual technology (see definition under § 250.200) you will use to carry out your proposed exploration activities. In the public information copies of your EP, you may exclude any proprietary information from this description. In that case, include a brief discussion of the general subject matter of the omitted information. If you will not use any new or unusual technology to carry out your proposed exploration activities, include a statement so indicating.

(e) *Bonds, oil spill financial responsibility, and well control statements.* Statements attesting that:

(1) The activities and facilities proposed in your EP are or will be covered by an appropriate bond under 30 CFR part 256, subpart I;

(2) You have demonstrated or will demonstrate oil spill financial responsibility for facilities proposed in your EP according to 30 CFR part 253; and

(3) You have or will have the financial capability to drill a relief well and conduct other emergency well control operations.

(f) *Suspensions of operations.* A brief discussion of any suspensions of operations that you anticipate may be necessary in the course of conducting your activities under the EP.

(g) *Blowout scenario.* A scenario for the potential blowout of the proposed well in your EP that you expect will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum duration of the potential blowout. Also, discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Estimate the time it would take to drill a relief well.

(h) *Contact.* The name, address (e-mail address, if available), and telephone number of the person with whom the Regional Supervisor and any affected State(s) can communicate about your EP.

§ 250.214 What geological and geophysical (G&G) information must accompany the EP?

The following G&G information must accompany your EP:

(a) *Geological description.* A geological description of the prospect(s).

(b) *Structure contour maps.* Current structure contour maps (depth-based, expressed in feet subsea) drawn on the top of each prospective hydrocarbon-bearing reservoir showing the locations of proposed wells.

(c) *Two-dimensional (2–D) or three-dimensional (3–D) seismic lines.* Copies of migrated and annotated 2–D or 3–D seismic lines (with depth scale) intersecting at or near your proposed well locations. You are not required to conduct both 2–D and 3–D seismic surveys if you choose to conduct only one type of survey. If you have conducted both types of surveys, the Regional Supervisor may instruct you to submit the results of both surveys. You must interpret and display this information. Because of its volume, provide this information as an enclosure to only one proprietary copy of your EP.

(d) *Geological cross-sections.* Interpreted geological cross-sections showing the location and depth of each proposed well.

(e) *Shallow hazards report.* A shallow hazards report based on information obtained from a high-resolution geophysical survey, or a reference to such report if you have already submitted it to the Regional Supervisor.

(f) *Shallow hazards assessment.* For each proposed well, an assessment of any seafloor and subsurface geological and manmade features and conditions that may adversely affect your proposed drilling operations.

(g) *High-resolution seismic lines.* A copy of the high-resolution survey line closest to each of your proposed well locations. Because of its volume, provide this information as an enclosure to only one proprietary copy of your EP. You are not required to provide this information if the surface location of your proposed well has been approved in a previously submitted EP, DPP, or DOCD.

(h) *Stratigraphic column.* A generalized biostratigraphic/lithostratigraphic column from the surface to the total depth of the prospect.

(i) *Time-versus-depth chart.* A seismic travel time-versus-depth chart based on the appropriate velocity analysis in the area of interpretation and specifying the geodetic datum.

(j) *Geochemical information.* A copy of any geochemical reports you used or generated.

(k) *Future G&G activities.* A brief description of the types of G&G explorations and development G&G activities you may conduct for lease or unit purposes after your EP is approved.

§ 250.215 What hydrogen sulfide (H_2S) information must accompany the EP?

The following H_2S information, as applicable, must accompany your EP:

(a) *Concentration.* The estimated concentration of any H_2S you might encounter while you conduct your proposed exploration activities.

(b) *Classification.* Under § 250.490(c), a request that the Regional Supervisor classify the area of your proposed exploration activities as either H_2S absent, H_2S present, or H_2S unknown. Provide sufficient information to justify your request.

(c) *H_2S Contingency Plan.* If you ask the Regional Supervisor to classify the area of your proposed exploration activities as either H_2S present or H_2S unknown, an H_2S Contingency Plan prepared under § 250.490(f), or a reference to an approved or submitted H_2S Contingency Plan that covers the proposed exploration activities.

(d) *Modeling report.* If you modeled a potential H_2S release when developing your EP, modeling report or the modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(1) The analysis in the modeling report must be specific to the particular site of your proposed exploration activities, and must consider any nearby human-occupied OCS facilities, shipping lanes, fishery areas, and other points where humans may be subject to potential exposure from an H_2S release from your proposed exploration activities.

(2) If any H_2S emissions are projected to affect an onshore location in concentrations greater than 10 parts per million, the modeling analysis must be consistent with the Environmental Protection Agency's (EPA) risk management plan methodologies outlined in 40 CFR part 68.

§ 250.216 What biological, physical, and socioeconomic information must accompany the EP?

If you obtain the following information in developing your EP, or if the Regional Supervisor requires you to obtain it, you must include a report, or the information obtained, or a reference to such a report or information if you have already submitted it to the Regional Supervisor, as accompanying information:

(a) *Biological environment reports.* Site-specific information on chemosynthetic communities, federally listed threatened or endangered species, marine mammals protected under the Marine Mammal Protection Act (MMPA), sensitive underwater features, marine sanctuaries, critical habitat designated under the Endangered Species Act (ESA), or other areas of biological concern.

(b) *Physical environment reports.* Site-specific meteorological, physical oceanographic, geotechnical reports, or archaeological reports (if required under § 250.194).

(c) *Socioeconomic study reports.* Socioeconomic information regarding your proposed exploration activities.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18584, Apr. 13, 2007]

§ 250.217 What solid and liquid wastes and discharges information and cooling water intake information must accompany the EP?

The following solid and liquid wastes and discharges information and cooling water intake information must accompany your EP:

(a) *Projected wastes.* A table providing the name, brief description, projected quantity, and composition of solid and liquid wastes (such as spent drilling fluids, drill cuttings, trash, sanitary and domestic wastes, and chemical product wastes) likely to be generated by your proposed exploration activities. Describe:

(1) The methods you used for determining this information; and

(2) Your plans for treating, storing, and downhole disposal of these wastes at your drilling location(s).

(b) *Projected ocean discharges.* If any of your solid and liquid wastes will be discharged overboard, or are planned discharges from manmade islands:

(1) A table showing the name, projected amount, and rate of discharge for each waste type; and

(2) A description of the discharge method (such as shunting through a downpipe, etc.) you will use.

(c) *National Pollutant Discharge Elimination System (NPDES) permit.* (1) A discussion of how you will comply with the provisions of the applicable general NPDES permit that covers your proposed exploration activities; or

(2) A copy of your application for an individual NPDES permit. Briefly describe the major discharges and methods you will use for compliance.

(d) *Modeling report.* The modeling report or the modeling results (if you modeled the discharges of your projected solid or liquid wastes when developing your EP), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(e) *Projected cooling water intake.* A table for each cooling water intake structure likely to be used by your proposed exploration activities that includes a brief description of the cooling water intake structure, daily water intake rate, water intake through screen velocity, percentage of water intake used for cooling water, mitigation measures for reducing impingement and entrainment of aquatic organisms, and biofouling prevention measures.

§250.218 What air emissions information must accompany the EP?

The following air emissions information, as applicable, must accompany your EP:

(a) *Projected emissions*. Tables showing the projected emissions of sulphur dioxide (SO_2), particulate matter in the form of PM_{10} and $PM_{2.5}$ when applicable, nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) that will be generated by your proposed exploration activities.

(1) For each source on or associated with the drilling unit (including well test flaring and well protection structure installation), you must list:

(i) The projected peak hourly emissions;

(ii) The total annual emissions in tons per year;

(iii) Emissions over the duration of the proposed exploration activities;

(iv) The frequency and duration of emissions; and

(v) The total of all emissions listed in paragraphs (a)(1)(i) through (iv) of this section.

(2) You must provide the basis for all calculations, including engine size and rating, and applicable operational information.

(3) You must base the projected emissions on the maximum rated capacity of the equipment on the proposed drilling unit under its physical and operational design.

(4) If the specific drilling unit has not yet been determined, you must use the maximum emission estimates for the type of drilling unit you will use.

(b) *Emission reduction measures*. A description of any proposed emission reduction measures, including the affected source(s), the emission reduction control technologies or procedures, the quantity of reductions to be achieved, and any monitoring system you propose to use to measure emissions.

(c) *Processes, equipment, fuels, and combustibles*. A description of processes, processing equipment, combustion equipment, fuels, and storage units. You must include the characteristics and the frequency, duration, and maximum burn rate of any well test fluids to be burned.

(d) *Distance to shore*. Identification of the distance of your drilling unit from the mean high water mark (mean higher high water mark on the Pacific coast) of the adjacent State.

(e) *Non-exempt drilling units*. A description of how you will comply with §250.303 when the projected emissions of SO_2, PM, NO_X, CO, or VOC, that will be generated by your proposed exploration activities, are greater than the respective emission exemption amounts ''E'' calculated using the formulas in §250.303(d). When MMS requires air quality modeling, you must use the guidelines in Appendix W of 40 CFR part 51 with a model approved by the Director. Submit the best available meteorological information and data consistent with the model(s) used.

(f) *Modeling report*. A modeling report or the modeling results (if §250.303 requires you to use an approved air quality model to model projected air emissions in developing your EP), or a reference to such a report or results if you have already submitted it to the Regional Supervisor.

§250.219 What oil and hazardous substance spills information must accompany the EP?

The following information regarding potential spills of oil (see definition under 30 CFR 254.6) and hazardous substances (see definition under 40 CFR part 116) as applicable, must accompany your EP:

(a) *Oil spill response planning*. The material required under paragraph (a)(1) or (a)(2) of this section:

(1) An Oil Spill Response Plan (OSRP) for the facilities you will use to conduct your exploration activities prepared according to the requirements of 30 CFR part 254, subpart B; or

(2) Reference to your approved regional OSRP (see 30 CFR 254.3) to include:

(i) A discussion of your regional OSRP;

(ii) The location of your primary oil spill equipment base and staging area;

(iii) The name(s) of your oil spill removal organization(s) for both equipment and personnel;

(iv) The calculated volume of your worst case discharge scenario (see 30 CFR 254.26(a)), and a comparison of the appropriate worst case discharge scenario in your approved regional OSRP with the worst case discharge scenario that could result from your proposed exploration activities; and

(v) A description of the worst case discharge scenario that could result from your proposed exploration activities (see 30 CFR 254.26(b), (c), (d), and (e)).

(b) *Modeling report.* If you model a potential oil or hazardous substance spill in developing your EP, a modeling report or the modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

§ 250.220 If I propose activities in the Alaska OCS Region, what planning information must accompany the EP?

If you propose exploration activities in the Alaska OCS Region, the following planning information must accompany your EP:

(a) *Emergency plans.* A description of your emergency plans to respond to a blowout, loss or disablement of a drilling unit, and loss of or damage to support craft.

(b) *Critical operations and curtailment procedures.* Critical operations and curtailment procedures for your exploration activities. The procedures must identify ice conditions, weather, and other constraints under which the exploration activities will either be curtailed or not proceed.

§ 250.221 What environmental monitoring information must accompany the EP?

The following environmental monitoring information, as applicable, must accompany your EP:

(a) *Monitoring systems.* A description of any existing and planned monitoring systems that are measuring, or will measure, environmental conditions or will provide project-specific data or information on the impacts of your exploration activities.

(b) *Incidental takes.* If there is reason to believe that protected species may be incidentally taken by planned exploration activities, you must describe how you will monitor for incidental take of:

(1) Threatened and endangered species listed under the ESA and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

(c) *Flower Garden Banks National Marine Sanctuary (FGBNMS).* If you propose to conduct exploration activities within the protective zones of the FGBNMS, a description of your provisions for monitoring the impacts of an oil spill on the environmentally sensitive resources at the FGBNMS.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18584, Apr. 13, 2007]

§ 250.222 What lease stipulations information must accompany the EP?

A description of the measures you took, or will take, to satisfy the conditions of lease stipulations related to your proposed exploration activities must accompany your EP.

§ 250.223 What mitigation measures information must accompany the EP?

(a) If you propose to use any measures beyond those required by the regulations in this part to minimize or mitigate environmental impacts from your proposed exploration activities, a description of the measures you will use must accompany your EP.

(b) If there is reason to believe that protected species may be incidentally taken by planned exploration activities, you must include mitigation measures designed to avoid or minimize the incidental take of:

(1) Threatened and endangered species listed under the ESA and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

[72 FR 18585, Apr. 13, 2007]

§ 250.224 What information on support vessels, offshore vehicles, and aircraft you will use must accompany the EP?

The following information on the support vessels, offshore vehicles, and aircraft you will use must accompany your EP:

(a) *General.* A description of the crew boats, supply boats, anchor handling vessels, tug boats, barges, ice management vessels, other vessels, offshore vehicles, and aircraft you will use to support your exploration activities. The description of vessels and offshore vehicles must estimate the storage capacity of their fuel tanks and the frequency of their visits to your drilling unit.

(b) *Air emissions.* A table showing the source, composition, frequency, and duration of the air emissions likely to be generated by the support vessels, offshore vehicles, and aircraft you will use that will operate within 25 miles of your drilling unit.

(c) *Drilling fluids and chemical products transportation.* A description of the transportation method and quantities of drilling fluids and chemical products (see § 250.213(b) and (c)) you will transport from the onshore support facilities you will use to your drilling unit.

(d) *Solid and liquid wastes transportation.* A description of the transportation method and a brief description of the composition, quantities, and destination(s) of solid and liquid wastes (see § 250.217(a)) you will transport from your drilling unit.

(e) *Vicinity map.* A map showing the location of your proposed exploration activities relative to the shoreline. The map must depict the primary route(s) the support vessels and aircraft will use when traveling between the onshore support facilities you will use and your drilling unit.

§ 250.225 What information on the onshore support facilities you will use must accompany the EP?

The following information on the onshore support facilities you will use must accompany your EP:

(a) *General.* A description of the onshore facilities you will use to provide supply and service support for your proposed exploration activities (e.g., service bases and mud company docks).

(1) Indicate whether the onshore support facilities are existing, to be constructed, or to be expanded.

(2) If the onshore support facilities are, or will be, located in areas not adjacent to the Western GOM, provide a timetable for acquiring lands (including rights-of-way and easements) and constructing or expanding the facilities. Describe any State or Federal permits or approvals (dredging, filling, etc.) that would be required for constructing or expanding them.

(b) *Air emissions.* A description of the source, composition, frequency, and duration of the air emissions (attributable to your proposed exploration activities) likely to be generated by the onshore support facilities you will use.

(c) *Unusual solid and liquid wastes.* A description of the quantity, composition, and method of disposal of any unusual solid and liquid wastes (attributable to your proposed exploration activities) likely to be generated by the onshore support facilities you will use. Unusual wastes are those wastes not specifically addressed in the relevant National Pollution Discharge Elimination System (NPDES) permit.

(d) *Waste disposal.* A description of the onshore facilities you will use to store and dispose of solid and liquid wastes generated by your proposed exploration activities (see § 250.217) and the types and quantities of such wastes.

§ 250.226 What Coastal Zone Management Act (CZMA) information must accompany the EP?

The following CZMA information must accompany your EP:

(a) *Consistency certification.* A copy of your consistency certification under section 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76(d) stating that the proposed exploration activities described in detail in this EP comply with (name of State(s)) approved coastal management program(s) and will be conducted in a manner that is consistent with such program(s); and

(b) *Other information.* ''Information'' as required by 15 CFR 930.76(a) and 15 CFR 930.58(a)(2)) and ''Analysis'' as required by 15 CFR 930.58(a)(3).

§ 250.227 What environmental impact analysis (EIA) information must accompany the EP?

The following EIA information must accompany your EP:

(a) *General requirements.* Your EIA must:

(1) Assess the potential environmental impacts of your proposed exploration activities;

(2) Be project specific; and

(3) Be as detailed as necessary to assist the Regional Supervisor in complying with the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4321 *et seq.*) and other relevant Federal laws such as the ESA and the MMPA.

(b) *Resources, conditions, and activities.* Your EIA must describe those resources, conditions, and activities listed below that could be affected by your proposed exploration activities, or that could affect the construction and operation of facilities or structures, or the activities proposed in your EP.

(1) Meteorology, oceanography, geology, and shallow geological or manmade hazards;

(2) Air and water quality;

(3) Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, and plant life;

(4) Threatened or endangered species and their critical habitat as defined by the Endangered Species Act of 1973;

(5) Sensitive biological resources or habitats such as essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, and calving grounds;

(6) Archaeological resources;

(7) Socioeconomic resources including employment, existing offshore and coastal infrastructure (including major sources of supplies, services, energy, and water), land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including typical fishing seasons, location, and type), minority and lower income groups, and coastal zone management programs;

(8) Coastal and marine uses such as military activities, shipping, and mineral exploration or development; and

(9) Other resources, conditions, and activities identified by the Regional Supervisor.

(c) *Environmental impacts.* Your EIA must:

(1) Analyze the potential direct and indirect impacts (including those from accidents, cooling water intake structures, and those identified in relevant ESA biological opinions such as, but not limited to, those from noise, vessel collisions, and marine trash and debris) that your proposed exploration activities will have on the identified resources, conditions, and activities;

(2) Analyze any potential cumulative impacts from other activities to those identified resources, conditions, and activities potentially impacted by your proposed exploration activities;

(3) Describe the type, severity, and duration of these potential impacts and their biological, physical, and other consequences and implications;

(4) Describe potential measures to minimize or mitigate these potential impacts; and

(5) Summarize the information you incorporate by reference.

(d) *Consultation.* Your EIA must include a list of agencies and persons with whom you consulted, or with whom you will be consulting, regarding potential impacts associated with your proposed exploration activities.

(e) *References cited.* Your EIA must include a list of the references that you cite in the EIA.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.228 What administrative information must accompany the EP?

The following administrative information must accompany your EP:

(a) *Exempted information description (public information copies only).* A description of the general subject matter of the proprietary information that is included in the proprietary copies of your EP or its accompanying information.

(b) *Bibliography.* (1) If you reference a previously submitted EP, DPP, DOCD, study report, survey report, or other material in your EP or its accompanying information, a list of the referenced material; and

(2) The location(s) where the Regional Supervisor can inspect the cited referenced material if you have not submitted it.

REVIEW AND DECISION PROCESS FOR THE EP

§ 250.231 After receiving the EP, what will MMS do?

(a) *Determine whether deemed submitted.* Within 15 working days after receiving your proposed EP and its accompanying information, the Regional Supervisor will review your submission and deem your EP submitted if:

(1) The submitted information, including the information that must accompany the EP (refer to the list in § 250.212), fulfills requirements and is sufficiently accurate;

(2) You have provided all needed additional information (see § 250.201(b)); and

(3) You have provided the required number of copies (see § 250.206(a)).

(b) *Identify problems and deficiencies.* If the Regional Supervisor determines that you have not met one or more of the conditions in paragraph (a) of this section, the Regional Supervisor will notify you of the problem or deficiency within 15 working days after the Regional Supervisor receives your EP and its accompanying information. The Regional Supervisor will not deem your EP submitted until you have corrected all problems or deficiencies identified in the notice.

(c) *Deemed submitted notification.* The Regional Supervisor will notify you when the EP is deemed submitted.

§ 250.232 What actions will MMS take after the EP is deemed submitted?

(a) *State and CZMA consistency reviews.* Within 2 working days after deeming your EP submitted under § 250.231, the Regional Supervisor will use receipted mail or alternative method to send a public information copy of the EP and its accompanying information to the following:

(1) *The Governor of each affected State.* The Governor has 21 calendar days after receiving your deemed-submitted EP to submit comments. The Regional Supervisor will not consider comments received after the deadline.

(2) *The CZMA agency of each affected State.* The CZMA consistency review period under section 307(c)(3)(B)(ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(ii)) and 15 CFR 930.78 begins when the State's CZMA agency receives a copy of your deemed-submitted EP, consistency certification, and required necessary data and information (see 15 CFR 930.77(a)(1)).

(b) *MMS compliance review.* The Regional Supervisor will review the exploration activities described in your proposed EP to ensure that they conform to the performance standards in § 250.202.

(c) *MMS environmental impact evaluation.* The Regional Supervisor will evaluate the environmental impacts of the activities described in your proposed EP and prepare environmental documentation under the National Environmental Policy Act (NEPA) (42 U.S.C. 4321 *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508).

(d) *Amendments.* During the review of your proposed EP, the Regional Supervisor may require you, or you may elect, to change your EP. If you elect to amend your EP, the Regional Supervisor may determine that your EP, as amended, is subject to the requirements of § 250.231.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 25200, May 4, 2007]

§ 250.233 What decisions will MMS make on the EP and within what timeframe?

(a) *Timeframe.* The Regional Supervisor will take one of the actions shown in the table in paragraph (b) of this section within 30 calendar days after the Regional Supervisor deems your EP submitted under § 250.231, or receives the last amendment to your proposed EP, whichever occurs later.

(b) *MMS decision.* By the deadline in paragraph (a) of this section, the Regional Supervisor will take one of the following actions:

The regional supervisor will . . .	If . . .	And then . . .
(1) Approve your EP	It complies with all applicable requirements	The Regional Supervisor will notify you in writing of the decision and may require you to meet certain conditions, including those to provide monitoring information.
(2) Require you to modify your proposed EP.	The Regional Supervisor finds that it is inconsistent with the lease, the Act, the regulations prescribed under the Act, or other Federal laws.	The Regional Supervisor will notify you in writing of the decision and describe the modifications you must make to your proposed EP to ensure it complies with all applicable requirements.
(3) Disapprove your EP ..	Your proposed activities would probably cause serious harm or damage to life (including fish or other aquatic life); property; any mineral (in areas leased or not leased); the national security or defense; or the marine, coastal, or human environment; and you cannot modify your proposed activities to avoid such condition(s).	(i) The Regional Supervisor will notify you in writing of the decision and describe the reason(s) for disapproving your EP. (ii) MMS may cancel your lease and compensate you under 43 U.S.C. 1334(a)(2)(C) and the implementing regulations in §§ 250.182, 250.184, and 250.185 and 30 CFR 256.77.

[70 FR 51501, Aug. 30, 2005, as amended at 74 FR 46908, Sept. 14, 2009]

§ 250.234 How do I submit a modified EP or resubmit a disapproved EP, and when will MMS make a decision?

(a) *Modified EP.* If the Regional Supervisor requires you to modify your proposed EP under § 250.233(b)(2), you must submit the modification(s) to the Regional Supervisor in the same manner as for a new EP. You need submit only information related to the proposed modification(s).

(b) *Resubmitted EP.* If the Regional Supervisor disapproves your EP under § 250.233(b)(3), you may resubmit the disapproved EP if there is a change in the conditions that were the basis of its disapproval.

(c) *MMS review and timeframe.* The Regional Supervisor will use the performance standards in § 250.202 to either approve, require you to further modify, or disapprove your modified or resubmitted EP. The Regional Supervisor will make a decision within 30 calendar days after the Regional Supervisor deems your modified or resubmitted EP to be submitted, or receives the last amendment to your modified or resubmitted EP, whichever occurs later.

§ 250.235 If a State objects to the EP's coastal zone consistency certification, what can I do?

If an affected State objects to the coastal zone consistency certification accompanying your proposed EP within the timeframe prescribed in § 250.233(a) or § 250.234(c), you may do one of the following:

(a) *Amend your EP.* Amend your EP to accommodate the State's objection and submit the amendment to the Regional Supervisor for approval. The amendment needs to only address information related to the State's objection.

(b) *Appeal.* Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either:

(1) Grant your appeal by finding, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)), that each activity described in detail in your EP is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of national security; or

(2) Deny your appeal, in which case you may amend your EP as described in paragraph (a) of this section.

(c) *Withdraw your EP.* Withdraw your EP if you decide not to conduct your proposed exploration activities.

[70 FR 51501, Aug. 30, 2005; 71 FR 12438, Mar. 10, 2006]

CONTENTS OF DEVELOPMENT AND PRODUCTION PLANS (DPP) AND DEVELOPMENT OPERATIONS COORDINATION DOCUMENTS (DOCD)

§ 250.241 What must the DPP or DOCD include?

Your DPP or DOCD must include the following:

(a) *Description, objectives, and schedule.* A description, discussion of the objectives, and tentative schedule (from start to completion) of the development and production activities you propose to undertake. Examples of development and production activities include:

(1) Development drilling;

(2) Well test flaring;

(3) Installation of production platforms, satellite structures, subsea wellheads and manifolds, and lease term pipelines (see definition at § 250.105); and

(4) Installation of production facilities and conduct of production operations.

(b) *Location.* The location and water depth of each of your proposed wells and production facilities. Include a map showing the surface and bottom-hole location and water depth of each proposed well, the surface location of each production facility, and the locations of all associated drilling unit and construction barge anchors.

(c) *Drilling unit.* A description of the drilling unit and associated equipment you will use to conduct your proposed development drilling activities. Include a brief description of its important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels and oil that will be stored on the facility (see third definition of ''facility'' under § 250.105).

(d) *Production facilities.* A description of the production platforms, satellite structures, subsea wellheads and manifolds, lease term pipelines (see definition at § 250.105), production facilities, umbilicals, and other facilities you will use to conduct your proposed development and production activities. Include a brief description of their important safety and pollution prevention features, and a table indicating the type and the estimated maximum quantity of fuels and oil that will be stored on the facility (see third definition of ''facility'' under § 250.105).

(e) *Service fee.* You must include payment of the service fee listed in § 250.125.

[70 FR 51501, Aug. 30, 2005, as amended at 71 FR 40911, July 19, 2006]

§ 250.242 What information must accompany the DPP or DOCD?

The following information must accompany your DPP or DOCD.

(a) General information required by § 250.243;

(b) G&G information required by § 250.244;

(c) Hydrogen sulfide information required by § 250.245;

(d) Mineral resource conservation information required by § 250.246;

(e) Biological, physical, and socioeconomic information required by § 250.247;

(f) Solid and liquid wastes and discharges information and cooling water intake information required by § 250.248;

(g) Air emissions information required by § 250.249;

(h) Oil and hazardous substance spills information required by § 250.250;

(i) Alaska planning information required by § 250.251;

(j) Environmental monitoring information required by § 250.252;

(k) Lease stipulations information required by § 250.253;

(l) Mitigation measures information required by § 250.254;

(m) Decommissioning information required by § 250.255;

(n) Related facilities and operations information required by § 250.256;

(o) Support vessels and aircraft information required by § 250.257;

(p) Onshore support facilities information required by § 250.258;

(q) Sulphur operations information required by § 250.259;

(r) Coastal zone management information required by § 250.260;

(s) Environmental impact analysis information required by § 250.261; and

(t) Administrative information required by § 250.262.

§ 250.243 What general information must accompany the DPP or DOCD?

The following general information must accompany your DPP or DOCD:

(a) *Applications and permits.* A listing, including filing or approval status, of the Federal, State, and local application approvals or permits you must obtain to carry out your proposed development and production activities.

(b) *Drilling fluids.* A table showing the projected amount, discharge rate, and chemical constituents for each type (*i.e.*, water based, oil based, synthetic based) of drilling fluid you plan to use to drill your proposed development wells.

(c) *Production.* The following production information:

(1) Estimates of the average and peak rates of production for each type of production and the life of the reservoir(s) you intend to produce; and

(2) The chemical and physical characteristics of the produced oil (see definition under 30 CFR 254.6) that you will handle or store at the facilities you will use to conduct your proposed development and production activities.

(d) *Chemical products.* A table showing the name and brief description, quantities to be stored, storage method, and rates of usage of the chemical products you will use to conduct your proposed development and production activities. You need list only those chemical products you will store or use in quantities greater than the amounts defined as Reportable Quantities in 40 CFR part 302, or amounts specified by the Regional Supervisor.

(e) *New or unusual technology.* A description and discussion of any new or unusual technology (see definition under §250.200) you will use to carry out your proposed development and production activities. In the public information copies of your DPP or DOCD, you may exclude any proprietary information from this description. In that case, include a brief discussion of the general subject matter of the omitted information. If you will not use any new or unusual technology to carry out your proposed development and production activities, include a statement so indicating.

(f) *Bonds, oil spill financial responsibility, and well control statements.* Statements attesting that:

(1) The activities and facilities proposed in your DPP or DOCD are or will be covered by an appropriate bond under 30 CFR part 256, subpart I;

(2) You have demonstrated or will demonstrate oil spill financial responsibility for facilities proposed in your DPP or DOCD, according to 30 CFR part 253; and

(3) You have or will have the financial capability to drill a relief well and conduct other emergency well control operations.

(g) *Suspensions of production or operations.* A brief discussion of any suspensions of production or suspensions of operations that you anticipate may be necessary in the course of conducting your activities under the DPP or DOCD.

(h) *Blowout scenario.* A scenario for a potential blowout of the proposed well in your DPP or DOCD that you expect will have the highest volume of liquid hydrocarbons. Include the estimated flow rate, total volume, and maximum duration of the potential blowout. Also, discuss the potential for the well to bridge over, the likelihood for surface intervention to stop the blowout, the availability of a rig to drill a relief well, and rig package constraints. Estimate the time it would take to drill a relief well.

(i) *Contact.* The name, mailing address, (e-mail address if available), and telephone number of the person with whom the Regional Supervisor and the affected State(s) can communicate about your DPP or DOCD.

§ 250.244 What geological and geophysical (G&G) information must accompany the DPP or DOCD?

The following G&G information must accompany your DPP or DOCD:

(a) *Geological description.* A geological description of the prospect(s).

(b) *Structure contour maps.* Current structure contour maps (depth-based, expressed in feet subsea) showing depths of expected productive formations and the locations of proposed wells.

(c) *Two dimensional (2–D) or three-dimensional (3–D) seismic lines.* Copies of migrated and annotated 2–D or 3–D seismic lines (with depth scale) intersecting at or near your proposed well locations. You are not required to conduct both 2–D and 3–D seismic surveys if you choose to conduct only one type of survey. If you have conducted both types of surveys, the Regional Supervisor may instruct you to submit the results of both surveys. You must interpret and display this information.

Provide this information as an enclosure to only one proprietary copy of your DPP or DOCD.

(d) *Geological cross-sections.* Interpreted geological cross-sections showing the depths of expected productive formations.

(e) *Shallow hazards report.* A shallow hazards report based on information obtained from a high-resolution geophysical survey, or a reference to such report if you have already submitted it to the Regional Supervisor.

(f) *Shallow hazards assessment.* For each proposed well, an assessment of any seafloor and subsurface geologic and manmade features and conditions that may adversely affect your proposed drilling operations.

(g) *High resolution seismic lines.* A copy of the high-resolution survey line closest to each of your proposed well locations. Because of its volume, provide this information as an enclosure to only one proprietary copy of your DPP or DOCD. You are not required to provide this information if the surface location of your proposed well has been approved in a previously submitted EP, DPP, or DOCD.

(h) *Stratigraphic column.* A generalized biostratigraphic/lithostratigraphic column from the surface to the total depth of each proposed well.

(i) *Time-versus-depth chart.* A seismic travel time-versus-depth chart based on the appropriate velocity analysis in the area of interpretation and specifying the geodetic datum.

(j) *Geochemical information.* A copy of any geochemical reports you used or generated.

(k) *Future G&G activities.* A brief description of the G&G explorations and development G&G activities that you may conduct for lease or unit purposes after your DPP or DOCD is approved.

§ 250.245 What hydrogen sulfide (H_2S) information must accompany the DPP or DOCD?

The following H_2S information, as applicable, must accompany your DPP or DOCD:

(a) *Concentration.* The estimated concentration of any H_2S you might encounter or handle while you conduct your proposed development and production activities.

(b) *Classification.* Under § 250.490(c), a request that the Regional Supervisor classify the area of your proposed development and production activities as either H_2S absent, H_2S present, or H_2S unknown. Provide sufficient information to justify your request.

(c) *H_2S Contingency Plan.* If you request that the Regional Supervisor classify the area of your proposed development and production activities as either H_2S present or H_2S unknown, an H_2S Contingency Plan prepared under § 250.490(f), or a reference to an approved or submitted H_2S Contingency Plan that covers the proposed development and production activities.

(d) *Modeling report.* (1) If you have determined or estimated that the concentration of any H_2S you may encounter or handle while you conduct your development and production activities will be greater than 500 parts per million (ppm), you must:

(i) Model a potential worst case H_2S release from the facilities you will use to conduct your proposed development and production activities; and

(ii) Include a modeling report or modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(2) The analysis in the modeling report must be specific to the particular site of your development and production activities, and must consider any nearby human-occupied OCS facilities, shipping lanes, fishery areas, and other points where humans may be subject to potential exposure from an H_2S release from your proposed activities.

(3) If any H_2S emissions are projected to affect an onshore location in concentrations greater than 10 ppm, the modeling analysis must be consistent with the EPA's risk management plan methodologies outlined in 40 CFR part 68.

§ 250.246 What mineral resource conservation information must accompany the DPP or DOCD?

The following mineral resource conservation information, as applicable, must accompany your DPP or DOCD:

(a) *Technology and reservoir engineering practices and procedures.* A description of the technology and reservoir engineering practices and procedures you will use to increase the ultimate recovery of oil and gas (e.g., secondary, tertiary, or other enhanced recovery practices). If you will not use enhanced recovery practices initially, provide an explanation of the methods you considered and the reasons why you are not using them.

(b) *Technology and recovery practices and procedures.* A description of the technology and recovery practices and procedures you will use to ensure optimum recovery of oil and gas or sulphur.

(c) *Reservoir development.* A discussion of exploratory well results, other reservoir data, proposed well spacing, completion methods, and other relevant well plan information.

§ 250.247 What biological, physical, and socioeconomic information must accompany the DPP or DOCD?

If you obtain the following information in developing your DPP or DOCD, or if the Regional Supervisor requires you to obtain it, you must include a report, or the information obtained, or a reference to such a report or information if you have already submitted it to the Regional Supervisor, as accompanying information:

(a) *Biological environment reports.* Site-specific information on chemosynthetic communities, federally listed threatened or endangered species, marine mammals protected under the MMPA, sensitive underwater features, marine sanctuaries, critical habitat designated under the ESA, or other areas of biological concern.

(b) *Physical environment reports.* Site-specific meteorological, physical oceanographic, geotechnical reports, or archaeological reports (if required under § 250.194).

(c) *Socioeconomic study reports.* Socioeconomic information related to your proposed development and production activities.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.248 What solid and liquid wastes and discharges information and cooling water intake information must accompany the DPP or DOCD?

The following solid and liquid wastes and discharges information and cooling water intake information must accompany your DPP or DOCD:

(a) *Projected wastes.* A table providing the name, brief description, projected quantity, and composition of solid and liquid wastes (such as spent drilling fluids, drill cuttings, trash, sanitary and domestic wastes, produced waters, and chemical product wastes) likely to be generated by your proposed development and production activities. Describe:

(1) The methods you used for determining this information; and

(2) Your plans for treating, storing, and downhole disposal of these wastes at your facility location(s).

(b) *Projected ocean discharges.* If any of your solid and liquid wastes will be discharged overboard or are planned discharges from manmade islands:

(1) A table showing the name, projected amount, and rate of discharge for each waste type; and

(2) A description of the discharge method (such as shunting through a downpipe, adding to a produced water stream, etc.) you will use.

(c) *National Pollutant Discharge Elimination System (NPDES) permit.* (1) A discussion of how you will comply with the provisions of the applicable general NPDES permit that covers your proposed development and production activities; or

(2) A copy of your application for an individual NPDES permit. Briefly describe the major discharges and methods you will use for compliance.

(d) *Modeling report.* A modeling report or the modeling results (if you modeled the discharges of your projected solid or liquid wastes in developing your DPP or DOCD), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

(e) *Projected cooling water intake.* A table for each cooling water intake structure likely to be used by your proposed development and production activities that includes a brief description of the cooling water intake structure, daily water intake rate, water intake through-screen velocity, percentage of water intake used for cooling water, mitigation measures for reducing impingement and entrainment of aquatic organisms, and biofouling prevention measures.

§ 250.249 What air emissions information must accompany the DPP or DOCD?

The following air emissions information, as applicable, must accompany your DPP or DOCD:

(a) *Projected emissions.* Tables showing the projected emissions of sulphur dioxide (SO_2), particulate matter in the form of PM_{10} and $PM_{2.5}$ when applicable, nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) that will be generated by your proposed development and production activities.

(1) For each source on or associated with the facility you will use to conduct your proposed development and production activities, you must list:

(i) The projected peak hourly emissions;

(ii) The total annual emissions in tons per year;

(iii) Emissions over the duration of the proposed development and production activities;

(iv) The frequency and duration of emissions; and

(v) The total of all emissions listed in paragraph (a)(1)(i) through (iv) of this section.

(2) If your proposed production and development activities would result in an increase in the emissions of an air pollutant from your facility to an amount greater than the amount specified in your previously approved DPP or DOCD, you must show the revised emission rates for each source as well as the incremental change for each source.

(3) You must provide the basis for all calculations, including engine size and rating, and applicable operational information.

(4) You must base the projected emissions on the maximum rated capacity of the equipment and the maximum throughput of the facility you will use to conduct your proposed development and production activities under its physical and operational design.

(5) If the specific drilling unit has not yet been determined, you must use the maximum emission estimates for the type of drilling unit you will use.

(b) *Emission reduction measures.* A description of any proposed emission reduction measures, including the affected source(s), the emission reduction control technologies or procedures, the quantity of reductions to be achieved, and any monitoring system you propose to use to measure emissions.

(c) *Processes, equipment, fuels, and combustibles.* A description of processes, processing equipment, combustion equipment, fuels, and storage units. You must include the frequency, duration, and maximum burn rate of any flaring activity.

(d) *Distance to shore.* Identification of the distance of the site of your proposed development and production activities from the mean high water mark (mean higher high water mark on the Pacific coast) of the adjacent State.

(e) *Non-exempt facilities.* A description of how you will comply with § 250.303 when the projected emissions of SO_2, PM, NO_X, CO, or VOC that will be generated by your proposed development and production activities are greater than the respective emission exemption amounts ''E'' calculated using the formulas in § 250.303(d). When MMS requires air quality modeling, you must use the guidelines in Appendix W of 40 CFR part 51 with a model approved by the Director. Submit the best available meteorological information and data consistent with the model(s) used.

(f) *Modeling report.* A modeling report or the modeling results (if § 250.303 requires you to use an approved air quality model to model projected air emissions in developing your DPP or DOCD), or a reference to such report or results if you have already submitted it to the Regional Supervisor.

§ 250.250 What oil and hazardous substance spills information must accompany the DPP or DOCD?

The following information regarding potential spills of oil (see definition under 30 CFR 254.6) and hazardous substances (see definition under 40 CFR part 116), as applicable, must accompany your DPP or DOCD:

(a) *Oil spill response planning.* The material required under paragraph (a)(1) or (a)(2) of this section:

(1) An Oil Spill Response Plan (OSRP) for the facilities you will use to conduct your proposed development and production activities prepared according to the requirements of 30 CFR part 254, subpart B; or

(2) Reference to your approved regional OSRP (see 30 CFR 254.3) to include:

(i) A discussion of your regional OSRP;

(ii) The location of your primary oil spill equipment base and staging area;

(iii) The name(s) of your oil spill removal organization(s) for both equipment and personnel;

(iv) The calculated volume of your worst case discharge scenario (see 30 CFR 254.26(a)), and a comparison of the appropriate worst case discharge scenario in your approved regional OSRP with the worst case discharge scenario that could result from your proposed development and production activities; and

(v) A description of the worst case oil spill scenario that could result from your proposed development and production activities (see 30 CFR 254.26(b), (c), (d), and (e)).

(b) *Modeling report.* If you model a potential oil or hazardous substance spill in developing your DPP or DOCD, a modeling report or the modeling results, or a reference to such report or results if you have already submitted it to the Regional Supervisor.

§ 250.251 If I propose activities in the Alaska OCS Region, what planning information must accompany the DPP?

If you propose development and production activities in the Alaska OCS Region, the following planning information must accompany your DPP:

(a) *Emergency plans.* A description of your emergency plans to respond to a blowout, loss or disablement of a drilling unit, and loss of or damage to support craft; and

(b) *Critical operations and curtailment procedures.* Critical operations and curtailment procedures for your development and production activities. The procedures must identify ice conditions, weather, and other constraints under which the development and production activities will either be curtailed or not proceed.

§ 250.252 What environmental monitoring information must accompany the DPP or DOCD?

The following environmental monitoring information, as applicable, must accompany your DPP or DOCD:

(a) *Monitoring systems.* A description of any existing and planned monitoring systems that are measuring, or will measure, environmental conditions or will provide project-specific data or information on the impacts of your development and production activities.

(b) *Incidental takes.* If there is reason to believe that protected species may be incidentally taken by planned development and production activities, you must describe how you will monitor for incidental take of:

(1) Threatened and endangered species listed under the ESA and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take of marine mammals as may be necessary under the MMPA.

(c) *Flower Garden Banks National Marine Sanctuary (FGBNMS).* If you propose to conduct development and production activities within the protective zones of the FGBNMS, a description of your provisions for monitoring the impacts of an oil spill on the environmentally sensitive resources of the FGBNMS.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.253 What lease stipulations information must accompany the DPP or DOCD?

A description of the measures you took, or will take, to satisfy the conditions of lease stipulations related to your proposed development and production activities must accompany your DPP or DOCD.

§ 250.254 What mitigation measures information must accompany the DPP or DOCD?

(a) If you propose to use any measures beyond those required by the regulations in this part to minimize or mitigate environmental impacts from your proposed development and production activities, a description of the measures you will use must accompany your DPP or DOCD.

(b) If there is reason to believe that protected species may be incidentally taken by planned development and production activities, you must include mitigation measures designed to avoid or minimize that incidental take of:

(1) Threatened and endangered species listed under the ESA and

(2) Marine mammals, as appropriate, if you have not already received authorization for incidental take as may be necessary under the MMPA.

[72 FR 18585, Apr. 13, 2007]

§ 250.255 What decommissioning information must accompany the DPP or DOCD?

A brief description of how you intend to decommission your wells, platforms, pipelines, and other facilities, and clear your site(s) must accompany your DPP or DOCD.

§ 250.256 What related facilities and operations information must accompany the DPP or DOCD?

The following information regarding facilities and operations directly related to your proposed development and production activities must accompany your DPP or DOCD.

(a) *OCS facilities and operations.* A description and location of any of the following that directly relate to your proposed development and production activities:

(1) Drilling units;

(2) Production platforms;

(3) Right-of-way pipelines (including those that transport chemical products and produced water); and

(4) Other facilities and operations located on the OCS (regardless of ownership).

(b) *Transportation system.* A discussion of the transportation system that you will use to transport your production to shore, including:

(1) Routes of any new pipelines;

(2) Information concerning barges and shuttle tankers, including the storage capacity of the transport vessel(s), and the number of transfers that will take place per year;

(3) Information concerning any intermediate storage or processing facilities;

(4) An estimate of the quantities of oil, gas, or sulphur to be transported from your production facilities; and

(5) A description and location of the primary onshore terminal.

§ 250.257 What information on the support vessels, offshore vehicles, and aircraft you will use must accompany the DPP or DOCD?

The following information on the support vessels, offshore vehicles, and aircraft you will use must accompany your DPP or DOCD:

(a) *General.* A description of the crew boats, supply boats, anchor handling vessels, tug boats, barges, ice management vessels, other vessels, offshore vehicles, and aircraft you will use to support your development and production activities. The description of vessels and offshore vehicles must estimate the storage capacity of their fuel tanks and the frequency of their visits to the facilities you will use to conduct your proposed development and production activities.

(b) *Air emissions.* A table showing the source, composition, frequency, and duration of the air emissions likely to be generated by the support vessels, offshore vehicles, and aircraft you will use that will operate within 25 miles of the facilities you will use to conduct your proposed development and production activities.

(c) *Drilling fluids and chemical products transportation.* A description of the transportation method and quantities of drilling fluids and chemical products (see § 250.243(b) and (d)) you will transport from the onshore support facilities you will use to the facilities you will use to conduct your proposed development and production activities.

(d) *Solid and liquid wastes transportation.* A description of the transportation method and a brief description of the composition, quantities, and destination(s) of solid and liquid wastes (see § 250.248(a)) you will transport from the facilities you will use to conduct your proposed development and production activities.

(e) *Vicinity map.* A map showing the location of your proposed development and production activities relative to the shoreline. The map must depict the primary route(s) the support vessels and aircraft will use when traveling between the onshore support facilities you will use and the facilities you will use to conduct your proposed development and production activities.

§ 250.258 What information on the onshore support facilities you will use must accompany the DPP or DOCD?

The following information on the onshore support facilities you will use must accompany your DPP or DOCD:

(a) *General.* A description of the onshore facilities you will use to provide supply and service support for your proposed development and production activities (e.g., service bases and mud company docks).

(1) Indicate whether the onshore support facilities are existing, to be constructed, or to be expanded; and

(2) For DPPs only, provide a timetable for acquiring lands (including rights-of-way and easements) and constructing or expanding any of the onshore support facilities.

(b) *Air emissions.* A description of the source, composition, frequency, and duration of the air emissions (attributable to your proposed development and production activities) likely to be generated by the onshore support facilities you will use.

(c) *Unusual solid and liquid wastes.* A description of the quantity, composition, and method of disposal of any unusual solid and liquid wastes (attributable to your proposed development and production activities) likely to be generated by the onshore support facilities you will use. Unusual wastes are those wastes not specifically addressed in the relevant National Pollution Discharge Elimination System (NPDES) permit.

(d) *Waste disposal.* A description of the onshore facilities you will use to store and dispose of solid and liquid wastes generated by your proposed development and production activities (see § 250.248(a)) and the types and quantities of such wastes.

§ 250.259 What sulphur operations information must accompany the DPP or DOCD?

If you are proposing to conduct sulphur development and production activities, the following information must accompany your DPP or DOCD:

(a) *Bleedwater.* A discussion of the bleedwater that will be generated by your proposed sulphur activities, including the measures you will take to mitigate the potential toxic or thermal impacts on the environment caused by the discharge of bleedwater.

(b) *Subsidence.* An estimate of the degree of subsidence expected at various stages of your sulphur development and production activities, and a description of the measures you will take to mitigate the effects of subsidence on existing or potential oil and gas production, production platforms, and production facilities, and to protect the environment.

§ 250.260 What Coastal Zone Management Act (CZMA) information must accompany the DPP or DOCD?

The following CZMA information must accompany your DPP or DOCD:

(a) *Consistency certification.* A copy of your consistency certification under section 307(c)(3)(B) of the CZMA (16 U.S.C. 1456(c)(3)(B)) and 15 CFR 930.76(c) stating that the proposed development and production activities described in detail in this DPP or DOCD comply with (name of State(s)) approved coastal management program(s) and will be conducted in a manner that is consistent with such program(s); and

(b) *Other information.* ''Information'' as required by 15 CFR 930.76(a) and 15 CFR 930.58(a)(2)) and ''Analysis'' as required by 15 CFR 930.58(a)(3).

[70 FR 51501, Aug. 30, 2005, as amended at 73 FR 20171, Apr. 15, 2008]

§ 250.261 What environmental impact analysis (EIA) information must accompany the DPP or DOCD?

The following EIA information must accompany your DPP or DOCD:

(a) *General requirements.* Your EIA must:

(1) Assess the potential environmental impacts of your proposed development and production activities;

(2) Be project specific; and

(3) Be as detailed as necessary to assist the Regional Supervisor in complying with the NEPA of 1969 (42 U.S.C. 4321 *et seq.*) and other relevant Federal laws such as the ESA and the MMPA.

(b) *Resources, conditions, and activities.* Your EIA must describe those resources, conditions, and activities listed below that could be affected by your proposed development and production activities, or that could affect the construction and operation of facilities or structures or the activities proposed in your DPP or DOCD.

(1) Meteorology, oceanography, geology, and shallow geological or manmade hazards;

(2) Air and water quality;

(3) Benthic communities, marine mammals, sea turtles, coastal and marine birds, fish and shellfish, and plant life;

(4) Threatened or endangered species and their critical habitat;

(5) Sensitive biological resources or habitats such as essential fish habitat, refuges, preserves, special management areas identified in coastal management programs, sanctuaries, rookeries, and calving grounds;

(6) Archaeological resources;

(7) Socioeconomic resources (including the approximate number, timing, and duration of employment of persons engaged in onshore support and construction activities), population (including the approximate number of people and families added to local onshore areas), existing offshore and onshore infrastructure (including major sources of supplies, services, energy, and water), types of contractors or vendors that may place a demand on local goods and services, land use, subsistence resources and harvest practices, recreation, recreational and commercial fishing (including seasons, location, and type), minority and lower income groups, and CZMA programs;

(8) Coastal and marine uses such as military activities, shipping, and mineral exploration or development; and

(9) Other resources, conditions, and activities identified by the Regional Supervisor.

(c) *Environmental impacts.* Your EIA must:

(1) Analyze the potential direct and indirect impacts (including those from accidents, cooling water intake structures, and those identified in relevant ESA biological opinions such as, but not limited to, those from noise, vessel collisions, and marine trash and debris) that your proposed development and production activities will have on the identified resources, conditions, and activities;

(2) Describe the type, severity, and duration of these potential impacts and their biological, physical, and other consequences and implications;

(3) Describe potential measures to minimize or mitigate these potential impacts;

(4) Describe any alternatives to your proposed development and production activities that you considered while developing your DPP or DOCD, and compare the potential environmental impacts; and

(5) Summarize the information you incorporate by reference.

(d) *Consultation.* Your EIA must include a list of agencies and persons with whom you consulted, or with whom you will be consulting, regarding potential impacts associated with your proposed development and production activities.

(e) *References cited.* Your EIA must include a list of the references that you cite in the EIA.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.262 What administrative information must accompany the DPP or DOCD?

The following administrative information must accompany your DPP or DOCD:

(a) *Exempted information description (public information copies only).* A description of the general subject matter of the proprietary information that is included in the proprietary copies of your DPP or DOCD or its accompanying information.

(b) *Bibliography*. (1) If you reference a previously submitted EP, DPP, DOCD, study report, survey report, or other material in your DPP or DOCD or its accompanying information, a list of the referenced material; and

(2) The location(s) where the Regional Supervisor can inspect the cited referenced material if you have not submitted it.

REVIEW AND DECISION PROCESS FOR THE DPP OR DOCD

§ 250.266 After receiving the DPP or DOCD, what will MMS do?

(a) *Determine whether deemed submitted*. Within 25 working days after receiving your proposed DPP or DOCD and its accompanying information, the Regional Supervisor will deem your DPP or DOCD submitted if:

(1) The submitted information, including the information that must accompany the DPP or DOCD (refer to the list in § 250.242), fulfills requirements and is sufficiently accurate;

(2) You have provided all needed additional information (see § 250.201(b)); and

(3) You have provided the required number of copies (see § 250.206(a)).

(b) *Identify problems and deficiencies*. If the Regional Supervisor determines that you have not met one or more of the conditions in paragraph (a) of this section, the Regional Supervisor will notify you of the problem or deficiency within 25 working days after the Regional Supervisor receives your DPP or DOCD and its accompanying information. The Regional Supervisor will not deem your DPP or DOCD submitted until you have corrected all problems or deficiencies identified in the notice.

(c) *Deemed submitted notification*. The Regional Supervisor will notify you when your DPP or DOCD is deemed submitted.

§ 250.267 What actions will MMS take after the DPP or DOCD is deemed submitted?

(a) *State, local government, CZMA consistency, and other reviews*. Within 2 working days after the Regional Supervisor deems your DPP or DOCD submitted under § 250.266, the Regional Supervisor will use receipted mail or alternative method to send a public information copy of the DPP or DOCD and its accompanying information to the following:

(1) *The Governor of each affected State*. The Governor has 60 calendar days after receiving your deemed-submitted DPP or DOCD to submit comments and recommendations. The Regional Supervisor will not consider comments and recommendations received after the deadline.

(2) *The executive of any affected local government who requests a copy*. The executive of any affected local government has 60 calendar days after receipt of your deemed-submitted DPP or DOCD to submit comments and recommendations. The Regional Supervisor will not consider comments and recommendations received after the deadline. The executive of any affected local government must forward all comments and recommendations to the respective Governor before submitting them to the Regional Supervisor.

(3) *The CZMA agency of each affected State*. The CZMA consistency review period under section 307(c)(3)(B)(ii) of the CZMA (16 U.S.C.1456(c)(3)(B)(ii)) and 15 CFR 930.78 begins when the States CZMA agency receives a copy of your deemed-submitted DPP or DOCD, consistency certification, and required necessary data/information (see 15 CFR 930.77(a)(1)).

(b) *General public*. Within 2 working days after the Regional Supervisor deems your DPP or DOCD submitted under § 250.266, the Regional Supervisor will make a public information copy of the DPP or DOCD and its accompanying information available for review to any appropriate interstate regional entity and the public at the appropriate MMS Regional Public Information Office. Any interested Federal agency or person may submit comments and recommendations to the Regional Supervisor. Comments and recommendations must be received by the Regional Supervisor within 60 calendar days after the DPP or DOCD including its accompanying information is made available.

(c) *MMS compliance review.* The Regional Supervisor will review the development and production activities in your proposed DPP or DOCD to ensure that they conform to the performance standards in § 250.202.

(d) *Amendments.* During the review of your proposed DPP or DOCD, the Regional Supervisor may require you, or you may elect, to change your DPP or DOCD. If you elect to amend your DPP or DOCD, the Regional Supervisor may determine that your DPP or DOCD, as amended, is subject to the requirements of § 250.266.

§ 250.268 How does MMS respond to recommendations?

(a) *Governor.* The Regional Supervisor will accept those recommendations from the Governor that provide a reasonable balance between the national interest and the well-being of the citizens of each affected State. The Regional Supervisor will explain in writing to the Governor the reasons for rejecting any of his or her recommendations.

(b) *Local governments and the public.* The Regional Supervisor may accept recommendations from the executive of any affected local government or the public.

(c) *Availability.* The Regional Supervisor will make all comments and recommendations available to the public upon request.

§ 250.269 How will MMS evaluate the environmental impacts of the DPP or DOCD?

The Regional Supervisor will evaluate the environmental impacts of the activities described in your proposed DPP or DOCD and prepare environmental documentation under the National Environmental Policy Act (NEPA) (42 U.S.C.4321 *et seq.*) and the implementing regulations (40 CFR parts 1500 through 1508).

(a) *Environmental impact statement (EIS) declaration.* At least once in each OCS planning area (other than the Western and Central GOM Planning Areas), the Director will declare that the approval of a proposed DPP is a major Federal action, and MMS will prepare an EIS.

(b) *Leases or units in the vicinity.* Before or immediately after the Director determines that preparation of an EIS is required, the Regional Supervisor may require lessees and operators of leases or units in the vicinity of the proposed development and production activities for which DPPs have not been approved to submit information about preliminary plans for their leases or units.

(c) *Draft EIS.* The Regional Supervisor will send copies of the draft EIS to the Governor of each affected State and to the executive of each affected local government who requests a copy. Additionally, when MMS prepares a DPP EIS, and the Federally-approved CZMA program for an affected State requires a DPP NEPA document for use in determining consistency, the Regional Supervisor will forward a copy of the draft EIS to the State's CZMA agency. The Regional Supervisor will also make copies of the draft EIS available to any appropriate Federal agency, interstate regional entity, and the public.

§ 250.270 What decisions will MMS make on the DPP or DOCD and within what timeframe?

(a) *Timeframe.* The Regional Supervisor will act on your deemed-submitted DPP or DOCD as follows:

(1) The Regional Supervisor will make a decision within 60 calendar days after the latest of the day that:

(i) The comment period provided in § 250.267(a)(1), (a)(2), and (b) closes;

(ii) The final EIS for a DPP is released or adopted; or

(iii) The last amendment to your proposed DOCD is received by the Regional Supervisor.

(2) Notwithstanding paragraph (a)(1) of this section, MMS will not approve your DPP or DOCD until either:

(i) All affected States with approved CZMA programs concur, or have been conclusively presumed to concur, with your DPP or DOCD consistency certification under section 307(c)(3)(B)(i) and (ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(i) and (ii)); or

(ii) The Secretary of Commerce has made a finding authorized by section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C.

1456(c)(3)(B)(iii)) that each activity described in the DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of national security.

(b) *MMS decision.* By the deadline in paragraph (a) of this section, the Regional Supervisor will take one of the following actions:

The regional supervisor will . . .	If . . .	And then . . .
(1) Approve your DPP or DOCD.	It complies with all applicable requirements	The Regional Supervisor will notify you in writing of the decision and may require you to meet certain conditions, including those to provide monitoring information.
(2) Require you to modify your proposed DPP or DOCD.	It fails to make adequate provisions for safety, environmental protection, or conservation of natural resources or otherwise does not comply with the lease, the Act, the regulations prescribed under the Act, or other Federal laws.	The Regional Supervisor will notify you in writing of the decision and describe the modifications you must make to your proposed DPP or DOCD to ensure it complies with all applicable requirements.
(3) Disapprove your DPP or DOCD.	Any of the reasons in § 250.271 apply	(i) The Regional Supervisor will notify you in writing of the decision and describe the reason(s) for disapproving your DPP or DOCD; and (ii) MMS may cancel your lease and compensate you under 43 U.S.C. 1351(h)(2)(C) and the implementing regulations in §§ 250.183, 250.184, and 250.185 and 30 CFR 256.77.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.271 For what reasons will MMS disapprove the DPP or DOCD?

The Regional Supervisor will disapprove your proposed DPP or DOCD if one of the four reasons in this section applies:

(a) *Non-compliance.* The Regional Supervisor determines that you have failed to demonstrate that you can comply with the requirements of the Outer Continental Shelf Lands Act, as amended (Act), implementing regulations, or other applicable Federal laws.

(b) *No consistency concurrence.* (1) An affected State has not yet issued a final decision on your coastal zone consistency certification (see 15 CFR 930.78(a)); or

(2) An affected State objects to your coastal zone consistency certification, and the Secretary of Commerce, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)), has not found that each activity described in the DPP or DOCD is consistent with the objectives of the CZMA or is otherwise necessary in the interest of national security.

(3) If the Regional Supervisor disapproved your DPP or DOCD for the sole reason that an affected State either has not yet issued a final decision on, or has objected to, your coastal zone consistency certification (see paragraphs (b)(1) and (2) in this section), the Regional Supervisor will approve your DPP or DOCD upon receipt of concurrence by the affected State, at the time concurrence of the affected State is conclusively presumed, or when the Secretary of Commerce makes a finding authorized by section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(iii)) that each activity described in your DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of national security. In that event, you do not need to resubmit your DPP or DOCD for approval under § 250.273(b).

(c) *National security or defense conflicts.* Your proposed activities would threaten national security or defense.

(d) *Exceptional circumstances.* The Regional Supervisor determines because of exceptional geological conditions, exceptional resource values in the marine or coastal environment, or other exceptional circumstances that all of the following apply:

(1) Implementing your DPP or DOCD would 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 the marine, coastal, or human environment;

(2) The threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time; and

(3) The advantages of disapproving your DPP or DOCD outweigh the advantages of development and production.

§ 250.272 If a State objects to the DPP's or DOCD's coastal zone consistency certification, what can I do?

If an affected State objects to the coastal zone consistency certification accompanying your proposed or disapproved DPP or DOCD, you may do one of the following:

(a) *Amend or resubmit your DPP or DOCD.* Amend or resubmit your DPP or DOCD to accommodate the State's objection and submit the amendment or resubmittal to the Regional Supervisor for approval. The amendment or resubmittal needs to only address information related to the State's objections.

(b) *Appeal.* Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930, subpart H. The Secretary of Commerce will either:

(1) Grant your appeal by finding under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C.1456(c)(3)(B)(iii)) that each activity described in detail in your DPP or DOCD is consistent with the objectives of the CZMA, or is otherwise necessary in the interest of national security; or

(2) Deny your appeal, in which case you may amend or resubmit your DPP or DOCD, as described in paragraph (a) of this section.

(c) *Withdraw your DPP or DOCD.* Withdraw your DPP or DOCD if you decide not to conduct your proposed development and production activities.

§ 250.273 How do I submit a modified DPP or DOCD or resubmit a disapproved DPP or DOCD?

(a) *Modified DPP or DOCD.* If the Regional Supervisor requires you to modify your proposed DPP or DOCD under § 250.270(b)(2), you must submit the modification(s) to the Regional Supervisor in the same manner as for a new DPP or DOCD. You need submit only information related to the proposed modification(s).

(b) *Resubmitted DPP or DOCD.* If the Regional Supervisor disapproves your DPP or DOCD under § 250.270(b)(3), and except as provided in § 250.271(b)(3), you may resubmit the disapproved DPP or DOCD if there is a change in the conditions that were the basis of its disapproval.

(c) *MMS review and timeframe.* The Regional Supervisor will use the performance standards in § 250.202 to either approve, require you to further modify, or disapprove your modified or resubmitted DPP or DOCD. The Regional Supervisor will make a decision within 60 calendar days after the Regional Supervisor deems your modified or resubmitted DPP or DOCD to be submitted, or receives the last amendment to your modified or resubmitted DPP or DOCD, whichever occurs later.

POST-APPROVAL REQUIREMENTS FOR THE EP, DPP, AND DOCD

§ 250.280 How must I conduct activities under the approved EP, DPP, or DOCD?

(a) *Compliance.* You must conduct all of your lease and unit activities according to your approved EP, DPP, or DOCD and any approval conditions. If you fail to comply with your approved EP, DPP, or DOCD:

(1) You may be subject to MMS enforcement action, including civil penalties; and

(2) The lease(s) involved in your EP, DPP, or DOCD may be forfeited or cancelled under 43 U.S.C. 1334(c) or (d). If this happens, you will not be entitled to compensation under § 250.185(b) and 30 CFR 256.77.

(b) *Emergencies.* Nothing in this subpart or in your approved EP, DPP, or DOCD relieves you of, or limits your responsibility to take appropriate measures to meet emergency situations. In an emergency situation, the Regional Supervisor may approve or require departures from your approved EP, DPP, or DOCD.

§ 250.281 What must I do to conduct activities under the approved EP, DPP, or DOCD?

(a) *Approvals and permits.* Before you conduct activities under your approved

EP, DPP, or DOCD you must obtain the following approvals and or permits, as applicable, from the District Manager or Regional Supervisor:

(1) Approval of applications for permits to drill (APDs) (see § 250.410);

(2) Approval of production safety systems (see § 250.800);

(3) Approval of new platforms and other structures (or major modifications to platforms and other structures) (see § 250.905);

(4) Approval of applications to install lease term pipelines (see § 250.1007); and

(5) Other permits, as required by applicable law.

(b) *Conformance.* The activities proposed in these applications and permits must conform to the activities described in detail in your approved EP, DPP, or DOCD.

(c) *Separate State CZMA consistency review.* APDs, and other applications for licenses, approvals, or permits to conduct activities under your approved EP, DPP, or DOCD including those identified in paragraph (a) of this section, are not subject to separate State CZMA consistency review.

(d) *Approval restrictions for permits for activities conducted under EPs.* The District Manager or Regional Supervisor will not approve any APDs or other applications for licenses, approvals, or permits under your approved EP until either:

(1) All affected States with approved coastal zone management programs concur, or are conclusively presumed to concur, with the coastal zone consistency certification accompanying your EP under section 307(c)(3)(B)(i) and (ii) of the CZMA (16 U.S.C. 1456(c)(3)(B)(i) and (ii)); or

(2) The Secretary of Commerce finds, under section 307(c)(3)(B)(iii) of the CZMA (16 U.S.C.1456(c)(3)(B)(iii)) that each activity covered by the EP is consistent with the objectives of the CZMA or is otherwise necessary in the interest of national security;

(3) If an affected State objects to the coastal zone consistency certification accompanying your approved EP after MMS has approved your EP, you may either:

(i) Revise your EP to accommodate the State's objection and submit the revision to the Regional Supervisor for approval; or

(ii) Appeal the State's objection to the Secretary of Commerce using the procedures in 15 CFR part 930 subpart H. The Secretary of Commerce will either:

(A) Grant your appeal by making the finding described in paragraph (d)(2) of this section; or

(B) Deny your appeal, in which case you may revise your EP as described in paragraph (d)(3)(i) of this section.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 25200, May 4, 2007]

§ 250.282 Do I have to conduct post-approval monitoring?

After approving your EP, DPP, or DOCD, the Regional Supervisor may direct you to conduct monitoring programs, including monitoring in accordance with the ESA and the MMPA. You must retain copies of all monitoring data obtained or derived from your monitoring programs and make them available to the MMS upon request. The Regional Supervisor may require you to:

(a) *Monitoring plans.* Submit monitoring plans for approval before you begin the work; and

(b) *Monitoring reports.* Prepare and submit reports that summarize and analyze data and information obtained or derived from your monitoring programs. The Regional Supervisor will specify requirements for preparing and submitting these reports.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 18585, Apr. 13, 2007]

§ 250.283 When must I revise or supplement the approved EP, DPP, or DOCD?

(a) *Revised OCS plans.* You must revise your approved EP, DPP, or DOCD when you propose to:

(1) Change the type of drilling rig (e.g., jack-up, platform rig, barge, submersible, semisubmersible, or drillship), production facility (e.g., caisson, fixed platform with piles, tension leg platform), or transportation mode (e.g., pipeline, barge);

(2) Change the surface location of a well or production platform by a distance more than that specified by the Regional Supervisor;

(3) Change the type of production or significantly increase the volume of production or storage capacity;

(4) Increase the emissions of an air pollutant to an amount that exceeds the amount specified in your approved EP, DPP, or DOCD;

(5) Significantly increase the amount of solid or liquid wastes to be handled or discharged;

(6) Request a new H2S area classification, or increase the concentration of H2S to a concentration greater than that specified by the Regional Supervisor;

(7) Change the location of your onshore support base either from one State to another or to a new base or a base requiring expansion; or

(8) Change any other activity specified by the Regional Supervisor.

(b) *Supplemental OCS plans.* You must supplement your approved EP, DPP, or DOCD when you propose to conduct activities on your lease(s) or unit that require approval of a license or permit which is not described in your approved EP, DPP, or DOCD. These types of changes are called supplemental OCS plans.

§ 250.284 How will MMS require revisions to the approved EP, DPP, or DOCD?

(a) *Periodic review.* The Regional Supervisor will periodically review the activities you conduct under your approved EP, DPP, or DOCD and may require you to submit updated information on your activities. The frequency and extent of this review will be based on the significance of any changes in available information and onshore or offshore conditions affecting, or affected by, the activities in your approved EP, DPP, or DOCD.

(b) *Results of review.* The Regional Supervisor may require you to revise your approved EP, DPP, or DOCD based on this review. In such cases, the Regional Supervisor will inform you of the reasons for the decision.

§ 250.285 How do I submit revised and supplemental EPs, DPPs, and DOCDs?

(a) *Submittal.* You must submit to the Regional Supervisor any revisions and supplements to approved EPs, DPPs, or DOCDs for approval, whether you initiate them or the Regional Supervisor orders them.

(b) *Information.* Revised and supplemental EPs, DPPs, and DOCDs need include only information related to or affected by the proposed changes, including information on changes in expected environmental impacts.

(c) *Procedures.* All supplemental EPs, DPPs, and DOCDs, and those revised EPs, DPPs, and DOCDs that the Regional Supervisor determines are likely to result in a significant change in the impacts previously identified and evaluated, are subject to all of the procedures under § 250.231 through § 250.235 for EPs and § 250.266 through § 250.273 for DPPs and DOCDs.

[70 FR 51501, Aug. 30, 2005, as amended at 72 FR 25201, May 4, 2007]

DEEPWATER OPERATIONS PLANS (DWOP)

§ 250.286 What is a DWOP?

(a) A DWOP is a plan that provides sufficient information for MMS to review a deepwater development project, and any other project that uses non-conventional production or completion technology, from a total system approach. The DWOP does not replace, but supplements other submittals required by the regulations such as Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents. MMS will use the information in your DWOP to determine whether the project will be developed in an acceptable manner, particularly with respect to operational safety and environmental protection issues involved with non-conventional production or completion technology.

(b) The DWOP process consists of two parts: a Conceptual Plan and the DWOP. Section 250.289 prescribes what the Conceptual Plan must contain, and § 250.292 prescribes what the DWOP must contain.

§ 250.287 For what development projects must I submit a DWOP?

You must submit a DWOP for each development project in which you will use non-conventional production or completion technology, regardless of water depth. If you are unsure whether

MMS considers the technology of your project non-conventional, you must contact the Regional Supervisor for guidance.

§ 250.288 When and how must I submit the Conceptual Plan?

You must submit four copies, or one hard copy and one electronic version, of the Conceptual Plan to the Regional Director after you have decided on the general concept(s) for development and before you begin engineering design of the well safety control system or subsea production systems to be used after well completion.

§ 250.289 What must the Conceptual Plan contain?

In the Conceptual Plan, you must explain the general design basis and philosophy that you will use to develop the field. You must include the following information:

(a) An overview of the development concept(s);

(b) A well location plat;

(c) The system control type (*i.e.*, direct hydraulic or electro-hydraulic); and

(d) The distance from each of the wells to the host platform.

§ 250.290 What operations require approval of the Conceptual Plan?

You may not complete any production well or install the subsea wellhead and well safety control system (often called the tree) before MMS has approved the Conceptual Plan.

§ 250.291 When and how must I submit the DWOP?

You must submit four copies, or one hard copy and one electronic version, of the DWOP to the Regional Director after you have substantially completed safety system design and before you begin to procure or fabricate the safety and operational systems (other than the tree), production platforms, pipelines, or other parts of the production system.

§ 250.292 What must the DWOP contain?

You must include the following information in your DWOP:

(a) A description and schematic of the typical wellbore, casing, and completion;

(b) Structural design, fabrication, and installation information for each surface system, including host facilities;

(c) Design, fabrication, and installation information on the mooring systems for each surface system;

(d) Information on any active stationkeeping system(s) involving thrusters or other means of propulsion used with a surface system;

(e) Information concerning the drilling and completion systems;

(f) Design and fabrication information for each riser system (e.g., drilling, workover, production, and injection);

(g) Pipeline information;

(h) Information about the design, fabrication, and operation of an offtake system for transferring produced hydrocarbons to a transport vessel;

(i) Information about subsea wells and associated systems that constitute all or part of a single project development covered by the DWOP;

(j) Flow schematics and Safety Analysis Function Evaluation (SAFE) charts (API RP 14C, subsection 4.3c, incorporated by reference in § 250.198) of the production system from the Surface Controlled Subsurface Safety Valve (SCSSV) downstream to the first item of separation equipment;

(k) A description of the surface/subsea safety system and emergency support systems to include a table that depicts what valves will close, at what times, and for what events or reasons;

(l) A general description of the operating procedures, including a table summarizing the curtailment of production and offloading based on operational considerations;

(m) A description of the facility installation and commissioning procedure;

(n) A discussion of any new technology that affects hydrocarbon recovery systems;

(o) A list of any alternate compliance procedures or departures for which you anticipate requesting approval; and

(p) Payment of the service fee listed in § 250.125.

[70 FR 51501, Aug. 30, 2005, as amended at 71 FR 40911, July 19, 2006]

§ 250.293 What operations require approval of the DWOP?

You may not begin production until MMS approves your DWOP.

§ 250.294 May I combine the Conceptual Plan and the DWOP?

If your development project meets the following criteria, you may submit a combined Conceptual Plan/DWOP on or before the deadline for submitting the Conceptual Plan.

(a) The project is located in water depths of less than 400 meters (1,312 feet); and

(b) The project is similar to projects involving non-conventional production or completion technology for which you have obtained approval previously.

§ 250.295 When must I revise my DWOP?

You must revise either the Conceptual Plan or your DWOP to reflect changes in your development project that materially alter the facilities, equipment, and systems described in your plan. You must submit the revision within 60 days after any material change to the information required for that part of your plan.

CONSERVATION INFORMATION DOCUMENTS (CID)

§ 250.296 When and how must I submit a CID or a revision to a CID?

(a) You must submit one original and two copies of a CID to the appropriate OCS Region at the same time you first submit your DOCD or DPP for any development of a lease or leases located in water depths greater than 400 meters (1,312 feet). You must also submit a CID for a Supplemental DOCD or DPP when requested by the Regional Supervisor. The submission of your CID must be accompanied by payment of the service fee listed in § 250.125.

(b) If you decide not to develop a reservoir you committed to develop in your CID, you must submit one original and two copies of a revision to the CID to the appropriate OCS Region. The revision to the CID must be submitted within 14 calendar days after making your decision not to develop the reservoir and before the reservoir is bypassed. The Regional Supervisor will approve or disapprove any such revision to the original CID. If the Regional Supervisor disapproves the revision, you must develop the reservoir as described in the original CID.

[70 FR 51501, Aug. 30, 2005, as amended at 71 FR 40911, July 19, 2006]

§ 250.297 What information must a CID contain?

(a) You must base the CID on wells drilled before your CID submittal, that define the extent of the reservoirs. You must notify MMS of any well that is drilled to total depth during the CID evaluation period and you may be required to update your CID.

(b) You must include all of the following information if available. Information must be provided for each hydrocarbon-bearing reservoir that is penetrated by a well that would meet the producibility requirements of § 250.115 or § 250.116:

(1) General discussion of the overall development of the reservoir;

(2) Summary spreadsheets of well log data and reservoir parameters (*i.e.*, sand tops and bases, fluid contacts, net pay, porosity, water saturations, pressures, formation volume factor);

(3) Appropriate well logs, including digital well log (*i.e.*, gamma ray, resistivity, neutron, density, sonic, caliper curves) curves in an acceptable digital format;

(4) Sidewall core/whole core and pressure-volume-temperature analysis;

(5) Structure maps, with the existing and proposed penetration points and subsea depths for all wells penetrating the reservoirs, fluid contacts (or the lowest or highest known levels in the absence of actual contacts), reservoir boundaries, and the scale of the map;

(6) Interpreted structural cross sections and corresponding interpreted seismic lines or block diagrams, as necessary, that include all current wellbores and planned wellbores on the leases or units to be developed, the reservoir boundaries, fluid contacts, depth scale, stratigraphic positions, and relative biostratigraphic ages;

(7) Isopach maps of each reservoir showing the net feet of pay for each well within the reservoir identified at the penetration point, along with the well name, labeled contours, and scale;

(8) Estimates of original oil and gas in-place and anticipated recoverable oil and gas reserves, all reservoir parameters, and risk factors and assumptions;

(9) Plat map at the same scale as the structure maps with existing and proposed well paths, as well as existing and proposed penetrations;

(10) Wellbore schematics indicating proposed perforations;

(11) Proposed wellbore utility chart showing all existing and proposed wells, with proposed completion intervals indicated for each borehole;

(12) Appropriate pressure data, specified by date, and whether estimated or measured;

(13) Description of reservoir development strategies;

(14) Description of the enhanced recovery practices you will use or, if you do not plan to use such practices, an explanation of the methods you considered and reasons you do not intend to use them;

(15) For each reservoir you do not intend to develop:

(i) A statement explaining the reason(s) you will not develop the reservoir, and

(ii) Economic justification, including costs, recoverable reserve estimate, production profiles, and pricing assumptions; and

(16) Any other appropriate data you used in performing your reservoir evaluations and preparing your reservoir development strategies.

§ 250.298 How long will MMS take to evaluate and make a decision on the CID?

(a) The Regional Supervisor will make a decision within 150 calendar days of receiving your CID. If MMS does not act within 150 calendar days, your CID is considered approved.

(b) MMS may suspend the 150-calendar-day evaluation period if there is missing, inconclusive, or inaccurate data, or when a well reaches total depth during the evaluation period. MMS may also suspend the evaluation period when a well penetrating a hydrocarbon-bearing structure reaches total depth during the evaluation period and the data from that well is needed for the CID. You will receive written notification from the Regional Supervisor describing the additional information that is needed, and the evaluation period will resume once MMS receives the requested information.

(c) The Regional Supervisor will approve or deny your CID request based on your commitment to develop economically producible reservoirs according to sound conservation, engineering, and economic practices.

§ 250.299 What operations require approval of the CID?

You may not begin production before you receive MMS approval of the CID.

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 Manager 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 Manager.

(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 Manager may restrict the rate of drilling fluid discharges or prescribe alternative discharge methods. The District Manager 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 Manager.

(2) Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Manager.

(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 Manager.

[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 Manager 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 § 250.218 or § 250.249 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 § 250.249(a) or § 250.218(a) of this part and compare these emissions to the emission exemption amount "E" for each air pollutant calculated using the following formulas: $E=3400D^{2/3}$ for carbon monoxide (CO); and $E=33.3D$ for total suspended particulates (TSP), sulphur dioxide (SO_2), nitrogen oxides (NO_X), and VOC (where E is the emission exemption amount expressed in tons per year, and D is the distance of the proposed facility from the closest onshore area of a State expressed in statute miles). If the amount of these projected emissions is less than or equal to the emission exemption amount "E" for the air pollutant, the facility is exempt from further air quality review required under paragraphs (e) through (i) of this section.

(e) *Significance levels.* For a facility not exempt under paragraph (d) of this section for air pollutants other than VOC, the lessee shall use an approved air quality model to determine whether the projected emissions of those air pollutants from the facility result in an onshore ambient air concentration above the following significance levels:

SIGNIFICANCE LEVELS: AIR POLLUTANT CONCENTRATIONS ($\mu G/M^3$)

Air pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO_2	1	5	......	25	....
TSP	1	5	......	....	....
NO_2	1	....	......	....	....
CO	....	....	500	....	2,000

(f) *Significance determinations.* (1) The projected emissions of any air pollutant other than VOC from any facility which result in an onshore ambient air concentration above the significance level determined under paragraph (e) of this section for that air pollutant, shall be deemed to significantly affect the air quality of the onshore area for that air pollutant.

(2) The projected emissions of VOC from any facility which is not exempt under paragraph (d) of this section for that air pollutant shall be deemed to significantly affect the air quality of the onshore area for VOC.

(g) *Controls required.* (1) The projected emissions of any air pollutant other than VOC from any facility, except a temporary facility, which significantly affect the quality of a nonattainment area, shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(2) The projected emissions of any air pollutant other than VOC from any facility which significantly affect the air quality of an attainment or unclassifiable area shall be reduced through the application of BACT.

(i) Except for temporary facilities, the lessee also shall use an approved air quality model to determine whether the emissions of TSP or SO_2 that remain after the application of BACT cause the following maximum allowable increases over the baseline concentrations established in 40 CFR 52.21 to be exceeded in the attainment or unclassifiable area:

MAXIMUM ALLOWABLE CONCENTRATION INCREASES (μG/M3)

Air pollutant	Averaging times		
	Annual mean [1]	24-hour maximum	3-hour maximum
Class I:			
TSP	5	10	....
SO_2	2	5	25
Class II:			
TSP	19	37	....
SO_2	20	91	512
Class III:			
TSP	37	75	....
SO_2	40	182	700

[1] For TSP—geometric; For SO_2—arithmetic.

No concentration of an air pollutant shall exceed the concentration permitted under the national secondary ambient air quality standard or the concentration permitted under the national primary air quality standard, whichever concentration is lowest for the air pollutant for the period of exposure. For any period other than the annual period, the applicable maximum allowable increase may be exceeded during one such period per year at any one onshore location.

(ii) If the maximum allowable increases are exceeded, the lessee shall apply whatever additional emission controls are necessary to reduce or offset the remaining emissions of TSP or SO_2 so that concentrations in the onshore ambient air of an attainment or unclassifiable area do not exceed the maximum allowable increases.

(3)(i) The projected emissions of VOC from any facility, except a temporary facility, which significantly affect the onshore air quality of a nonattainment area shall be fully reduced. This shall be done through the application of BACT and, if additional reductions are necessary, through the application of additional emission controls or through the acquisition of offshore or onshore offsets.

(ii) The projected emissions of VOC from any facility which significantly affect the onshore air quality of an attainment area shall be reduced through the application of BACT.

(4)(i) If projected emissions from a facility significantly affect the onshore air quality of both a nonattainment and an attainment or unclassifiable area, the regulatory requirements applicable to projected emissions significantly affecting a nonattainment area shall apply.

(ii) If projected emissions from a facility significantly affect the onshore air quality of more than one class of attainment area, the lessee must reduce projected emissions to meet the maximum allowable increases specified for each class in paragraph (g)(2)(i) of this section.

(h) *Controls required on temporary facilities.* The lessee shall apply BACT to reduce projected emissions of any air pollutant from a temporary facility which significantly affect the air quality of an onshore area of a State.

(i) *Emission offsets.* When emission offsets are to be obtained, the lessee must demonstrate that the offsets are equivalent in nature and quantity to the projected emissions that must be reduced after the application of BACT; a binding commitment exists between the lessee and the owner or owners of the source or sources; the appropriate air quality control jurisdiction has been notified of the need to revise the State Implementation Plan to include the information regarding the offsets; and the required offsets come from sources which affect the air quality of the area significantly affected by the lessee's offshore operations.

(j) *Review of facilities with emissions below the exemption amount.* If, during the review of a new, modified, or revised Exploration Plan or Development and Production Plan, the Regional Supervisor determines or an affected State submits information to the Regional Supervisor which demonstrates, in the judgment of the Regional Supervisor, that projected emissions from an otherwise exempt facility will, either individually or in combination with other facilities in the area, significantly affect the air quality of an onshore area, then the Regional Supervisor shall require the lessee to submit additional information to determine whether emission control measures are necessary. The lessee shall be given the opportunity to present information to the Regional Supervisor which demonstrates that the exempt facility is not significantly affecting the air quality of an onshore area of the State.

(k) *Emission monitoring requirements.* The lessee shall monitor, in a manner approved or prescribed by the Regional Supervisor, emissions from the facility. The lessee shall submit this information monthly in a manner and form approved or prescribed by the Regional Supervisor.

(l) *Collection of meteorological data.* The Regional Supervisor may require the lessee to collect, for a period of time and in a manner approved or prescribed by the Regional Supervisor, and submit meteorological data from a facility.

[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; 70 FR 51518, Aug. 30, 2005]

§ 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 § 250.218 or 250.249 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 § 250.218(a) or 250.249(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; 70 FR 51519, Aug. 30, 2005]

Subpart D—Oil and Gas Drilling Operations

GENERAL REQUIREMENTS

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.402 When and how must I secure a well?

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

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

(1) Evacuation of the drilling crew;

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.403 What drilling unit movements must I report?

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

(1) The arrival of an MODU on location;

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.404 What are the requirements for the crown block?

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

(1) Starts a larger engine;

(2) Powers a firewater pump;

(3) Powers an emergency generator;

(4) Powers a BOP accumulator system;

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

(6) Powers temporary equipment on a nonproducing platform;

(7) Powers an escape capsule; or

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

[68 FR 8423, Feb. 20, 2003]

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

You may use alternative procedures or equipment during drilling operations after receiving approval from the District Manager. You must identify and discuss your proposed alternative procedures or equipment in your Application for Permit to Drill (APD) (Form MMS–123) (see § 250.414(h)). Procedures for obtaining approval are described in section 250.141 of this part.

[68 FR 8423, Feb. 20, 2003, as amended at 72 FR 25201, May 4, 2007]

§ 250.409 May I obtain departures from these drilling requirements?

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

[68 FR 8423, Feb. 20, 2003]

APPLYING FOR A PERMIT TO DRILL

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

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

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

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

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

(d) Submit the following to the District Manager:

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

(2) A separate public information copy of forms MMS–123 and MMS–123S that meets the requirements of § 250.186; and

(3) Payment of the service fee listed in § 250.125.

[68 FR 8423, Feb. 20, 2003, as amended at 71 FR 40911, July 19, 2006; 72 FR 25201, May 4, 2007]

§ 250.411 What information must I submit with my application?

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

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well.	§ 250.412
(b) Design criteria used for the proposed well.	§ 250.413
(c) Drilling prognosis	§ 250.414
(d) Casing and cementing programs	§ 250.415
(e) Diverter and BOP systems descriptions	§ 250.416
(f) Requirements for using an MODU	§ 250.417
(g) Additional information	§ 250.418

[68 FR 8423, Feb. 20, 2003]

§ 250.412 What requirements must the location plat meet?

The location plat must:

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

Your description of well drilling design criteria must address:

(a) Pore pressures;

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

(c) Potential lost circulation zones;

(d) Drilling fluid weights;

(e) Casing setting depths;

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

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

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

(i) Permafrost zones, if applicable.

[68 FR 8423, Feb. 20, 2003]

§ 250.414 What must my drilling prognosis include?

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

(a) Projected plans for coring at specified depths;

(b) Projected plans for logging;

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

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

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

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

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

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

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

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

(e) A statement of how you evaluated the best practices included in API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deep Water Wells (incorporated by reference as specified in § 250.198), if you drill a well in water depths greater than 500 feet and are in either of the following two areas:

(1) An ''area with an unknown shallow water flow potential'' is a zone or geologic formation where neither the presence nor absence of potential for a shallow water flow has been confirmed.

(2) An ''area known to contain a shallow water flow hazard'' is a zone or geologic formation for which drilling has confirmed the presence of shallow water flow.

[68 FR 8423, Feb. 20, 2003, as amended at 72 FR 8903, Feb. 28, 2007]

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

You must include in the diverter and BOP descriptions:

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

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the annular BOP installed in the diverter housing;

(2) Spool outlet internal diameter(s);

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

(c) *Frontier areas.* (1) If the design of the drilling unit you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the unit's design. If required, you must obtain the third-party review according to § 250.915 through § 250.918. You may submit this information before submitting an APD.

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003, as amended at 72 FR 25201, May 4, 2007]

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

You must include the following with the APD:

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

Casing and Cementing Requirements

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

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

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

(1) Properly control formation pressures and fluids;

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

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

(4) Protect freshwater aquifers from contamination; and

(5) Support unconsolidated sediments.

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

Casing type	Casing requirements	Cementing requirements
(a) Drive or Structural	Set by driving, jetting, or drilling to the minimum depth as approved or prescribed by the District Manager.	If you drilled a portion of this hole, you must use enough cement to fill the annular space back to the mudline.
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a glory hole, you must discuss the cement fill level with the District Manager.
(c) Surface	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths.	Use enough cement to fill the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.
(d) Intermediate	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well. As a minimum, you must cement the annular space 500 feet above the casing shoe and 500 feet above each zone to be isolated.
(e) Production	Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions.	Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe. As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe..	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.

[68 FR 8423, Feb. 20, 2003]

§ 250.422 When may I resume drilling after cementing?

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.423 What are the requirements for pressure testing casing?

The table in this section describes the minimum test pressures for each string of casing. You may not resume drilling or other down-hole operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test or if there is another indication of a leak, you must re-cement, repair the casing, or run additional casing to provide a proper seal. The District Manager may approve or require other casing test pressures.

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

[68 FR 8423, Feb. 20, 2003]

§ 250.424 What are the requirements for prolonged drilling operations?

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

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

(1) Caliper or pressure test the casing; and

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.425 What are the requirements for pressure testing liners?

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

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

(c) You may not resume drilling or other down-hole operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test or if there is another indication of a leak, you must re-cement, repair the liner, or run additional casing/liner to provide a proper seal.

[68 FR 8423, Feb. 20, 2003]

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.427 What are the requirements for pressure integrity tests?

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

[68 FR 8423, Feb. 20, 2003]

DIVERTER SYSTEM REQUIREMENTS

§ 250.430 When must I install a diverter system?

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

[68 FR 8423, Feb. 20, 2003]

§ 250.431 What are the diverter design and installation requirements?

You must design and install your diverter system to:

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.433 What are the diverter actuation and testing requirements?

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

BLOWOUT PREVENTER (BOP) SYSTEM REQUIREMENTS

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

(b) Your surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing the drill pipe that is in the hole.

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

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

[68 FR 8423, Feb. 20, 2003, as amended at 74 FR 46908, Sept. 14, 2009]

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.444 What are the choke manifold requirements?

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.446 What are the BOP maintenance and inspection requirements?

(a) You must maintain your BOP system to ensure that the equipment functions properly. BOP maintenance must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198).

(b) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system and marine riser at least once every 3 days if weather and sea conditions permit. You may use television cameras to inspect subsea equipment.

[68 FR 8423, Feb. 20, 2003]

§ 250.447 When must I pressure test the BOP system?

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

(a) When installed;

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.448 What are the BOP pressure tests requirements?

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.449 What additional BOP testing requirements must I meet?

You must meet the following additional BOP testing requirements:

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

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

(c) Alternate tests between control stations and pods;

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.450 What are the recordkeeping requirements for BOP tests?

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

(a) Record BOP test pressures on pressure charts;

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

[68 FR 8423, Feb. 20, 2003]

DRILLING FLUID REQUIREMENTS

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

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

[68 FR 8423, Feb. 20, 2003]

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

Your drilling fluid program must include the following safe practices:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003; 68 FR 14274, Mar. 24, 2003]

§ 250.457 What equipment is required to monitor drilling fluids?

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.458 What quantities of drilling fluids are required?

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

OTHER DRILLING REQUIREMENTS

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

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

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

(2) Estimated flow rates and cumulative volumes;

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

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

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

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

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

(8) Description of the test procedures.

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

(iii) When you reach total depth.

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

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

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

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

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

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.463 Who establishes field drilling rules?

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

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

[68 FR 8423, Feb. 20, 2003]

Applying for a Permit To Modify and Well Records

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

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

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

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

(1) Your APM (Form MMS–124) must contain a detailed statement of the proposed work that would materially change from the approved APD. The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;

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

(3) Within 30 days after completing this work, you must submit form MMS–124 with detailed information about the work to the District Manager, unless you have already provided

sufficient information in a Well Activity Report, form MMS–133 (§ 250.468(b)).

[68 FR 8423, Feb. 20, 2003, as amended at 71 FR 40911, July 19, 2006]

§ 250.466 What records must I keep?

You must keep complete, legible, and accurate records for each well. You must keep drilling records onsite while drilling activities continue. After completion of drilling activities, you must keep all drilling and other well records for the time periods shown in § 250.467. You may keep these records at a location of your choice. The records must contain complete information on all of the following:

(a) Well operations;

(b) Descriptions of formations penetrated;

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

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

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

(f) Any significant malfunction or problem; and

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

[68 FR 8423, Feb. 20, 2003, as amended at 72 FR 25201, May 4, 2007]

§ 250.467 How long must I keep records?

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

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

[68 FR 8423, Feb. 20, 2003]

§ 250.468 What well records am I required to submit?

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

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

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

[68 FR 8423, Feb. 20, 2003]

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

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

(a) Well records as specified in § 250.466;

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

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

(d) Other reports and records of operations.

[68 FR 8423, Feb. 20, 2003]

HYDROGEN SULFIDE

§ 250.490 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 Manager for approval. Do not begin operations before the District Manager 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, American National Standard for Respiratory Protection (incorporated by reference as specified in § 250.198);

(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 Manager 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 Manager 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 Manager 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 Manager 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 Manager 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 in conformance with ANSI Z88.2 (incorporated by reference as specified in § 250.198).

(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 Manager 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 OCS facility. You must report these gas releases to the District Manager immediately by oral communication, with a written follow-up report within 15 days, pursuant to §§ 250.188 through 250.190.

(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) of this section. You must also follow the requirements of § 250.1164. 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 Manager. 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 in conformance with NACE Standard MR0175–03 (incorporated by reference as specified in § 250.198).

(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 nonrestricted 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 Manager.

(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 Manager an analysis of the anticipated H_2S content of the water at the final treatment vessel and at the discharge point. The District Manager may require that the water be treated for removal of H_2S. The District Manager 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. Redesignated and amended at 68 FR 8423, 8434, Feb. 20, 2003; 71 FR 19645, Apr. 17, 2006; 72 FR 12096, Mar. 15, 2007; 72 FR 25201, May 4, 2007; 75 FR 20289, Apr. 19, 2010]

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 Manager. 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 §250.490 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 §250.490 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; 68 FR 8434, Feb. 20, 2003]

§ 250.505 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Manager 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.

Diesel engine air intakes must be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic-shutdown devices.

[74 FR 46908, Sept. 14, 2009]

§ 250.511 Traveling-block safety device.

All units being used for well-completion operations that have both a traveling block and a crown block must be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device must be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check must be entered in the operations log.

[74 FR 46908, Sept. 14, 2009]

§ 250.512 Field well-completion rules.

When geological and engineering information available in a field enables the District Manager to determine specific operating requirements, field well-completion rules may be established on the District Manager'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 Manager or upon the request of a lessee.

§ 250.513 Approval and reporting of well-completion operations.

(a) No well-completion operation may begin until the lessee receives written approval from the District Manager. If completion is planned and the data are available at the time you submit the Application for Permit to Drill and Supplemental APD Information Sheet (Forms MMS–123 and MMS–123S), you may request approval for a well-completion on those forms (see §§ 250.410 through 250.418 of this part). If the District Manager has not approved the completion or if the completion objective or plans have significantly changed, you must submit an Application for Permit to Modify (Form MMS–124) for approval of such operations.

(b) You must submit the following with Form MMS–124 (or with Form MMS–123; Form MMS–123S):

(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;

(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 § 250.490 of this part; and

(5) Payment of the service fee listed in § 250.125.

(c) Within 30 days after completion, you must submit to the District Manager an End of Operations Report (Form MMS–125), including a schematic of the tubing and subsurface equipment.

(d) You must submit public information copies of Form MMS–125 according to § 250.186.

[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; 68 FR 8434, Feb. 20, 2003; 71 FR 19646, Apr. 17, 2006; 71 FR 40911, July 19, 2006; 72 FR 25201, May 4, 2007]

§ 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 must meet the appropriate standards from the following table:

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

(c) The BOP systems for well completions must be equipped with the following:

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

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

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

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

(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, as amended at 68 FR 8434, Feb. 20, 2003; 74 FR 46908, Sept. 14, 2009]

§ 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 Manager 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 Manager 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 Manager may approve alternate methods and frequencies to inspect a marine riser.

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

(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 Manager.

(j) *Alternate methods.* The District Manager 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 Manager.

(c) When the tree is installed, you must equip wells to monitor for casing pressure according to the following chart:

If you have * * *	you must equip * * *	so you can monitor * * *
(1) fixed platform wells,	the wellhead,	all annuli (A, B, C, D, etc., annuli).
(2) subsea wells,	the tubing head,	the production casing annulus (A annulus).
(3) hybrid* wells,	the surface wellhead,	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

* Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(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; 75 FR 23584, May 4, 2010]

CASING PRESSURE MANAGEMENT

SOURCE: 75 FR 23584, May 4, 2010, unless otherwise noted.

§ 250.518 What are the requirements for casing pressure management?

Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (incorporated by reference as specified in § 250.198) and the requirements of §§ 250.519 through 250.530. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.

§ 250.519 How often do I have to monitor for casing pressure?

You must monitor for casing pressure in your well according to the following table:

If you have * * *	you must monitor * * *	with a minimum one pressure data point recorded per * * *
(a) fixed platform wells,	monthly,	month for each casing.
(b) subsea wells,	continuously,	day for the production casing.
(c) hybrid wells,	continuously,	day for each riser and/or the production casing.
(d) wells operating under a casing pressure request on a manned fixed platform,	daily,	day for each casing.
(e) wells operating under a casing pressure request on an unmanned fixed platform,	weekly,	week for each casing.

§ 250.520 When do I have to perform a casing diagnostic test?

(a) You must perform a casing diagnostic test within 30 days after first observing or imposing casing pressure according to the following table:

If you have a * * *	you must perform a casing diagnostic test if * * *
(1) fixed platform well,	the casing pressure is greater than 100 psig.
(2) subsea well,	the measurable casing pressure is greater than the external hydrostatic pressure plus 100 psig measured at the subsea wellhead.
(3) hybrid well,	a riser or the production casing pressure is greater than 100 psig measured at the surface.

(b) You are exempt from performing a diagnostic pressure test for the production casing on a well operating under active gas lift.

§ 250.521 How do I manage the thermal effects caused by initial production on a newly completed or recompleted well?

A newly completed or recompleted well often has thermal casing pressure during initial startup. Bleeding casing pressure during the startup process is considered a normal and necessary operation to manage thermal casing pressure; therefore, you do not need to evaluate these operations as a casing diagnostic test. After 30 days of continuous production, the initial production startup operation is complete and you must perform casing diagnostic testing as required in §§ 250.520 and 250.522.

§ 250.522 When do I have to repeat casing diagnostic testing?

Casing diagnostic testing must be repeated according to the following table:

When * * *	you must repeat diagnostic testing * * *
(a) your casing pressure request approved term has expired,	immediately.
(b) your well, previously on gas lift, has been shut-in or returned to flowing status without gas lift for more than 180 days,	immediately on the production casing (A annulus). The production casing (A annulus) of wells on active gas lift are exempt from diagnostic testing.
(c) your casing pressure request becomes invalid,	within 30 days.
(d) a casing or riser has an increase in pressure greater than 200 psig over the previous casing diagnostic test,	within 30 days.
(e) after any corrective action has been taken to remediate undesirable casing pressure, either as a result of a casing pressure request denial or any other action,	within 30 days.
(f) your fixed platform well production casing (A annulus) has pressure exceeding 10 percent of its minimum internal yield pressure (MIYP), except for production casings on active gas lift,	once per year, not to exceed 12 months between tests.
(g) your fixed platform well's outer casing (B, C, D, etc., annuli) has a pressure exceeding 20 percent of its MIYP,	once every 5 years, at a minimum.

§ 250.523 How long do I keep records of casing pressure and diagnostic tests?

Records of casing pressure and diagnostic tests must be kept at the field office nearest the well for a minimum of 2 years. The last casing diagnostic test for each casing or riser must be retained at the field office nearest the well until the well is abandoned.

§ 250.524 When am I required to take action from my casing diagnostic test?

You must take action if you have any of the following conditions:

(a) Any fixed platform well with a casing pressure exceeding its maximum allowable wellhead operating pressure (MAWOP);

(b) Any fixed platform well with a casing pressure that is greater than 100 psig and that cannot bleed to 0 psig through a ½-inch needle valve within 24 hours, or is not bled to 0 psig during a casing diagnostic test;

(c) Any well that has demonstrated tubing/casing, tubing/riser, casing/casing, riser/casing, or riser/riser communication;

(d) Any well that has sustained casing pressure (SCP) and is bled down to prevent it from exceeding its MAWOP, except during initial startup operations described in § 250.521;

(e) Any hybrid well with casing or riser pressure exceeding 100 psig; or

(f) Any subsea well with a casing pressure 100 psig greater than the external hydrostatic pressure at the subsea wellhead.

§ 250.525 What do I submit if my casing diagnostic test requires action?

Within 14 days after you perform a casing diagnostic test requiring action under § 250.524:

You must submit either:	to the appropriate:	and it must include:	You must also:
(a) a notification of corrective action; or,	District Manager and copy the Regional Supervisor, Field Operations,	requirements under § 250.526	submit an Application for Permit to Modify or Corrective Action Plan within 30 days of the diagnostic test.
(b) a casing pressure request,	Regional Supervisor, Field Operations,	requirements under § 250.527.	

§ 250.526 What must I include in my notification of corrective action?

The following information must be included in the notification of corrective

(a) Lessee or Operator name;

(b) Area name and OCS block number;

(c) Well name and API number; and

(d) Casing diagnostic test data.

§ 250.527 What must I include in my casing pressure request?

The following information must be included in the casing pressure request:

(a) API number;

(b) Lease number;

(c) Area name and OCS block number;

(d) Well number;

(e) Company name and mailing address;

(f) All casing, riser, and tubing sizes, weights, grades, and MIYP;

(g) All casing/riser calculated MAWOPs;

(h) All casing/riser pre-bleed down pressures;

(i) Shut-in tubing pressure;

(j) Flowing tubing pressure;

(k) Date and the calculated daily production rate during last well test (oil, gas, basic sediment, and water);

(l) Well status (shut-in, temporarily abandoned, producing, injecting, or gas lift);

(m) Well type (dry tree, hybrid, or subsea);

(n) Date of diagnostic test;

(o) Well schematic;

(p) Water depth;

(q) Volumes and types of fluid bled from each casing or riser evaluated;

(r) Type of diagnostic test performed:

(1) Bleed down/buildup test;

(2) Shut-in the well and monitor the pressure drop test;

(3) Constant production rate and decrease the annular pressure test;

(4) Constant production rate and increase the annular pressure test;

(5) Change the production rate and monitor the casing pressure test; and

(6) Casing pressure and tubing pressure history plot;

(s) The casing diagnostic test data for all casing exceeding 100 psig;

(t) Associated shoe strengths for casing shoes exposed to annular fluids;

(u) Concentration of any H2S that may be present;

(v) Whether the structure on which the well is located is manned or unmanned;

(w) Additional comments; and

(x) Request date.

§ 250.528 What are the terms of my casing pressure request?

Casing pressure requests are approved by the Regional Supervisor, Field Operations, for a term to be determined by the Regional Supervisor on a case-by-case basis. The Regional Supervisor may impose additional restrictions or requirements to allow continued operation of the well.

§ 250.529 What if my casing pressure request is denied?

(a) If your casing pressure request is denied, then the operating company must submit plans for corrective action to the respective District Manager within 30 days of receiving the denial. The District Manager will establish a specific time period in which this corrective action will be taken. You must notify the respective District Manager within 30 days after completion of your corrected action.

(b) You must submit the casing diagnostic test data to the appropriate Regional Supervisor, Field Operations, within 14 days of completion of the diagnostic test required under § 250.522(e).

§ 250.530 When does my casing pressure request approval become invalid?

A casing pressure request becomes invalid when:

(a) The casing or riser pressure increases by 200 psig over the approved casing pressure request pressure;

(b) The approved term ends;

(c) The well is worked-over, side-tracked, redrilled, recompleted, or acid stimulated;

(d) A different casing or riser on the same well requires a casing pressure request; or

(e) A well has more than one casing operating under a casing pressure request and one of the casing pressure requests become invalid, then all casing pressure requests for that well become invalid.

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:

Expected surface pressure means the highest pressure predicted to be exerted upon the surface of a well. In calculating expected surface pressure, you must consider reservoir pressure as well as applied surface pressure.

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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 71 FR 11313, Mar. 7, 2006]

§ 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 Manager. 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 § 250.490 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 § 250.490 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; 68 FR 8435, Feb. 20, 2003]

§ 250.605 Subsea workovers.

No subsea well-workover operation including routine operations shall be commenced until the lessee obtains written approval from the District Manager 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 Manager to determine specific operating requirements, field well-workover rules may be established on the District Manager'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 Manager 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 Manager. Approval for these operations must be requested on Form MMS–124, Application for Permit to Modify.

(b) You must submit the following 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;

(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 § 250.490 of this part; and

(4) Payment of the service fee listed in § 250.125.

(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, Application for Permit to Modify, shall be submitted to the District Manager, 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, End of Operations Report, shall be submitted to the District Manager 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; 68 FR 8435, Feb. 20, 2003; 71 FR 40912, July 19, 2006; 72 FR 25201, May 4, 2007]

§ 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 must meet the appropriate standards from the following table:

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

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

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

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

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

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

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line 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) For coiled tubing operations with the production tree in place, you must meet the following minimum requirements for the BOP system:

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

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

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

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

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing well-workover operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form MMS–124, Application for Permit to Modify and have it approved by the District Manager.

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

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

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the

first full-opening valve on the choke line and the kill line.

(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, as amended at 68 FR 8435, Feb. 20, 2003; 71 FR 11313, Mar. 7, 2006; 71 FR 29710, May 23, 2006; 74 FR 46908, Sept. 14, 2009]

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

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

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

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

(3) *Other testing requirements.* Variable bore pipe rams must be pressure tested against the largest and smallest sizes of tubulars in use (jointed pipe, seamless pipe) in the well.

(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) You may conduct a stump test for the BOP system on location. A plan describing the stump test procedures must be included in your Form MMS–124, Application for Permit to Modify, and must be approved by the District Manager.

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

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

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system, system components, and marine risers 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 activity, 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 Manager.

[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; 71 FR 11313, Mar. 7, 2006]

§ 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 Manager.

(c) When reinstalling the tree, you must:

(1) Equip wells to monitor for casing pressure according to the following chart:

If you have * * *	you must equip * * *	so you can monitor * * *
(i) fixed platform wells, ...	the wellhead, ...	all annuli (A, B, C, D, etc., annuli).
(ii) subsea wells, ...	the tubing head, ...	the production casing annulus (A annulus).
(iii) hybrid* wells, ...	the surface wellhead, ...	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

*Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(2) Follow the casing pressure management requirements in subpart E of this part.

(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; 75 FR 23586, May 4, 2010]

§ 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 [Reserved]

Subpart H—Oil and Gas Production Safety Systems

§ 250.800 General requirements.

(a) 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.

(b) For all new floating production systems (FPSs) (e.g., column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc.), you must do all of the following:

(1) Comply with API RP 14J (incorporated by reference as specified in 30 CFR 250.198);

(2) Meet the drilling and production riser standards of API RP 2RD (incorporated by reference as specified in 30 CFR 250.198);

(3) Design all stationkeeping systems for floating facilities to meet the standards of API RP 2SK (incorporated by reference as specified in 30 CFR 250.198), as well as relevant U.S. Coast Guard regulations; and

(4) Design stationkeeping systems for floating facilities to meet structural requirements in subpart I, §§ 250.900 through 250.921 of this part.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 70 FR 41574, July 19, 2005]

§ 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 Manager 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 Manager'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 Manager.

(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 must be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems (incorporated by reference as specified in § 250.198).

(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 Manager 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 Manager 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, Application for Permit to Modify, 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 Manager.

(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; 72 FR 12096, Mar. 15, 2007; 72 FR 25201, May 4, 2007]

§ 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.* You must protect all platform production facilities with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with API RP 14C (incorporated by reference as specified in § 250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C you must utilize the analysis technique and documentation specified therein to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are under § 250.1004.

(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 SSVs and USVs must be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198). 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 Manager 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

Manager. 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 piping flow diagram (API RP 14C, Figure E, incorporated by reference as specified in § 250.198) and the related Safety analysis Function Evaluation chart (API RP 14C, subsection 4.3c, incorporated by reference as specified in § 250.198).

(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 (incorporated by reference as specified in § 250.198).

(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 (incorporated by reference as specified in § 250.198), 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 Manager 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.

(7) The service fee listed in § 250.125. The fee you must pay will be determined by the number of components involved in the review and approval process.

[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; 67 FR 51759, Aug. 9, 2002; 71 FR 40912, July 19, 2006; 72 FR 12096, Mar. 15, 2007; 72 FR 25201, May 4, 2007]

§ 250.803 Additional production system requirements.

(a) For all production platforms, you must comply with the following production safety system requirements, in addition to the requirements of § 250.802 of this subpart and the requirements of API RP 14C (incorporated by reference as specified in 30 CFR 250.198).

(b) *Design, installation, and operation of additional production systems*—(1) *Pressure and fired vessels.* Pressure and fired vessels must be designed, fabricated, and code stamped in accordance with the applicable provisions of Sections I, IV, and VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of API Pressure Vessel Inspections Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except

Sections 5.8 and 9.5) (incorporated by reference as specified in § 250.198).

(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 Manager. 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 Manager on a case-by-case basis.

(2) *Flowlines.* (i) You must equip flowlines from wells with high- and low-pressure shut-in sensors located in accordance with section A.1 and Figure A1 of API RP 14C (incorporated by reference as specified in § 250.198). 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 Manager. 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 Manager. 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.

(iii) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(A) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec 17J (incorporated by reference as specified in 30 CFR 250.198);

(B) Determine that the unbonded flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way;

(C) Submit to the MMS District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(D) Submit to the MMS District Manager a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of API Spec 17J (incorporated by reference as specified in 30 CFR 250.198).

(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 must conform to the requirements of Appendix C, section C1, of API RP 14C (incorporated by reference as specified in §250.198), 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 Manager.

(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 Manager.

(5) *Engines*—(i) *Engine exhaust.* You must equip engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4) (incorporated by reference as specified in §250.198). Exhaust piping from diesel engines must be equipped with spark arresters.

(ii) *Diesel engine air intake.* All diesel engine air intakes must be equipped with a device to shutdown the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote operated manual or automatic shutdown devices. Diesel engines that are not continuously attended must 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.* You must equip compressor installations with the following protective equipment as required in API RP 14C, Sections A4 and A8 (incorporated by reference as specified in §250.198).

(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 designated 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 Manager, 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 (incorporated by reference as specified in §250.198), Fire Prevention and Control Open Type Offshore Production Platforms, and shall require approval of the District Manager. 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 Manager.

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Manager 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 Manager 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 (incorporated by reference as specified in §250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (incorporated by reference as specified in §250.198).

(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 Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems must be an approved type, designed and installed according to API RP 14C, API RP 14G, and either API RP 14F or API RP 14FZ (the preceding four documents incorporated by reference as specified in § 250.198).

(10) *Electrical equipment.* Electrical equipment and systems shall be designed, installed, and maintained in accordance with the requirements in § 250.114 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, you are not required to comply with the provisions of API RP 14C (incorporated by reference as specified in § 250.198) 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 §§ 250.109 through 250.113 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; 67 FR 51759, Aug. 9, 2002; 68 FR 43298, July 22, 2003; 68 FR 65172, Nov. 19, 2003; 70 FR 7403, Feb. 14, 2005; 70 FR 41575, July 19, 2005; 72 FR 12096, Mar. 15, 2007; 73 FR 20171, Apr. 15, 2008; 74 FR 46909, Sept. 14, 2009; 75 FR 22226, Apr. 28, 2010]

§ 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 must be in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198), 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 (excluding electronic pressure transmitters and level sensors) must be tested at least once each calendar month, but at no time will 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) The following electronic pressure transmitters and level sensors must be tested at least once every 3 months, but at no time may more than 120 days elapse between tests:

(i) All PSH and PSL, and

(ii) All LSH and LSL controls.

(5) 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 SSV's and USV's must be tested in accordance with the test procedures specified in API RP 14H (incorporated by reference as specified in § 250.198). 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.

(6) 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 must be tested for leakage in accordance with the test procedures specified in API RP 14C, Appendix D, section D4, table D2, subsection D (incorporated by reference as specified in § 250.198). 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.

(7) 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.

(8) All pumps for firewater systems shall be inspected and operated weekly.

(9) 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.

(10) All TSH devices shall be tested at least once every 12 months, excluding those addressed in paragraph (a)(7) 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.

(11) 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.

(12) Prior to the commencement of production, the lessee shall notify the District Manager when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Manager 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 Manager. 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; 67 FR 51760, Aug. 9, 2002; 68 FR 47, Jan. 2, 2003]

§ 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–1–1994 and SPPE–1d–1996 Addenda, 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 for the Petroleum, Petrochemical and Natural Gas Industry (incorporated by reference as specified in § 250.198).

(3) All SSV's and USV's must meet the technical specifications of API Spec 6A and 6AV1. All SSSVs must meet the technical specifications of API Specification 14A (incorporated by reference as specified in § 250.198). However, SSSVs and related equipment planned to be used in high pressure high temperature environments must meet the additional requirements set forth in § 250.807.

(4) For information on all standards mentioned in this section, see § 250.198.

(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, Office of Offshore Regulatory Programs; Minerals Management Service; MS–4020; 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; 65 FR 76935, Dec. 8, 2000; 72 FR 12096, Mar. 15, 2007; 73 FR 20171, Apr. 15, 2008; 75 FR 1279, Jan. 11, 2010; 75 FR 22226, Apr. 28, 2010]

§ 250.807 Additional requirements for subsurface safety valves and related equipment installed in high pressure high temperature (HPHT) environments.

(a) If you plan to install SSSVs and related equipment in an HPHT environment, you must submit detailed information with your Application for Permit to Drill (APD), Application for

Permit to Modify (APM), or Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment are capable of performing in the applicable HPHT environment. Your detailed information must include the following:

(1) A discussion of the SSSVs' and related equipment's design verification analysis;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing process and procedures used; and

(3) An explanation of why the analysis, process, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

(b) For this section, HPHT environment means when one or more of the following well conditions exist:

(1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psig or a temperature rating greater than 350 degrees Fahrenheit;

(2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psig on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

(3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

(c) For this section, related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

[75 FR 1280, Jan. 11, 2010]

§ 250.808 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 § 250.490 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; 68 FR 8435, Feb. 20, 2003. Redesignated at 75 FR 1280, Jan. 11, 2010]

Subpart I—Platforms and Structures

SOURCE: 70 FR 41575, July 19, 2005, unless otherwise noted.

GENERAL REQUIREMENTS FOR PLATFORMS

§ 250.900 What general requirements apply to all platforms?

(a) You must design, fabricate, install, use, maintain, inspect, and assess all platforms and related structures on the Outer Continental Shelf (OCS) so as to ensure their structural integrity for the safe conduct of drilling, workover, and production operations. In doing this, you must consider the specific environmental conditions at the platform location.

(b) You must also submit an application under § 250.905 of this subpart and obtain the approval of the Regional Supervisor before performing any of the activities described in the following table:

Activity requiring application and approval	Conditions for conducting the activity
(1) Install a platform. This includes placing a newly constructed platform at a location or moving an existing platform to a new site.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) If you are installing a floating platform, you must also adhere to U.S. Coast Guard (USCG) regulations for the fabrication, installation, and inspection of floating OCS facilities.
(2) Major modification to any platform. This includes any structural changes that materially alter the approved plan or cause a major deviation from approved operations and any modification that increases loading on a platform by 10 percent or more.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major modification to a floating platform, you must obtain approval from both the MMS and the USCG for the modification.

Activity requiring application and approval	Conditions for conducting the activity
(3) Major repair of damage to any platform. This includes any corrective operations involving structural members affecting the structural integrity of a portion or all of the platform.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major repair to a floating platform, you must obtain approval from both the MMS and the USCG for the repair.
(4) Convert an existing platform at the current location for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing platform at the current location. (ii) At a minimum, your application must include: the converted platform's intended use; and a demonstration of the adequacy of the design and structural condition of the converted platform. (iii) If a floating platform, you must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.
(5) Convert an existing mobile offshore drilling unit (MODU) for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing MODU. (ii) At a minimum, your application must include: the converted MODU's intended location and use; a demonstration of the adequacy of the design and structural condition of the converted MODU; and a demonstration that the level of safety for the converted MODU is at least equal to that of re-used platforms. (iii) You must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.

(c) Under emergency conditions, you may make repairs to primary structural elements to restore an existing permitted condition without submitting an application or receiving prior MMS approval for up to 120-calendar days following an event. You must notify the Regional Supervisor of the damage that occurred within 24 hours of its discovery, and you must provide a written completion report to the Regional Supervisor of the repairs that were made within 1 week after completing the repairs. If you make emergency repairs on a floating platform, you must also notify the USCG.

(d) You must determine if your new platform or major modification to an existing platform is subject to the Platform Verification Program (PVP). Section 250.910 of this subpart fully describes the facilities that are subject to the PVP. If you determine that your platform is subject to the PVP, you must follow the requirements of §§ 250.909–250.918 of this subpart.

(e) You must submit notification of the platform installation date and the final as-built location data to the Regional Supervisor within 45-calendar days of completion of platform installation.

(1) For platforms not subject to the Platform Verification Program (PVP), MMS will cancel the approved platform application 1 year after the approval has been granted if the platform has not been installed. If MMS cancels the approval, you must resubmit your platform application and receive MMS approval if you still plan to install the platform.

(2) For platforms subject to the PVP, cancellation of an approval will be on an individual platform basis. For these platforms, MMS will identify the date when the installation approval will be cancelled (if installation has not occurred) during the application and approval process. If MMS cancels your installation approval, you must resubmit your platform application and receive MMS approval if you still plan to install the platform.

[70 FR 41575, July 19, 2005; 71 FR 16859, Apr. 4, 2006, as amended at 73 FR 20171, Apr. 15, 2008; 73 FR 64546, Oct. 30, 2008]

§ 250.901 What industry standards must your platform meet?

(a) In addition to the other requirements of this subpart, your plans for platform design, analysis, fabrication, installation, use, maintenance, inspection and assessment must, as appropriate, conform to:

(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95) (incorporated by reference at § 250.198);

(2) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997 (incorporated by reference at § 250.198);

(3) ANSI/AISC 360–05, Specification for Structural Steel Buildings, (incorporated by reference as specified in § 250.198);

(4) American Petroleum Institute (API) Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, (incorporated by reference as specified in § 250.198);

(5) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, (incorporated by reference as specified in § 250.198);

(6) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, (incorporated by reference as specified in § 250.198);

(7) API Recommend Practice (RP) 2A–WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design (incorporated by reference as specified in § 250.198);

(8) API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, (incorporated by reference as specified in § 250.198);

(9) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Drilling Units (incorporated by reference as specified in § 250.198);

(10) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), (incorporated by reference as specified in § 250.198);

(11) API RP 2SK, Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures, (incorporated by reference as specified in § 250.198);

(12) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, (incorporated by reference as specified in § 250.198);

(13) API RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms, (incorporated by reference as specified in § 250.198);

(14) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, (incorporated by reference as specified in § 250.198);

(15) American Society for Testing and Materials (ASTM) Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates (incorporated by reference as specified in § 250.198);

(16) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete (incorporated by reference as specified in § 250.198);

(17) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement (incorporated by reference as specified in § 250.198);

(18) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete (incorporated by reference as specified in § 250.198);

(19) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements (incorporated by reference as specified in § 250.198);

(20) AWS D1.1, Structural Welding Code—Steel, including Commentary, (incorporated by reference as specified in § 250.198);

(21) AWS D1.4, Structural Welding Code—Reinforcing Steel, (incorporated by reference as specified in § 250.198);

(22) AWS D3.6M, Specification for Underwater Welding, (incorporated by reference as specified in § 250.198);

(23) NACE Standard MR0175, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, (incorporated by reference as specified in § 250.198);

(24) NACE Standard RP0176–2003, Item No. 21018, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production.

(b) You must follow the requirements contained in the documents listed under paragraph (a) of this section insofar as they do not conflict with other provisions of 30 CFR part 250. You may use applicable provisions of these documents, as approved by the Regional Supervisor, for the design, fabrication, and installation of platforms such as spars, since standards specifically written for such structures do not exist. You may also use alternative codes, rules, or standards, as approved by the

Regional Supervisor, under the conditions enumerated in § 250.141.

(c) For information on the standards mentioned in this section, and where they may be obtained, see § 250.198 of this part.

(d) The following chart summarizes the applicability of the industry standards listed in this section for fixed and floating platforms:

Industry standard	Applicable to * * *
(1) ACI Standard 318–95, Building Code Requirements for Reinforced Concrete (ACI 318–95) and Commentary (ACI 318R–95).	Fixed and floating platform, as appropriate.
(2) ANSI/AISC 360–05, Specification for Structural Steel Buildings;.	
(3) API Bulletin 2INT–DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions;.	
(4) API Bulletin 2INT–EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions;.	
(5) API Bulletin 2INT–MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico;.	
(6) API RP 2A–WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design;.	
(7) ASTM Standard C 33–07, approved December 15, 2007, Standard Specification for Concrete Aggregates;.	
(8) ASTM Standard C 94/C 94M–07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete;.	
(9) ASTM Standard C 150–07, approved May 1, 2007, Standard Specification for Portland Cement;.	
(10) ASTM Standard C 330–05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete;.	
(11) ASTM Standard C 595–08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements;.	
(12) AWS D1.1, Structural Welding Code—Steel;.	
(13) AWS D1.4, Structural Welding Code—Reinforcing Steel;.	
(14) AWS D3.6M, Specification for Underwater Welding;.	
(15) NACE Standard RP 0176–2003, Standard Recommended Practice (RP), Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production;.	
(16) ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved 1997.	Fixed platforms
(17) API RP 14J, RP for Design and Hazards Analysis for Offshore Production Facilities;.	Floating platforms.
(18) API RP 2FPS, RP for Planning, Designing, and Constructing, Floating Production Systems;.	
(19) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs);.	
(20) API RP 2SK, RP for Design and Analysis of Station Keeping Systems for Floating Structures;.	
(21) API RP 2T, RP for Planning, Designing, and Constructing Tension Leg Platforms;.	
(22) API RP 2SM, RP for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring;.	
(23) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Drilling Units..	

[70 FR 41575, July 19, 2005, as amended at 72 FR 12096, Mar. 15, 2007; 73 FR 20169, Apr. 15, 2008; 73 FR 64546, Oct. 30, 2008; 75 FR 22226, Apr. 28, 2010]

§ 250.902 What are the requirements for platform removal and location clearance?

You must remove all structures according to §§ 250.1725 through 250.1730 of Subpart Q—Decommissioning Activities of this part.

§ 250.903 What records must I keep?

(a) You must compile, retain, and make available to MMS representatives for the functional life of all platforms:

(1) The as-built drawings;

(2) The design assumptions and analyses;

(3) A summary of the fabrication and installation nondestructive examination records;

(4) The inspection results from the inspections required by § 250.919 of this subpart; and

(5) Records of repairs not covered in the inspection report submitted under § 250.919(b).

(b) You must record and retain the original material test results of all primary structural materials during all stages of construction. Primary material is material that, should it fail, would lead to a significant reduction in platform safety, structural reliability, or operating capabilities. Items such as steel brackets, deck stiffeners and secondary braces or beams would not generally be considered primary structural members (or materials).

(c) You must provide MMS with the location of these records in the certification statement of your application for platform approval as required in § 250.905(j).

PLATFORM APPROVAL PROGRAM

§ 250.904 What is the Platform Approval Program?

(a) The Platform Approval Program is the MMS basic approval process for platforms on the OCS. The requirements of the Platform Approval Program are described in §§ 250.904 through 250.908 of this subpart. Completing these requirements will satisfy MMS criteria for approval of fixed platforms of a proven design that will be placed in the shallow water areas (≤ 400 ft.) of the Gulf of Mexico OCS.

(b) The requirements of the Platform Approval Program must be met by all platforms on the OCS. Additionally, if you want approval for a floating platform; a platform of unique design; or a platform being installed in deepwater (> 400 ft.) or a frontier area, you must also meet the requirements of the Platform Verification Program. The requirements of the Platform Verification Program are described in §§ 250.909 through 250.918 of this subpart.

§ 250.905 How do I get approval for the installation, modification, or repair of my platform?

The Platform Approval Program requires that you submit the information, documents, and fee listed in the following table for your proposed project. In lieu of submitting the paper copies specified in the table, you may submit your application electronically in accordance with 30 CFR 250.186(a)(3).

Required submittal	Required contents	Other requirements
(a) Application cover letter	Proposed structure designation, lease number, area, name, and block number, and the type of facility your facility (e.g., drilling, production, quarters). The structure designation must be unique for the field (some fields are made up of several blocks); *i.e.* once a platform "A" has been used in the field there should never be another platform "A" even if the old platform "A" has been removed. Single well free standing caissons should be given the same designation as the well. All other structures are to be designated by letter designations.	You must submit three copies. If, your facility is subject to the Platform Verficiation Program (PVP), you must submit four copies.
(b) Location plat	Latitude and longitude coordinates, Universal Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection System, and distances in feet from the nearest block lines. These coordinates must be based on the NAD (North American Datum) 27 datum plane coordinate system.	Your plat must be drawn to a scale of 1 inch equals 2,000 feet and include the coordinates of the lease block boundary lines. You must submit three
(c) Front, Side, and Plan View drawings.	Platform dimensions and orientation, elevations relative to M.L.L.W. (Mean Lower Low Water), and pile sizes and penetration.	Your drawing sizes must not exceed 11″ × 17″. You must submit three copies (four copies for PVP applications).
(d) Complete set of structural drawings.	The approved for construction fabrication drawings should be submitted including; e.g., cathodic protection systems; jacket design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; mooring and tethering systems; foundations and anchoring systems.	Your drawing sizes must not exceed 11″ × 17″. You must submit one copy.
(e) Summary of environmental data	A summary of the environmental data described in the applicable standards referenced under § 250.901(a) of this subpart and in § 250.198 of Subpart A, where the data is used in the design or analysis of the platform. Examples of relevant data include information on waves, wind, current, tides, temperature, snow and ice effects, marine growth, and water depth.	You must submit one copy.

Required submittal	Required contents	Other requirements
(f) Summary of the engineering design data.	Loading information (e.g., live, dead, environmental), structural information (e.g., design-life; material types; cathodic protection systems; design criteria; fatigue life; jacket design; deck design; production component design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; mooring or tethering systems; fabrication and installation guidelines), and foundation information (e.g., soil stability, design criteria).	You must submit one copy.
(g) Project-specific studies used in the platform design or installation.	All studies pertinent to platform design or installation, e.g., oceanographic and/or soil reports including the overall site investigative report required in section 250.906.	You must submit one copy of each study.
(h) Description of the loads imposed on the facility.	Loads imposed by jacket; decks; production components; drilling, production, and pipeline risers, and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; and mooring or tethering systems.	You must submit one copy.
(i) Summary of safety factors utilized.	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.	You must submit one copy.
(j) A copy of the in-service inspection plan.	This plan is described in § 250.919.	You must submit one copy.
(k) Certification statement	The following statement: "The design of this structure has been certified by a recognized classification society, or a registered civil or structural engineer or equivalent, or a naval architect or marine engineer or equivalent, specializing in the design of offshore structures. The certified design and as-built plans and specifications will be on file at (give location)".	An authorized company representative must sign the statement. You must submit one copy.
(l) Payment of the service fee listed in § 250.125.	....	

[70 FR 41575, July 19, 2005, as amended at 71 FR 40912, July 19, 2006; 73 FR 64546, Oct. 30, 2008]

§ 250.906 What must I do to obtain approval for the proposed site of my platform?

(a) *Shallow hazards surveys.* You must perform a high-resolution or acoustic-profiling survey to obtain information on the conditions existing at and near the surface of the seafloor. You must collect information through this survey sufficient to determine the presence of the following features and their likely effects on your proposed platform:

(1) Shallow faults;

(2) Gas seeps or shallow gas;

(3) Slump blocks or slump sediments;

(4) Shallow water flows;

(5) Hydrates; or

(6) Ice scour of seafloor sediments.

(b) *Geologic surveys.* You must perform a geological survey relevant to the design and siting of your platform. Your geological survey must assess:

(1) Seismic activity at your proposed site;

(2) Fault zones, the extent and geometry of faulting, and attenuation effects of geologic conditions near your site; and

(3) For platforms located in producing areas, the possibility and effects of seafloor subsidence.

(c) *Subsurface surveys.* Depending upon the design and location of your proposed platform and the results of the shallow hazard and geologic surveys, the Regional Supervisor may require you to perform a subsurface survey. This survey will include a testing program for investigating the stratigraphic and engineering properties of the soil that may affect the foundations or anchoring systems for your facility. The testing program must include adequate in situ testing, boring, and sampling to examine all important soil and rock strata to determine its strength classification, deformation properties, and dynamic characteristics. If required to perform a subsurface survey, you must prepare and submit to the Regional Supervisor a summary report to briefly describe the results of your soil testing program, the various field and laboratory test methods employed, and the applicability of these methods as they pertain to the quality of the samples, the type of soil, and the anticipated design application. You must explain how the engineering properties of each soil stratum affect the design of your platform. In your explanation you must describe the uncertainties inherent in your overall testing program, and the reliability and applicability of each test method.

(d) *Overall site investigation report.* You must prepare and submit to the Regional Supervisor an overall site investigation report for your platform that integrates the findings of your shallow hazards surveys and geologic surveys, and, if required, your subsurface surveys. Your overall site investigation report must include analyses of the potential for:

(1) Scouring of the seafloor;

(2) Hydraulic instability;

(3) The occurrence of sand waves;

(4) Instability of slopes at the platform location;

(5) Liquifaction, or possible reduction of soil strength due to increased pore pressures;

(6) Degradation of subsea permafrost layers;

(7) Cyclic loading;

(8) Lateral loading;

(9) Dynamic loading;

(10) Settlements and displacements;

(11) Plastic deformation and formation collapse mechanisms; and

(12) Soil reactions on the platform foundations or anchoring systems.

§ 250.907 Where must I locate foundation boreholes?

(a) For fixed or bottom-founded platforms and tension leg platforms, your maximum distance from any foundation pile to a soil boring must not exceed 500 feet.

(b) For deepwater floating platforms which utilize catenary or taut-leg moorings, you must take borings at the most heavily loaded anchor location, at the anchor points approximately 120 and 240 degrees around the anchor pattern from that boring, and, as necessary, other points throughout the anchor pattern to establish the soil profile suitable for foundation design purposes.

§ 250.908 What are the minimum structural fatigue design requirements?

(a) API RP 2A-WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms (incorporated by reference as specified in 30 CFR 250.198), requires that the design fatigue life of each joint and member be twice the intended service life of the structure. When designing your platform, the following table provides minimum fatigue life safety factors for critical structural members and joints.

If . . .	Then . . .
(1) There is sufficient structural redundancy to prevent catastrophic failure of the platform or structure under consideration.	The results of the analysis must indicate a maximum calculated life of twice the design life of the platform.
(2) There is not sufficient structural redundancy to prevent catastrophic failure of the platform or structure.	The results of a fatigue analysis must indicate a minimum calculated life or three times the design life of the platform.
(3) The desirable degree of redundancy is significantly reduced as a result of fatigue damage.	The results of a fatigue analysis must indicate a minimum calculated life of three times the design life of the platform.

(b) The documents incorporated by reference in § 250.901 may require larger safety factors than indicated in paragraph (a) of this section for some key components. When the documents incorporated by reference require a larger safety factor than the chart in paragraph (a) of this section, the requirements of the incorporated document will prevail.

PLATFORM VERIFICATION PROGRAM

§ 250.909 What is the Platform Verification Program?

The Platform Verification Program is the MMS approval process for ensuring that floating platforms; platforms of a new or unique design; platforms in seismic areas; or platforms located in deepwater or frontier areas meet stringent requirements for design and construction. The program is applied during construction of new platforms and major modifications of, or repairs to, existing platforms. These requirements are in addition to the requirements of the Platform Approval Program described in §§ 250.904 through 250.908 of this subpart.

§ 250.910 Which of my facilities are subject to the Platform Verification Program?

(a) All new fixed or bottom-founded platforms that meet any of the following five conditions are subject to the Platform Verification Program:

(1) Platforms installed in water depths exceeding 400 feet (122 meters);

(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.

(b) All new floating platforms are subject to the Platform Verification Program to the extent indicated in the following table:

If . . .	Then . . .
(1) Your new floating platform is a buoyant offshore facility that does not have a ship-shaped hull.	The entire platform is subject to the Platform Verification Program including the following associated structures: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser does not have tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.
(2) Your new floating platform is a buoyant offshore facility with a ship-shaped hull.	Only the following structures that may be associated with a floating platform are subject to the Platform Verification Program: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) If a platform is originally subject to the Platform Verification Program, then the conversion of that platform at that same site for a new purpose, or making a major modification of, or major repair to, that platform, is also subject to the Platform Verification Program. A major modification includes any modification that increases loading on a platform by 10 percent or more. A major repair is a corrective operation involving structural members affecting the structural integrity of a portion or all of the platform. Before you make a major modification or repair to a floating platform, you must obtain approval from both the MMS and the USCG.

(d) The applicability of Platform Verification Program requirements to other types of facilities will be determined by MMS on a case-by-case basis.

[70 FR 41575, July 19, 2005; 71 FR 28080, May 15, 2006]

§ 250.911 If my platform is subject to the Platform Verification Program, what must I do?

If your platform, conversion, or major modification or repair meets the criteria in § 250.910, you must:

(a) Design, fabricate, install, use, maintain and inspect your platform, conversion, or major modification or repair to your platform according to the requirements of this subpart, and the applicable documents listed in § 250.901(a) of this subpart;

(b) Comply with all the requirements of the Platform Approval Program found in §§ 250.904 through 250.908 of this subpart.

(c) Submit for the Regional Supervisor's approval three copies each of the design verification, fabrication verification, and installation verification plans required by § 250.912;

(d) Submit a complete schedule of all phases of design, fabrication, and installation for the Regional Supervisor's approval. You must include a project management timeline, Gantt Chart, that depicts when interim and final reports required by §§ 250.916, 250.917, and 250.918 will be submitted to the Regional Supervisor for each phase. On the timeline, you must break-out the specific scopes of work that inherently stand alone (e.g., deck, mooring systems, tendon systems, riser systems, turret systems).

(e) Include your nomination of a Certified Verification Agent (CVA) as a part of each verification plan required by § 250.912;

(f) Follow the additional requirements in §§ 250.913 through 250.918;

(g) Obtain approval for modifications to approved plans and for major deviations from approved installation procedures from the Regional Supervisor; and

(h) Comply with applicable USCG regulations for floating OCS facilities.

[70 FR 41575, July 19, 2005, as amended at 73 FR 64547, Oct. 30, 2008]

§ 250.912 What plans must I submit under the Platform Verification Program?

If your platform, associated structure, or major modification meets the criteria in § 250.910, you must submit the following plans to the Regional Supervisor for approval:

(a) *Design verification plan*. You may submit your design verification plan with or subsequent to the submittal of your Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD). Your design verification must be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer or equivalent, or a naval architect or marine engineer or equivalent, with previous experience in directing the design of similar facilities, systems, structures, or equipment. For floating platforms, you must ensure that the requirements of the USCG for structural integrity and stability, e.g., verification of center of gravity, etc., have been met. Your design verification plan must include the following:

(1) All design documentation specified in § 250.905 of this subpart;

(2) Abstracts of the computer programs used in the design process; and

(3) A summary of the major design considerations and the approach to be used to verify the validity of these design considerations.

(b) *Fabrication verification plan*. The Regional Supervisor must approve your fabrication verification plan before you may initiate any related operations. Your fabrication verification plan must include the following:

(1) Fabrication drawings and material specifications for artificial island structures and major members of concrete-gravity and steel-gravity structures;

(2) For jacket and floating structures, all the primary load-bearing members included in the space-frame analysis; and

(3) 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 for welds and materials; and

(vii) Quality assurance procedures.

(c) *Installation verification plan.* The Regional Supervisor must approve your installation verification plan before you may initiate any related operations. Your installation verification plan must include:

(1) A summary description of the planned marine operations;

(2) Contingencies considered;

(3) Alternative courses of action; and

(4) An identification of the areas to be inspected. You must specify the acceptance and rejection criteria to be used for any inspections conducted during installation, and for the post-installation verification inspection.

(d) You must combine fabrication verification and installation verification plans for manmade islands or platforms fabricated and installed in place.

§ 250.913 When must I resubmit Platform Verification Program plans?

(a) You must resubmit any design verification, fabrication verification, or installation verification plan to the Regional Supervisor for approval if:

(1) The CVA changes;

(2) The CVA's or assigned personnel's qualifications change; or

(3) The level of work to be performed changes.

(b) If only part of a verification plan is affected by one of the changes described in paragraph (a) of this section, you can resubmit only the affected part. You do not have to resubmit the summary of technical details unless you make changes in the technical details.

§ 250.914 How do I nominate a CVA?

(a) As part of your design verification, fabrication verification, or installation verification plan, you must nominate a CVA for the Regional Supervisor's approval. You must specify whether the nomination is for the design, fabrication, or installation phase of verification, or for any combination of these phases.

(b) For each CVA, you must submit a list of documents to be forwarded to the CVA, and a qualification statement that includes the following:

(1) Previous experience in third-party verification or experience in the design, fabrication, installation, or major modification of offshore oil and gas platforms. This should include fixed platforms, floating platforms, manmade islands, other similar marine structures, and related systems and equipment;

(2) Technical capabilities of the individual or the primary staff for the specific project;

(3) Size and type of organization or corporation;

(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(5) Ability to perform the CVA functions for the specific project considering current commitments;

(6) Previous experience with MMS requirements and procedures;

(7) The level of work to be performed by the CVA.

§ 250.915 What are the CVA's primary responsibilities?

(a) The CVA must conduct specified reviews according to §§ 250.916, 250.917, and 250.918 of this subpart.

(b) Individuals or organizations acting as CVAs must not function in any capacity that would create a conflict of interest, or the appearance of a conflict of interest.

(c) The CVA must consider the applicable provisions of the documents listed in § 250.901(a); the alternative codes, rules, and standards approved under 250.901(b); and the requirements of this subpart.

(d) The CVA is the primary contact with the Regional Supervisor and is directly responsible for providing immediate reports of all incidents that affect the design, fabrication and installation of the platform.

§ 250.916 What are the CVA's primary duties during the design phase?

(a) The CVA must use good engineering judgement and practices in conducting an independent assessment of the design of the platform, major modification, or repair. The CVA must ensure that the platform, major modification, or repair is designed to withstand the environmental and functional load conditions appropriate for the intended service life at the proposed location.

(b) Primary duties of the CVA during the design phase include the following:

Type of facility . . .	The CVA must . . .
(1) For fixed platforms and non-ship-shaped floating facilities	Conduct an independent assessment of all proposed: (i) Planning criteria; (ii) Operational requirements; (iii) Environmental loading data; (iv) Load determinations; (v) Stress analyses; (vi) Material designations; (vii) Soil and foundation conditions; (viii) Safety factors; and (ix) Other pertinent parameters of the proposed design.
(2)For all floating facilities	Ensure that the requirements of the U.S. Coast Guard for structural integrity and stability, e.g., verification of center of gravity, etc., have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems; (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the design phase in accordance with the approved schedule required by § 250.911(d). In each interim and final report the CVA must:

(1) Provide a summary of the material reviewed and the CVA's findings;

(2) In the final CVA report, make a recommendation that the Regional Supervisor either accept, request modifications, or reject the proposed design unless such a recommendation has been previously made in an interim report;

(3) Describe the particulars of how, by whom, and when the independent review was conducted; and

(4) Provide any additional comments the CVA deems necessary.

[70 FR 41575, July 19, 2005, as amended at 73 FR 64547, Oct. 30, 2008]

§ 250.917 What are the CVA's primary duties during the fabrication phase?

(a) The CVA must use good engineering judgement and practices in conducting an independent assessment of the fabrication activities. The CVA must monitor the fabrication of the platform or major modification to ensure that it has been built according to the approved design and the fabrication plan. If the CVA finds that fabrication procedures are changed or design specifications are modified, the CVA must inform you. If you accept the modifications, then the CVA must so inform the Regional Supervisor.

(b) Primary duties of the CVA during the fabrication phase include the following:

Type of facility . . .	The CVA must . . .
(1) For all fixed platforms and non-ship-shaped floating facilities	Make periodic onsite inspections while fabrication is in progress and must verify the following fabrication items, as appropriate: (i) Quality control by lessee and builder; (ii) Fabrication site facilities; (iii) Material quality and identification methods; (iv) Fabrication procedures specified in the approved plan, and adherence to such procedures; (v) Welder and welding procedure qualification and identification; (vi) Structural tolerences specified and adherence to those tolerances; (vii) The nondestructive examination requirements, and evaluation results of the specified examinations; (viii) Destructive testing requirements and results;

Type of facility . . .	The CVA must . . .
	(ix) Repair procedures; (x) Installation of corrosion-protection systems and splash-zone protection; (xi) Erection procedures to ensure that overstressing of structural members does not occur; (xii) Alignment procedures; (xiii) Dimensional check of the overall structure, including any turrets, turret-and-hull interfaces, any mooring line and chain and riser tensioning line segments; and (xiv) Status of quality-control records at various stages of fabrication.
(2) For all floating facilities	Ensure that the requirements of the U.S. Coast Guard floating for structural integrity and stability, e.g., verification of center of gravity, etc., have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial fabrication of these elements); (ii) Turrets and turret-and-hull interfaces; (iii) Foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the fabrication phase in accordance with the approved schedule required by §250.911(d). In each interim and final report the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Describe the CVA's activities during the verification process;

(3) Summarize the CVA's findings;

(4) Confirm or deny compliance with the design specifications and the approved fabrication plan;

(5) In the final CVA report, make a recommendation to accept or reject the fabrication unless such a recommendation has been previously made in an interim report; and

(6) Provide any additional comments that the CVA deems necessary.

[70 FR 41575, July 19, 2005, as amended at 73 FR 64547, Oct. 30, 2008]

§250.918 What are the CVA's primary duties during the installation phase?

(a) The CVA must use good engineering judgment and practice in conducting an independent assessment of the installation activities.

(b) Primary duties of the CVA during the installation phase include the following:

The CVA must . . .	Operation or equipment to be inspected . . .
(1) Verify, as appropriate	(i) Loadout and initial flotation operations; (ii) Towing operations to the specified location, and review the towing records; (iii) Launching and uprighting operations; (iv) Submergence operations; (v) Pile or anchor installations; (vi) Installation of mooring and tethering systems; (vii) Final deck and component installations; and (viii) Installation at the approved location according to the approved design and the installation plan.
(2) Witness (for a fixed or floating platform)	(i) The loadout of the jacket, decks, piles, or structures from each fabrication site; (ii) The actual installation of the platform or major modification and the related installation activities.
(3) Witness (for a floating platform)	(i) The loadout of the platform; (ii) The installation of drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial installation of these elements); (iii) The installation of turrets and turret-and-hull interfaces; (iv) The installation of foundation pilings and templates, and anchoring systems; and (v) The installation of the mooring and tethering systems.

The CVA must . . .	Operation or equipment to be inspected . . .
(4) Conduct an onsite survey	Survey the platform after transportation to the approved location.
(5) Spot-check as necessary to determine compliance with the applicable documents listed in § 250.901(a); the alternative codes, rules and standards approved under 250.901(b); the requirements listed in § 250.903 and § 250.906 through 250.908 of this subpart and the approved plans.	(i) Equipment; (ii) Procedures; and (iii) Recordkeeping.

(c) The CVA must submit interim reports and a final report to the Regional Supervisor, and to you, during the installation phase in accordance with the approved schedule required by § 250.911(d). In each interim and final report the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Describe the CVA's activities during the verification process;

(3) Summarize the CVA's findings;

(4) Confirm or deny compliance with the approved installation plan;

(5) In the final report, make a recommendation to accept or reject the installation unless such a recommendation has been previously made in an interim report; and

(6) Provide any additional comments that the CVA deems necessary.

[70 FR 41575, July 19, 2005, as amended at 73 FR 64547, Oct. 30, 2008]

INSPECTION, MAINTENANCE, AND ASSESSMENT OF PLATFORMS

§ 250.919 What in-service inspection requirements must I meet?

(a) You must submit a comprehensive in-service inspection report annually by November 1 to the Regional Supervisor that must include:

(1) A list of fixed and floating platforms you inspected in the preceding 12 months;

(2) The extent and area of inspection for both the above-water and underwater portions of the platform and the pertinent components of the mooring system for floating platforms;

(3) The type of inspection employed (e.g., visual, magnetic particle, ultrasonic testing);

(4) The overall structural condition of each platform, including a corrosion protection evaluation; and

(5) A summary of the inspection results indicating what repairs, if any, were needed.

(b) If any of your structures have been exposed to a natural occurrence (e.g., hurricane, earthquake, or tropical storm), the Regional Supervisor may require you to submit an initial report of all structural damage, followed by subsequent updates, which include the following:

(1) A list of affected structures;

(2) A timetable for conducting the inspections described in section 14.4.3 of API RP 2A–WSD (incorporated by reference as specified in § 250.198); and

(3) An inspection plan for each structure that describes the work you will perform to determine the condition of the structure.

(c) The Regional Supervisor may also require you to submit the results of the inspections referred to in paragraph (b)(2) of this section, including a description of any detected damage that may adversely affect structural integrity, an assessment of the structure's ability to withstand any anticipated environmental conditions, and any remediation plans. Under §§ 250.900(b)(3) and 250.905, you must obtain approval from MMS before you make major repairs of any damage unless you meet the requirements of § 250.900(c).

[73 FR 64547, Oct. 30, 2008]

§ 250.920 What are the MMS requirements for assessment of fixed platforms?

(a) You must document all wells, equipment, and pipelines supported by the platform if you intend to use either the A–2 or A–3 assessment category. Assessment categories are defined in API RP 2A–WSD, Section 17.3. If MMS objects to the assessment category you used for your assessment, you may need to redesign and/or modify the platform to adequately demonstrate that the platform is able to withstand the environmental loadings for the appropriate assessment category.

(b) You must perform an analysis check when your platform will have additional personnel, additional topside facilities, increased environmental or operational loading, or inadequate deck height your platform suffered significant damage (e.g., experienced damage to primary structural members or conductor guide trays or global structural integrity is adversely affected); or the exposure category changes to a more restrictive level (see Sections 17.2.1 through 17.2.5 of API RP 2A–WSD for a description of assessment initiators).

(c) You must initiate mitigation actions for platforms that do not pass the assessment process of API RP 2A–WSD. You must submit applications for your mitigation actions (e.g., repair, modification, decommissioning) to the Regional Supervisor for approval before you conduct the work.

(d) The MMS may require you to conduct a platform design basis check when the reduced environmental loading criteria contained in API RP 2A–WSD Section 17.6 are not applicable.

(e) By November 1, 2009, you must submit a complete list of all the platforms you operate, together with all the appropriate data to support the assessment category you assign to each platform and the platform assessment initiators (as defined in API RP 2A–WSD) to the Regional Supervisor. You must submit subsequent complete lists and the appropriate data to support the consequence-of-failure category every 5 years thereafter, or as directed by the Regional Supervisor.

(f) The use of Section 17, Assessment of Existing Platforms, of API RP 2A–WSD is limited to existing fixed structures that are serving their original approved purpose. You must obtain approval from the Regional Supervisor for any change in purpose of the platform, following the provisions of API RP 2A–WSD, Section 15, Re-use.

[73 FR 64548, Oct. 30, 2008]

§250.921 How do I analyze my platform for cumulative fatigue?

(a) If you are required to analyze cumulative fatigue on your platform because of the results of an inspection or platform assessment, you must ensure that the safety factors for critical elements listed in §250.908 are met or exceeded.

(b) If the calculated life of a joint or member does not meet the criteria of §250.908, you must either mitigate the load, strengthen the joint or member, or develop an increased inspection process.

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 must be accompanied by payment of the service fee listed in §250.125 and submitted to the Regional Supervisor and approval obtained before:

(1) Installation, modification, or abandonment of a lease term pipeline;

(2) Installation or modification of a right-of-way (other than lease term) pipeline; or

(3) 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.

(6) Any producer operating a pipeline that crosses into State waters without first connecting to a transporting operator's facility on the OCS must comply with this subpart. Compliance must extend from the point where hydrocarbons are first produced, through and including the last valve and associated safety equipment (e.g., pressure safety sensors) on the last production facility on the OCS.

(7) Any producer operating a pipeline that connects facilities on the OCS must comply with this subpart.

(8) Any operator of a pipeline that has a valve on the OCS downstream (landward) of the last production facility may ask in writing that the MMS Regional Supervisor recognize that valve as the last point MMS will exercise its regulatory authority.

(9) A pipeline segment is not subject to MMS regulations for design, construction, operation, and maintenance if:

(i) It is downstream (generally shoreward) of the last valve and associated safety equipment on the last production facility on the OCS; and

(ii) It is subject to regulation under 49 CFR parts 192 and 195.

(10) DOT may inspect all upstream safety equipment (including valves, over-pressure protection devices, cathodic protection equipment, and pigging devices, etc.) that serve to protect the integrity of DOT-regulated pipeline segments.

(11) OCS pipeline segments not subject to DOT regulation under 49 CFR parts 192 and 195 are subject to all MMS regulations.

(12) A producer may request that its pipeline operate under DOT regulations governing pipeline design, construction, operation, and maintenance.

(i) The operator's request must be in the form of a written petition to the MMS Regional Supervisor that states the justification for the pipeline to operate under DOT regulation.

(ii) The Regional Supervisor will decide, on a case-by-case basis, whether to grant the operator's request. In considering each petition, the Regional Supervisor will consult with the Office of Pipeline Safety (OPS) Regional Director.

(13) A transporter who operates a pipeline regulated by DOT may request to operate under MMS regulations governing pipeline operation and maintenance. Any subsequent repairs or modifications will also be subject to MMS regulations governing design and construction.

(i) The operator's request must be in the form of a written petition to the OPS Regional Director and the MMS Regional Supervisor.

(ii) The MMS Regional Supervisor and the OPS Regional Director will decide how to act on this petition.

(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; 65 FR 46095, July 27, 2000; 71 FR 40912, July 19, 2006]

§ 250.1001 Definitions.

Terms used in this subpart shall have the meanings given below:

DOI pipelines include:

(1) Producer-operated pipelines extending upstream (generally seaward) from each point on the OCS at which operating responsibility transfers from a producing operator to a transporting operator;

(2) Producer-operated pipelines extending upstream (generally seaward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not connect to a transporter-operated pipeline on the OCS before crossing into State waters;

(3) Producer-operated pipelines connecting production facilities on the OCS;

(4) Transporter-operated pipelines that DOI and DOT have agreed are to be regulated as DOI pipelines; and

(5) All OCS pipelines not subject to regulation under 49 CFR parts 192 and 195.

DOT pipelines include:

(1) Transporter-operated pipelines currently operated under DOT requirements governing design, construction, maintenance, and operation;

(2) Producer-operated pipelines that DOI and DOT have agreed are to be regulated under DOT requirements governing design, construction, maintenance, and operation; and

(3) Producer-operated pipelines downstream (generally shoreward) of the last valve (including associated safety equipment) on the last production facility on the OCS that do not connect to a transporter-operated pipeline on the OCS before crossing into State waters and that are regulated under 49 CFR parts 192 and 195.

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.

Out-of-service pipelines are those pipelines that have not been used to transport oil, natural gas, sulfur, or produced water for more than 30 consecutive days.

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.)

Production facilities means OCS facilities that receive hydrocarbon production either directly from wells or from other facilities that produce hydrocarbons from wells. They may include processing equipment for treating the production or separating it into its various liquid and gaseous components before transporting it to shore.

Right-of-way pipelines are those pipelines which—

(1) Are contained within the boundaries of a single lease or group of unitized leases but are not owned and operated by the lessee or operator of that lease or unit,

(2) Are contained within the boundaries of contiguous (not cornering) leases which do not have a common lessee or operator,

(3) Are contained within the boundaries of contiguous (not cornering) leases which have a common lessee or operator but are not owned and operated by that common lessee or operator, or

(4) 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; 65 FR 46096, July 27, 2000; 67 FR 35405, May 17, 2002; 72 FR 25201, May 4, 2007]

§ 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 (incorporated by reference as specified in 30 CFR 250.198) 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 (incorporated by reference as specified in 30 CFR 250.198). 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.

(4) If you are installing pipelines constructed of unbonded flexible pipe, you must design them according to the standards and procedures of API Spec 17J, incorporated by reference as specified in 30 CFR 250.198.

(5) You must design pipeline risers for tension leg platforms and other floating platforms according to the design standards of API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs), incorporated by reference as specified in 30 CFR 250.198.

(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) pressure 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, you must install and maintain redundant safety devices meeting the requirements of section A9 of API RP 14C (incorporated by reference as specified in § 250.198). 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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 67 FR 51760, Aug. 9, 2002; 70 FR 41583, July 19, 2005; 72 FR 12096, Mar. 15, 2007; 72 FR 25201, May 4, 2007]

§ 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 pressure 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, as amended at 72 FR 25201, May 4, 2007]

§ 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 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 must comply with section A7 of API RP 14C (incorporated by reference as specified in § 250.198). 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; 67 FR 51760, Aug. 9, 2002; 72 FR 25201, May 4, 2007]

§ 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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 72 FR 25201, May 4, 2007]

§ 250.1006 How must I decommission and take out of service a DOI pipeline?

(a) The requirements for decommissioning pipelines are listed in § 250.1750 through § 250.1754.

(b) The table in this section lists the requirements if you take a DOI pipeline out of service:

If you have the pipeline out of service for:	Then you must:
(1) 1 year or less	Isolate the pipeline with a blind flange or a closed block valve at each end of the pipeline.
(2) More than 1 year but less than 5 years.	Flush and fill the pipeline with inhibited seawater.
(3) 5 or more years	Decommission the pipeline according to §§ 250.1750–250.1754.

[67 FR 35405, May 17, 2002]

§ 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) A description of any additional design precautions you took to enable the pipeline to withstand the effects of water currents, storm or ice scouring, soft bottoms, mudslides, earthquakes, permafrost, and other environmental factors.

(i) If you propose to use unbonded flexible pipe, your application must include:

(A) The manufacturer's design specification sheet;

(B) The design pressure (psi);

(C) An identification of the design standards you used; and

(D) A review by a third-party independent verification agent (IVA) according to API Spec 17J (incorporated by reference as specified in § 250.198), if applicable.

(ii) If you propose to use one or more pipeline risers for a tension leg platform or other floating platform, your application must include:

(A) The design fatigue life of the riser, with calculations, and the fatigue point at which you would replace the riser;

(B) The results of your vortex-induced vibration (VIV) analysis;

(C) An identification of the design standards you used; and

(D) A description of any necessary mitigation measures such as the use of helical strakes or anchoring devices.

(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.

[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; 67 FR 35406, May 17, 2002; 70 FR 41583, July 19, 2005; 72 FR 25201, May 4, 2007; 73 FR 64548, Oct. 30, 2008]

§ 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 must notify the Regional Supervisor before the repair of any pipeline or as soon as practicable. Your notification must be accompanied by payment of the service fee listed in § 250.125. You must submit a detailed report of the repair of a pipeline or pipeline component to the Regional Supervisor within 30 days after the completion of the repairs. In the report you must 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; 71 FR 40912, July 19, 2006]

§ 250.1009 Requirements to obtain pipeline right-of-way grants.

(a) 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.

(b) 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.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003]

§ 250.1010 General requirements for pipeline right-of-way holders.

An applicant, by accepting a right-of-way grant, agrees to comply with the following requirements:

(a) The right-of-way holder shall comply with applicable laws and regulations and the terms of the grant.

(b) 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.

(c) 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 right-of-way holder how to protect it.

(d) 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.

(e) 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.

(f)(1) 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.

(2) Unless otherwise exempted by FERC pursuant to 43 U.S.C. 1334(f)(2), the holder shall—

(i) Provide open and nondiscriminatory access to a right-of-way pipeline to both owner and nonowner shippers, and

(ii) 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.

(g) 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.

(h) 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 § 250.1019 of this part.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 72 FR 25201, May 4, 2007]

§ 250.1011 Bond requirements for pipeline right-of-way holders.

(a) When you apply for, or are the holder of, a right-of-way, you must:

(1) 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

(2) Provide additional security if the Regional Director determines that a bond in excess of $300,000 is needed.

(b) For the purpose of this paragraph, there are three areas:

(1) The Gulf of Mexico and the area offshore the Atlantic Coast;

(2) The areas offshore the Pacific Coast States of California, Oregon, Washington, and Hawaii; and

(3) The area offshore the Coast of Alaska.

(c) 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.

(d) 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.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 72 FR 25201, May 4, 2007]

§ 250.1012 Required payments for pipeline right-of-way holders.

(a) You must pay MMS an annual rental of $15 for each statute mile, or part of a statute mile, of the OCS that your pipeline right-of-way crosses.

(b) This paragraph applies to you if you obtain a pipeline right-of-way that includes a site for an accessory to the pipeline, including but not limited to a platform. This paragraph also applies if you apply to modify a right-of-way to change the site footprint. In either case, you must pay the amounts shown in the following table.

If...	Then...
(1) Your accessory site is located in water depths of less than 200 meters;	You must pay a rental of $5 per acre per year with a minimum of $450 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other facilities and devices associated with the accessory.
(2) Your accessory site is located in water depths of 200 meters or greater;	You must pay a rental of $7.50 per acre per year with a minimum of $675 per year. The area subject to annual rental includes the areal extent of anchor chains, pipeline risers, and other facilities and devices associated with the accessory.

(c) If you hold a pipeline right-of-way that includes a site for an accessory to your pipeline and you are not covered by paragraph (b) of this section, then you must pay MMS an annual rental of $75 for use of the affected area.

(d) You may make the rental payments required by paragraphs (a), (b)(1), (b)(2), and (c) of this section on an annual basis, for a 5-year period, or for multiples of 5 years. You must make the first payment at the time you submit the pipeline right-of-way application. You must make all subsequent payments before the respective time periods begin.

(e) *Late payments*. An interest charge will be assessed on unpaid and underpaid amounts from the date the amounts are due, in accordance with the provisions found in 30 CFR 218.54. If you fail to make a payment that is late after written notice from MMS, MMS may initiate cancellation of the right-of-use grant and easement under 30 CFR 250.1013.

[68 FR 69312, Dec. 12, 2003, as amended at 69 FR 29433, May 24, 2004]

§ 250.1013 Grounds for forfeiture of pipeline right-of-way grants.

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.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003]

§ 250.1014 When pipeline right-of-way grants expire.

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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003]

§ 250.1015 Applications for pipeline right-of-way grants.

(a) You must submit an original and three copies of an application for a new or modified pipeline ROW 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 ROW grant. If the ROW 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 §250.1012 of this subpart, as well as the service fees listed in §250.125 of this part for a pipeline ROW grant to install a new pipeline, or to convert an existing lease term pipeline into a ROW pipeline. An application to modify an approved ROW grant must be accompanied by the additional rental required under §250.1012 if applicable. You must file a separate application for each ROW.

(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.

(e) Notwithstanding the provisions of paragraph (a) of this section, the requirements to pay filing fees under that paragraph are suspended until January 3, 2006.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 70 FR 49876, Aug. 25, 2005; 70 FR 61893, Oct. 27, 2005]

§ 250.1016 Granting pipeline rights-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 §250.1015(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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 72 FR 25201, May 4, 2007]

§ 250.1017 Requirements for construction under pipeline right-of-way grants.

(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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003]

§ 250.1018 Assignment of pipeline right-of-way grants.

(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 must be accompanied by the same showing of qualifications of the assignees as is required of an applicant for a ROW in § 250.1015 of this subpart and must be supported by a statement that the assignee agrees to comply with and to be bound by the terms and conditions of the ROW grant. The assignee must satisfy the bonding requirements in § 250.1011 of this subpart. No transfer will be recognized unless and until it is first approved, in writing, by the Regional Supervisor. The assignee must pay the service fee listed in § 250.125 of this part for a pipeline ROW assignment request.

(c) Notwithstanding the provisions of paragraph (b) of this section, the requirement to pay a filing fee under that paragraph is suspended until January 3, 2006.

[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. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 70 FR 49876, Aug. 25, 2005; 70 FR 61893, Oct. 27, 2005]

§ 250.1019 Relinquishment of pipeline right-of-way grants.

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 must contain those items addressed in §§ 250.1751 and 250.1752 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 § 250.1010(h) of this part.

[53 FR 10690, Apr. 1, 1988. Redesignated and amended at 63 FR 29479, 29486, May 29, 1998; 67 FR 35406, May 17, 2002. Further redesignated and amended at 68 FR 69311, 69312, Dec. 12, 2003; 72 FR 25201, May 4, 2007]

Subpart K—Oil and Gas Production Requirements

SOURCE: 75 FR 20289, Apr. 19, 2010, unless otherwise noted.

GENERAL

§ 250.1150 What are the general reservoir production requirements?

You must produce wells and reservoirs at rates that provide for economic development while maximizing ultimate recovery and without adversely affecting correlative rights.

WELL TESTS AND SURVEYS

§ 250.1151 How often must I conduct well production tests?

(a) You must conduct well production tests as shown in the following table:

You must conduct:	And you must submit to the Regional Supervisor:
(1) A well-flow potential test on all new, recompleted, or reworked well completions within 30 days of the date of first continuous production.	Form MMS–126, Well Potential Test Report, along with the supporting data as listed in the table in § 250.1167, within 15 days after the end of the test period.
(2) At least one well test during a calendar half-year for each producing completion.	Results on Form MMS–128, Semiannual Well Test Report, of the most recent well test obtained. This must be submitted within 45 days after the end of the calendar half-year.

(b) You may request an extension from the Regional Supervisor if you cannot submit the results of a semi-annual well test within the specified time.

(c) You must submit to the Regional Supervisor an original and two copies of the appropriate form required by paragraph (a) of this section; one of the copies of the form must be a public information copy in accordance with §§ 250.186 and 250.197, and marked ''Public Information.'' You must submit two copies of the supporting information as listed in the table in § 250.1167 with form MMS–126.

§ 250.1152 How do I conduct well tests?

(a) When you conduct well tests you must:

(1) Recover fluid from the well completion equivalent to the amount of fluid introduced into the formation during completion, recompletion, reworking, or treatment operations before you start a well test;

(2) Produce the well completion under stabilized rate conditions for at least 6 consecutive hours before beginning the test period;

(3) Conduct the test for at least 4 consecutive hours;

(4) Adjust measured gas volumes to the standard conditions of 14.73 pounds per square inch absolute (psia) and 60 °F for all tests; and

(5) Use measured specific gravity values to calculate gas volumes.

(b) You may request approval from the Regional Supervisor to conduct a well test using alternative procedures if you can demonstrate test reliability under those procedures.

(c) The Regional Supervisor may also require you to conduct the following tests and complete them within a specified time period:

(1) A retest or a prolonged test of a well completion if it is determined to be necessary for the proper establishment of a Maximum Production Rate (MPR) or a Maximum Efficient Rate (MER); and

(2) A multipoint back-pressure test to determine the theoretical open-flow potential of a gas well.

(d) An MMS representative may witness any well test. Upon request, you must provide advance notice to the Regional Supervisor of the times and dates of well tests.

§ 250.1153 When must I conduct a static bottomhole pressure survey?

(a) You must conduct a static bottomhole pressure survey under the following conditions:

If you have . . .	Then you must conduct . . .
(1) A new producing reservoir	A static bottomhole pressure survey within 90 days after the date of first continuous production.
(2) A reservoir with three or more producing completions	Annual static bottomhole pressure surveys in a sufficient number of key wells to establish an average reservoir pressure. The Regional Supervisor may require that bottomhole pressure surveys be performed on specific wells.

(b) Your bottomhole pressure survey must meet the following requirements:

(1) You must shut-in the well for a minimum period of 4 hours to ensure stabilized conditions; and

(2) The bottomhole pressure survey must consist of a pressure measurement at mid-perforation, and pressure measurements and gradient information for at least four gradient stops coming out of the hole.

(c) You must submit to the Regional Supervisor the results of all static bottomhole pressure surveys on Form MMS–140, Bottomhole Pressure Survey Report, within 60 days after the date of the survey.

(d) The Regional Supervisor may grant a departure from the requirement to run a static bottomhole pressure survey. To request a departure, you must submit a justification, along with Form MMS–140, Bottomhole Pressure Survey Report, showing a calculated bottomhole pressure or any measured data.

CLASSIFYING RESERVOIRS

§ 250.1154 How do I determine if my reservoir is sensitive?

(a) You must determine whether each reservoir is sensitive. You must classify the reservoir as sensitive if:

(1) Under initial conditions it is an oil reservoir with an associated gas cap;

(2) At any time there are near-critical fluids; or

(3) The reservoir is undergoing enhanced recovery.

(b) For the purposes of this subpart, near-critical fluids are:

(1) Those fluids that occur in high temperature, high-pressure reservoirs where it is not possible to define the liquid-gas contact; or

(2) Fluids in reservoirs that are near bubble point or dew point conditions.

(c) The Regional Supervisor may reclassify a reservoir when available information warrants reclassification.

(d) If available information indicates that a reservoir previously classified as non-sensitive is now sensitive, you must submit a request to the Regional Supervisor to reclassify the reservoir. You must include supporting information, as listed in the table in § 250.1167, with your request.

(e) If information indicates that a reservoir previously classified as sensitive is now non-sensitive, you may submit a request to the Regional Supervisor to reclassify the reservoir. You must include supporting information, as listed in the table in § 250.1167, with your request.

§ 250.1155 What information must I submit for sensitive reservoirs?

You must submit to the Regional Supervisor an original and two copies of Form MMS–127; one of the copies must be a public information copy in accordance with §§ 250.186 and 250.197, and marked ''Public Information.'' You must also submit two copies of the supporting information, as listed in the table in § 250.1167. You must submit this information:

(a) Within 45 days after beginning production from the reservoir or discovering that it is sensitive;

(b) At least once during the calendar year, but you do not need to resubmit unrevised structure maps (§ 250.1167(a)(2)) or previously submitted well logs (§ 250.1167(c)(1));

(c) Within 45 days after you revise reservoir parameters; and

(d) Within 45 days after the Regional Supervisor classifies the reservoir as sensitive under § 250.1154(c).

APPROVALS PRIOR TO PRODUCTION

§ 250.1156 What steps must I take to receive approval to produce within 500 feet of a unit or lease line?

(a) You must obtain approval from the Regional Supervisor before you start producing from a reservoir within a well that has any portion of the completed interval less than 500 feet from a unit or lease line. Submit to MMS the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request. The Regional Supervisor will determine whether approval of your request will maximize ultimate recovery, avoid the waste of natural resources, or protect correlative rights. You do not need to obtain approval if the adjacent leases or units have the same unit, lease (record title and operating rights), and royalty interests as the lease or unit you plan to produce. You do not need to obtain approval if the adjacent block is unleased.

(b) You must notify the operator(s) of adjacent property(ies) that are within 500 feet of the completion, if the adjacent acreage is a leased block in the Federal OCS. You must provide the Regional Supervisor proof of the date of the notification. The operators of the adjacent properties have 30 days after receiving the notification to provide the Regional Supervisor letters of acceptance or objection. If an adjacent operator does not respond within 30 days, the Regional Supervisor will presume there are no objections and proceed with a decision. The notification must include:

(1) The well name;

(2) The rectangular coordinates (x, y) of the location of the top and bottom of the completion or target completion referenced to the North American Datum 1983, and the subsea depths of the top and bottom of the completion or target completion;

(3) The distance from the completion or target completion to the unit or lease line at its nearest point; and

(4) A statement indicating whether or not it will be a high-capacity completion having a perforated or open hole interval greater than 150 feet measured depth.

§ 250.1157 How do I receive approval to produce gas-cap gas from an oil reservoir with an associated gas cap?

(a) You must request and receive approval from the Regional Supervisor:

(1) Before producing gas-cap gas from each completion in an oil reservoir that is known to have an associated gas cap.

(2) To continue production from a well if the oil reservoir is not initially known to have an associated gas cap, but the oil well begins to show characteristics of a gas well.

(b) For either request, you must submit the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request.

(c) The Regional Supervisor will determine whether your request maximizes ultimate recovery.

§ 250.1158 How do I receive approval to downhole commingle hydrocarbons?

(a) Before you perforate a well, you must request and receive approval from the Regional Supervisor to commingle hydrocarbons produced from multiple reservoirs within a common wellbore. The Regional Supervisor will determine whether your request maximizes ultimate recovery. You must include the service fee listed in § 250.125, according to the instructions in § 250.126, and the supporting information, as listed in the table in § 250.1167, with your request.

(b) If one or more of the reservoirs proposed for commingling is a competitive reservoir, you must notify the operators of all leases that contain the reservoir that you intend to downhole commingle the reservoirs. Your request for approval of downhole commingling must include proof of the date of this notification. The notified operators have 30 days after notification to provide the Regional Supervisor with letters of acceptance or objection. If the notified operators do not respond within the specified period, the Regional Supervisor will assume the operators do not object and proceed with a decision.

PRODUCTION RATES

§ 250.1159 May the Regional Supervisor limit my well or reservoir production rates?

(a) The Regional Supervisor may set a Maximum Production Rate (MPR) for a producing well completion, or set a Maximum Efficient Rate (MER) for a reservoir, or both, if the Regional Supervisor determines that an excessive production rate could harm ultimate recovery. An MPR or MER will be based on well tests and any limitations imposed by well and surface equipment, sand production, reservoir sensitivity, gas-oil and water-oil ratios, location of perforated intervals, and prudent operating practices.

(b) If the Regional Supervisor sets an MPR for a producing well completion and/or an MER for a reservoir, you may not exceed those rates except due to normal variations and fluctuations in production rates as set by the Regional Supervisor.

FLARING, VENTING, AND BURNING HYDROCARBONS

§ 250.1160 When may I flare or vent gas?

(a) You must request and receive approval from the Regional Supervisor to flare or vent natural gas at your facility, except in the following situations:

Condition	Additional requirements
(1) When the gas is lease use gas (produced natural gas which is used on or for the benefit of lease operations such as gas used to operate production facilities) or is used as an additive necessary to burn waste products, such as H_2S.	The volume of gas flared or vented may not exceed the amount necessary for its intended purpose. Burning waste products may require approval under other regulations.
(2) During the restart of a facility that was shut in because of weather conditions, such as a hurricane.	Flaring or venting may not exceed 48 cumulative hours without Regional Supervisor approval.

Condition	Additional requirements
(3) During the blow down of transportation pipelines downstream of the royalty meter.	(i) You must report the location, time, flare/vent volume, and reason for flaring/venting to the Regional Supervisor in writing within 72 hours after the incident is over. (ii) Additional approval may be required under subparts H and J of this part.
(4) During the unloading or cleaning of a well, drill-stem testing, production testing, other well-evaluation testing, or the necessary blow down to perform these procedures.	You may not exceed 48 cumulative hours of flaring or venting per unloading or cleaning or testing operation on a single completion without Regional Supervisor approval.
(5) When properly working equipment yields flash gas (natural gas released from liquid hydrocarbons as a result of a decrease in pressure, an increase in temperature, or both) from storage vessels or other low-pressure production vessels, and you cannot economically recover this flash gas.	You may not flare or vent more than an average of 50 MCF per day during any calendar month without Regional Supervisor approval.
(6) When the equipment works properly but there is a temporary upset condition, such as a hydrate or paraffin plug.	(i) For oil-well gas and gas-well flash gas (natural gas released from condensate as a result of a decrease in pressure, an increase in temperature, or both), you may not exceed 48 continuous hours of flaring or venting without Regional Supervisor approval. (ii) For primary gas-well gas (natural gas from a gas well completion that is at or near its wellhead pressure; this does not include flash gas), you may not exceed 2 continuous hours of flaring or venting without Regional Supervisor approval. (iii) You may not exceed 144 cumulative hours of flaring or venting during a calendar month without Regional Supervisor approval.
(7) When equipment fails to work properly, during equipment maintenance and repair, or when you must relieve system pressures.	(i) For oil-well gas and gas-well flash gas, you may not exceed 48 continuous hours of flaring or venting without Regional Supervisor approval. (ii) For primary gas-well gas, you may not exceed 2 continuous hours of flaring or venting without Regional Supervisor approval. (iii) You may not exceed 144 cumulative hours of flaring or venting during a calendar month without Regional Supervisor approval. (iv) The continuous and cumulative hours allowed under this paragraph may be counted separately from the hours under paragraph (a)(6) of this section.

(b) Regardless of the requirements in paragraph (a) of this section, you must not flare or vent gas over the volume approved in your Development Operations Coordination Document (DOCD) or your Development and Production Plan (DPP).

(c) The Regional Supervisor may establish alternative approval procedures to cover situations when you cannot contact the MMS office, such as during non-office hours.

(d) The Regional Supervisor may specify a volume limit, or a shorter time limit than specified elsewhere in this part, in order to prevent air quality degradation or loss of reserves.

(e) If you flare or vent gas without the required approval, or if the Regional Supervisor determines that you were negligent or could have avoided flaring or venting the gas, the hydrocarbons will be considered avoidably lost or wasted. You must pay royalties on the loss or waste, according to part 202 of this title. You must value any gas or liquid hydrocarbons avoidably lost or wasted under the provisions of part 206 of this title.

(f) Fugitive emissions from valves, fittings, flanges, pressure relief valves or similar components do not require approval under this subpart unless specifically required by the Regional Supervisor.

§ 250.1161 When may I flare or vent gas for extended periods of time?

You must request and receive approval from the Regional Supervisor to flare or vent gas for an extended period of time. The Regional Supervisor will specify the approved period of time, which will not exceed 1 year. The Regional Supervisor may deny your request if it does not ensure the conservation of natural resources or is not consistent with national interests relating to development and production of minerals of the OCS. The Regional Supervisor may approve your request for one of the following reasons:

(a) You initiated an action which, when completed, will eliminate flaring and venting; or

(b) You submit to the Regional Supervisor an evaluation supported by engineering, geologic, and economic data indicating that the oil and gas produced from the well(s) will not economically support the facilities necessary to sell the gas or to use the gas on or for the benefit of the lease.

§ 250.1162 When may I burn produced liquid hydrocarbons?

(a) You must request and receive approval from the Regional Supervisor to burn any produced liquid hydrocarbons. The Regional Supervisor may allow you to burn liquid hydrocarbons if you demonstrate that transporting them to market or re-injecting them is not technically feasible or poses a significant risk of harm to offshore personnel or the environment.

(b) If you burn liquid hydrocarbons without the required approval, or if the Regional Supervisor determines that you were negligent or could have avoided burning liquid hydrocarbons, the hydrocarbons will be considered avoidably lost or wasted. You must pay royalties on the loss or waste, according to part 202 of this title. You must value any liquid hydrocarbons avoidably lost or wasted under the provisions of part 206 of this title.

§ 250.1163 How must I measure gas flaring or venting volumes and liquid hydrocarbon burning volumes, and what records must I maintain?

(a) If your facility processes more than an average of 2,000 bopd during May 2010, you must install flare/vent meters within 180 days after May 2010. If your facility processes more than an average of 2,000 bopd during a calendar month after May 2010, you must install flare/vent meters within 120 days after the end of the month in which the average amount of oil processed exceeds 2,000 bopd.

(1) You must notify the Regional Supervisor when your facility begins to process more than an average of 2,000 bopd in a calendar month;

(2) The flare/vent meters must measure all flared and vented gas within 5 percent accuracy;

(3) You must calibrate the meters regularly, in accordance with the manufacturer's recommendation, or at least once every year, whichever is shorter; and

(4) You must use and maintain the flare/vent meters for the life of the facility.

(b) You must report all hydrocarbons produced from a well completion, including all gas flared, gas vented, and liquid hydrocarbons burned, to Minerals Revenue Management on Form MMS–4054 (Oil and Gas Operations Report), in accordance with § 210.102 of this title.

(1) You must report the amount of gas flared and the amount of gas vented separately.

(2) You may classify and report gas used to operate equipment on the lease, such as gas used to power engines, instrument gas, and gas used to maintain pilot lights, as lease use gas.

(3) If flare/vent meters are required at one or more of your facilities, you must report the amount of gas flared and vented at each of those facilities separately from those facilities that do not require meters and separately from other facilities with meters.

(4) If flare/vent meters are not required at your facility:

(i) You may report the gas flared and vented on a lease or unit basis. Gas flared and vented from multiple facilities on a single lease or unit may be reported together.

(ii) If you choose to install meters, you may report the gas volume flared and vented according to the method specified in paragraph (b)(3) of this section.

(c) You must prepare and maintain records detailing gas flaring, gas venting, and liquid hydrocarbon burning for each facility for 6 years.

(1) You must maintain these records on the facility for at least the first 2 years and have them available for inspection by MMS representatives.

(2) After 2 years, you must maintain the records, allow MMS representatives to inspect the records upon request and provide copies to the Regional Supervisor upon request, but are not required to keep them on the facility.

(3) The records must include, at a minimum:

(i) Daily volumes of gas flared, gas vented, and liquid hydrocarbons burned;

(ii) Number of hours of gas flaring, gas venting, and liquid hydrocarbon burning, on a daily and monthly cumulative basis;

(iii) A list of the wells contributing to gas flaring, gas venting, and liquid hydrocarbon burning, along with gas-oil ratio data;

(iv) Reasons for gas flaring, gas venting, and liquid hydrocarbon burning; and

(v) Documentation of all required approvals.

(d) If your facility is required to have flare/vent meters:

(1) You must maintain the meter recordings for 6 years.

(i) You must keep these recordings on the facility for 2 years and have them available for inspection by MMS representatives.

(ii) After 2 years, you must maintain the recordings, allow MMS representatives to inspect the recordings upon request and provide copies to the Regional Supervisor upon request, but are not required to keep them on the facility.

(iii) These recordings must include the begin times, end times, and volumes for all flaring and venting incidents.

(2) You must maintain flare/vent meter calibration and maintenance records on the facility for 2 years.

(e) If your flaring or venting of gas, or burning of liquid hydrocarbons, required written or oral approval, you must submit documentation to the Regional Supervisor summarizing the location, dates, number of hours, and volumes of gas flared, gas vented, and liquid hydrocarbons burned under the approval.

§ 250.1164 What are the requirements for flaring or venting gas containing H_2S?

(a) You may 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 atmosphere concentration of H_2S of 20 ppm or higher anywhere on the platform.

(b) You may flare gas containing H_2S only if you meet the requirements of §§ 250.1160, 250.1161, 250.1163, and the following additional requirements:

(1) For safety or air pollution prevention purposes, the Regional Supervisor may further restrict the flaring of gas containing H_2S. The Regional Supervisor will use information provided in the lessee's H_2S Contingency Plan (§ 250.490(f)), Exploration Plan, DPP, DOCD, and associated documents to determine the need for restrictions; and

(2) 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 you to conduct an air quality modeling analysis, under § 250.303, to determine the potential effect of facility emissions. The Regional Supervisor may require monitoring and reporting, or may restrict or prohibit flaring, under §§ 250.303 and 250.304.

(c) The Regional Supervisor may require you to submit monthly reports of flared and vented gas containing H_2S. Each report must contain, on a daily basis:

(1) The volume and duration of each flaring and venting occurrence;

(2) H_2S concentration in the flared or vented gas; and

(3) The calculated amount of SO_2 emitted.

OTHER REQUIREMENTS

§ 250.1165 What must I do for enhanced recovery operations?

(a) You must promptly initiate enhanced oil and gas recovery operations for all reservoirs where these operations would result in an increase in ultimate recovery of oil or gas under sound engineering and economic principles.

(b) Before initiating enhanced recovery operations, you must submit a proposed plan to the Regional Supervisor and receive approval for pressure maintenance, secondary or tertiary recovery, cycling, and similar recovery operations intended to increase the ultimate recovery of oil and gas from a reservoir. The proposed plan must include, for each project reservoir, a geologic and engineering overview, Form

MMS–127 and supporting data as required in § 250.1167, and any additional information required by the Regional Supervisor.

(c) You must report to Minerals Revenue Management the volumes of oil, gas, or other substances injected, produced, or produced for a second time under § 210.102 of this title.

§ 250.1166 What additional reporting is required for developments in the Alaska OCS Region?

(a) For any development in the Alaska OCS Region, you must submit an annual reservoir management report to the Regional Supervisor. The report must contain information detailing the activities performed during the previous year and planned for the upcoming year that will:

(1) Provide for the prevention of waste;

(2) Provide for the protection of correlative rights; and

(3) Maximize ultimate recovery of oil and gas.

(b) If your development is jointly regulated by MMS and the State of Alaska, MMS and the Alaska Oil and Gas Conservation Commission will jointly determine appropriate reporting requirements to minimize or eliminate duplicate reporting requirements.

(c) Every time you are required to submit Form MMS–127 under § 250.1155, you must request an MER for each producing sensitive reservoir in the Alaska OCS Region, unless otherwise instructed by the Regional Supervisor.

§ 250.1167 What information must I submit with forms and for approvals?

You must submit the supporting information listed in the following table with the forms identified in columns 1 and 2 and for the approvals required under this subpart identified in columns 3 through 6:

	WPT MMS–126 (2 copies)	SRI MMS–127 (2 copies)	Gas cap production	Downhole commingling	Reservoir reclassification	Production within 500-ft of a unit or lease line
(a) Maps:						
(1) Base map with surface, bottomhole, and completion locations with respect to the unit or lease line and the orientation of representative seismic lines or cross-sections	....	....	√	√	....	√
(2) Structure maps with penetration point and subsea depth for each well penetrating the reservoirs, highlighting subject wells; reservoir boundaries; and original and current fluid levels	√	√	√	√	√	√
(3) Net sand isopach with total net sand penetrated for each well, identified at the penetration point	....	*	√	√		
(4) Net hydrocarbon isopach with net feet of pay for each well, identified at the penetration point	....	*	√	√		
(b) Seismic data:						
(1) Representative seismic lines, including strike and dip lines that confirm the structure; indicate polarity	....	....	√	√	....	√
(2) Amplitude extraction of seismic horizon, if applicable	....	....	√	√	√	√
(c) Logs:						
(1) Well log sections with tops and bottoms of the reservoir(s) and proposed or existing perforations	√	√	√	√	√	√
(2) Structural cross-sections showing the subject well and nearby wells	....	....	√	√	√	*
(d) Engineering data:						
(1) Estimated recoverable reserves for each well completion in the reservoir; total recoverable reserves for each reservoir; method of calculation; reservoir parameters used in volumetric and decline curve analysis	....	√	†	†	....	√
(2) Well schematics showing current and proposed conditions	....	....	√	√	....	√

	WPT MMS–126 (2 copies)	SRI MMS–127 (2 copies)	Gas cap production	Downhole commingling	Reservoir reclassification	Production within 500-ft of a unit or lease line
(3) The drive mechanism of each reservoir	....	√	√	√	√	√
(4) Pressure data, by date, and whether they are estimated or measured	....	....	√	√	√	
(5) Production data and decline curve analysis indicative of the reservoir performance	....	....	√	√	√	
(6) Reservoir simulation with the reservoir parameters used, history matches, and prediction runs (include proposed development scenario)	....	....	*	*	*	*
(e) General information:						
(1) Detailed economic analysis	....	....	*	*		
(2) Reservoir name and whether or not it is competitive as defined under § 250.105	....	√	√	√	√	√
(3) Operator name, lessee name(s), block, lease number, royalty rate, and unit number (if applicable) of all relevant leases	....	....	√	√	....	√
(4) Geologic overview of project	....	....	√	√	√	√
(5) Explanation of why the proposed completion scenario will maximize ultimate recovery	....	....	√	√	....	√
(6) List of all wells in subject reservoirs that have ever produced or been used for injection	....	....	√	√	√	√

√ Required.

† Each Gas Cap Production request and Downhole Commingling request must include the estimated recoverable reserves for (1) the case where your proposed production scenario is approved, and (2) the case where your proposed production scenario is denied.

* Additional items the Regional Supervisor may request.

Note: All maps must be at a standard scale and show lease and unit lines. The Regional Supervisor may waive submittal of some of the required data on a case-by-case basis.

(f) Depending on the type of approval requested, you must submit the appropriate payment of the service fee(s) listed in § 250.125, according to the instructions in § 250.126.

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
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2. What are the requirements for liquid hydrocarbon royalty meters?	§ 250.1202(b)
3. What are the requirements for run tickets?	§ 250.1202(c)
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Frequently asked questions	CFR citation
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)).

Compositional Analysis—separating mixtures into identifiable components expressed in mole percent.

Force majeure event—an event beyond your control such as war, act of terrorism, crime, or act of nature which prevents you from operating the wells and meters on your OCS facility.

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 and/or unit participating areas prior to royalty measurement.

Temperature base—the temperature at which gas and liquid hydrocarbon volumes and quality are reported. The standard temperature base is 60 °F.

Verification/Calibration—testing and correcting, if necessary, a measuring device to ensure compliance with industry accepted, manufacturer's recommended, or regulatory required standard of accuracy.

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; 73 FR 20171, Apr. 15, 2008; 74 FR 40073, Aug. 11, 2009]

§ 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 any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant gas measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity as shown in the following table.

Application type	Actions
(i) Simple applications	Applications to temporarily reroute production (for a duration not to exceed six months); Production tests prior to pipeline construction; Departures related to meter proving, well testing, or sampling frequency.
(ii) Complex applications	Creation of new facility measurement points (FMPs); Association of leases or units with existing FMPs; Inclusion of production from additional structures; Meter updates which add buy-back gas meters or pigging meters; Other applications which request deviations from the approved allocation 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. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter, 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 250.198; 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 operating allocation meters monthly if they measure 50 or more barrels per day per meter the previous month. When a force majeure event precludes the required monthly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved monthly thereafter; or

(4) Prove operating allocation meters quarterly if they measure less than 50 barrels per day per meter the previous month. When a force majeure event precludes the required quarterly meter proving, meters must be proved within 15 days after being returned to service. The meters must be proved quarterly thereafter;

(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; 71 FR 40912, July 19, 2006; 72 FR 25201, May 4, 2007; 73 FR 20171, Apr. 15, 2008; 74 FR 40073, Aug. 11, 2009]

§ 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 any changes to the previously-approved measurement and/or allocation procedures. Your application (which may also include any relevant liquid hydrocarbon measurement and surface commingling requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

(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) Verify/calibrate operating meters monthly, but do not exceed 42 days between verifications/calibrations. When a force majeure event precludes the required monthly meter verification/calibration, meters must be verified/calibrated within 15 days after being returned to service. The meters must be verified/calibrated monthly thereafter, but do not exceed 42 days between meter verifications/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; 71 FR 40912, July 19, 2006; 74 FR 40073, Aug. 11, 2009]

§ 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 any changes to the previously approved commingling procedures. Your application (which may also include any relevant liquid hydrocarbon and gas measurement requests) must be accompanied by payment of the service fee listed in § 250.125. The service fees are divided into two levels based on complexity, see table in § 250.1202(a)(1).

(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 60 days unless the Regional Supervisor approves a different frequency. When a force majeure event precludes the required well test within the prescribed 60 day period (or other frequency approved by the Regional Supervisor), wells must be tested within 15 days after being returned to production. Thereafter, well tests must be conducted at least once every 60 days (or other frequency approved by the Regional Supervisor);

(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; 71 FR 40913, July 19, 2006; 73 FR 20171, Apr. 15, 2008; 74 FR 40073, Aug. 11, 2009]

§ 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 of a reasonably delineated and productive reservoir if unitized operations are necessary to:

(1) Prevent waste;

(2) Conserve natural resources; or

(3) Protect correlative rights, including Federal royalty interests.

(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 common to two or more leases. 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; 73 FR 20172, Apr. 15, 2008]

§ 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.

(d) You must pay the service fee listed in § 250.125 of this part with your request for a voluntary unitization proposal or the expansion of a previously approved voluntary unit to include additional acreage. Additionally, you must pay the service fee listed in § 250.125 with your request for unitization revision.

[62 FR 5331, Feb. 5, 1997. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 70 FR 49876, Aug. 25, 2005]

§ 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

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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.

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.

[62 FR 42668, Aug. 8, 1997. Redesignated at 63 FR 29479, May 29, 1998, as amended at 71 FR 23864, Apr. 25, 2006]

§ 250.1403 What is the maximum civil penalty?

The maximum civil penalty is $35,000 per day per violation.

[72 FR 8899, Feb. 28, 2007]

§ 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—Well Control and Production Safety Training

SOURCE: 65 FR 49490, Aug. 14, 2000, unless otherwise noted.

§ 250.1500 Definitions.

Terms used in this subpart have the following meaning:

Contractor and contract personnel mean anyone, other than an employee of the lessee, performing well control or production safety duties for the lessee.

Employee means direct employees of the lessees who are assigned well control or production safety duties.

I or *you* means the lessee engaged in oil, gas, or sulphur operations in the Outer Continental Shelf (OCS).

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 an owner of operating rights for that lease and the MMS-approved assignee of that lease.

Periodic means occurring or recurring at regular intervals. Each lessee must specify the intervals for periodic training and periodic assessment of training needs in their training programs.

Production safety includes measures, practices, procedures, and equipment to ensure safe, accident-free, and pollution-free production operations, as well as installation, repair, testing, maintenance, and operation of surface and subsurface safety equipment. Production operations include, but are not limited to, separation, dehydration, compression, sweetening, and metering operations.

Well control means drilling, well completion, well workover, and well servicing operations. For purposes of this subpart, well completion/well workover means those operations following the drilling of a well that are intended to establish or restore production to a well. It includes small tubing operations but does not include well servicing. Well servicing means snubbing, coil tubing, and wireline operations.

[65 FR 49490, Aug. 14, 2000, as amended at 74 FR 40073, Aug. 11, 2009]

§ 250.1501 What is the goal of my training program?

The goal of your training program must be safe and clean OCS operations. To accomplish this, you must ensure that your employees and contract personnel engaged in well control or production safety operations understand and can properly perform their duties.

§ 250.1503 What are my general responsibilities for training?

(a) You must establish and implement a training program so that all of your employees are trained to competently perform their assigned well control and production safety duties. You must verify that your employees understand and can perform the assigned well control or production safety duties.

(b) You must have a training plan that specifies the type, method(s), length, frequency, and content of the training for your employees. Your training plan must specify the method(s) of verifying employee understanding and performance. This plan must include at least the following information:

(1) Procedures for training employees in well control or production safety practices;

(2) Procedures for evaluating the training programs of your contractors;

(3) Procedures for verifying that all employees and contractor personnel engaged in well control or production safety operations can perform their assigned duties;

(4) Procedures for assessing the training needs of your employees on a periodic basis;

(5) Recordkeeping and documentation procedures; and

(6) Internal audit procedures.

(c) Upon request of the District Manager or Regional Supervisor, you must provide:

(1) Copies of training documentation for personnel involved in well control or production safety operations during the past 5 years; and

(2) A copy of your training plan.

§ 250.1504 May I use alternative training methods?

You may use alternative training methods. These methods may include computer-based learning, films, or their equivalents. This training should be reinforced by appropriate demonstrations and ''hands-on'' training. Alternative training methods must be conducted according to, and meet the objectives of, your training plan.

§ 250.1505 Where may I get training for my employees?

You may get training from any source that meets the requirements of your training plan.

§ 250.1506 How often must I train my employees?

You determine the frequency of the training you provide your employees. You must do all of the following:

(a) Provide periodic training to ensure that employees maintain understanding of, and competency in, well control or production safety practices;

(b) Establish procedures to verify adequate retention of the knowledge and skills that employees need to perform their assigned well control or production safety duties; and

(c) Ensure that your contractors' training programs provide for periodic training and verification of well control or production safety knowledge and skills.

§ 250.1507 How will MMS measure training results?

MMS may periodically assess your training program, using one or more of the methods in this section.

(a) *Training system audit.* MMS or its authorized representative may conduct a training system audit at your office. The training system audit will compare your training program against this subpart. You must be prepared to explain your overall training program and produce evidence to support your explanation.

(b) *Employee or contract personnel interviews.* MMS or its authorized representative may conduct interviews at either onshore or offshore locations to inquire about the types of training that were provided, when and where this training was conducted, and how effective the training was.

(c) *Employee or contract personnel testing.* MMS or its authorized representative may conduct testing at either onshore or offshore locations for the purpose of evaluating an individual's knowledge and skills in perfecting well control and production safety duties.

(d) *Hands-on production safety, simulator, or live well testing.* MMS or its authorized representative may conduct tests at either onshore or offshore locations. Tests will be designed to evaluate the competency of your employees or contract personnel in performing their assigned well control and production safety duties. You are responsible for the costs associated with this testing, excluding salary and travel costs for MMS personnel.

§ 250.1508 What must I do when MMS administers written or oral tests?

MMS or its authorized representative may test your employees or contract personnel at your worksite or at an onshore location. You and your contractors must:

(a) Allow MMS or its authorized representative to administer written or oral tests; and

(b) Identify personnel by current position, years of experience in present position, years of total oil field experience, and employer's name (e.g., operator, contractor, or sub-contractor company name).

§ 250.1509 What must I do when MMS administers or requires hands-on, simulator, or other types of testing?

If MMS or its authorized representative conducts, or requires you or your contractor to conduct hands-on, simulator, or other types of testing, you must:

(a) Allow MMS or its authorized representative to administer or witness the testing;

(b) Identify personnel by current position, years of experience in present position, years of total oil field experience, and employer's name (e.g., operator, contractor, or sub-contractor company name); and

(c) Pay for all costs associated with the testing, excluding salary and travel costs for MMS personnel.

§ 250.1510 What will MMS do if my training program does not comply with this subpart?

If MMS determines that your training program is not in compliance, we may initiate one or more of the following enforcement actions:

(a) Issue an Incident of Noncompliance (INC);

(b) Require you to revise and submit to MMS your training plan to address identified deficiencies;

(c) Assess civil/criminal penalties; or

(d) Initiate disqualification procedures.

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, I, J, M, N, O, and Q 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.

[53 FR 10690, Apr. 1, 1988. Redesignated at 63 FR 29479, May 29, 1998, as amended at 72 FR 25201, May 4, 2007]

§ 250.1603 Determination of sulphur deposit.

(a) Upon receipt of a written request from the lessee, the District Manager 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 250.490 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 § 250.490 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 § 250.109 through § 250.113 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 § 250.114 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.* All drilling units being used for drilling, well-completion, or well-workover operations that have both a traveling block and a crown block must be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device must be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check must be entered in the operations log.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 67 FR 51760, Aug. 9, 2002; 68 FR 8435, Feb. 20, 2003; 74 FR 46909, Sept. 14, 2009]

§ 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 Manager.

(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 Manager 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 Manager. The type of information to be collected and reported will be determined by the District Manager 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 §§ 250.211 through 250.228 and 250.241 through 250.262 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 Manager may require that additional surveys and soil borings be performed and the results submitted for review and evaluation by the District Manager 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.* Diesel-engine air intakes must be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote-operated manual or automatic-shutdown devices. Diesel engines that are not continuously attended must 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; 70 FR 51519, Aug. 30, 2005; 74 FR 46909, Sept. 14, 2009]

§ 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 Manager to determine specific operating requirements, field rules may be established for drilling, well completion, or well workover on the District Manager'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 Manager 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 Manager 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 Manager. 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 Manager, 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 Manager 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 Manager 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 Manager. 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. Accumulator regulators supplied by rig air that do not have a secondary source of pneumatic supply must 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 Manager;

(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 Manager.

(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.

[56 FR 32100, July 15, 1991. Redesignated at 63 FR 29479, May 29, 1998, as amended at 74 FR 46909, Sept. 14, 2009]

§ 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 Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(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 Manager. 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 Manager.

§ 250.1612 Well-control drills.

Well-control drills shall be conducted for each drilling crew in accordance with the requirements set forth in § 250.462 of this part or as approved by the District Manager.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 68 FR 8435, Feb. 20, 2003]

§ 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) 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.

(c) 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.

(d) 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.

[56 FR 32100, July 15, 1991. Redesignated at 63 FR 29479, May 29, 1998, as amended at 74 FR 46909, Sept. 14, 2009]

§ 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 § 250.455 through § 250.459 of this part, except that the installation of an operable degasser in the mud system as required in § 250.456(g) is not required for sulphur operations.

[56 FR 32100, July 15, 1991. Redesignated and amended at 63 FR 29479, 29487, May 29, 1998; 68 FR 8435, Feb. 20, 2003]

§ 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 Manager 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) Before drilling a well under an approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, you must file Form MMS–123, APD, with the District Manager for approval. The submission of your APD must be accompanied by payment of the service fee listed in § 250.125. Before starting operations, you must receive written approval from the District Manager unless you received oral approval under § 250.140.

(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 Manager 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 Manager.

(d) Public information copies of the APD shall be submitted in accordance with § 250.186 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; 71 FR 19646, Apr. 17, 2006; 71 FR 40913, July 19, 2006]

§ 250.1618 Application for permit to modify.

(a) You must submit requests for changes in plans, changes in major drilling equipment, proposals to deepen, sidetrack, complete, workover, or plug back a well, or engage in similar activities to the District Manager on Form MMS–124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in

§ 250.125. Before starting operations associated with the change, you must receive written approval from the District Manager unless you received oral approval under § 250.140.

(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; 71 FR 40913, July 19, 2006]

§ 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 Manager. 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 Manager 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 Manager 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, End of Operations Report, or Form MMS–124, Application for Permit to Modify, as appropriate.

(c) Upon request by the District Manager or Regional 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 Manager. 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 Manager in duplicate as soon as available but not later than 30 days after completion of such operations for each well.

(e) If the District Manager determines that circumstances warrant, the lessee shall submit any other reports and records of operations in the manner and form prescribed by the District Manager.

[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; 72 FR 25201, May 4, 2007]

§ 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 Manager. Approval for such operations shall be requested on Form MMS–124. Approvals by the District Manager 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 Manager.

(2) Within 30 days after completing the well-workover operation, except routine operations, Form MMS–124 shall be submitted to the District Manager 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 continuously 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 Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(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 Manager. 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 Manager.

§ 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 Manager 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 Manager. 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 (incorporated by reference as specified in § 250.198), 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 Manager certifying that the new installations conform to the approved designs of this subpart.

(c) *Hydrocarbon handling vessels associated with fuel gas system.* You must protect hydrocarbon handling vessels associated with the fuel gas system with a basic and ancillary surface safety system. This system must be designed, analyzed, installed, tested, and maintained in operating condition in accordance with API RP 14C, Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms (incorporated by reference as specified in § 250.198). If processing components are to be utilized, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the analysis technique and documentation specified therein to determine the effect 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 Manager 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 Manager. 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, incorporated by reference as specified in § 250.198) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c, incorporated by reference as specified in § 250.198).

(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 (incorporated by reference as specified in § 250.198), 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 Manager 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; 67 FR 51760, Aug. 9, 2002; 75 FR 22227, Apr. 28, 2010]

§ 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 must be designed, fabricated, and code stamped in accordance with the applicable provisions of sections I, IV, and VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (incorporated by reference as specified in 30 CFR 250.198). Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of API Pressure Vessel Inspections Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except Sections 5.8 and 9.5) (incorporated by reference as specified in § 250.198).

(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 (incorporated by reference as specified in 30 CFR 250.198). 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 Manager. 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.* You must equip engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4) (incorporated by reference as specified in § 250.198). Exhaust piping from diesel engines must be equipped with spark arresters.

(3) *Firefighting systems.* Firefighting systems must 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 (incorporated by reference as specified in § 250.198), and must be subject to the approval of the District Manager. Additional requirements must 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 Manager;

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Manager 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 (incorporated by reference as specified in § 205.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (incorporated by reference as specified in § 205.198).

(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 Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems must be an approved type, designed and installed according to API RP 14C, API RP 14G, and either API RP 14F or API RP 14FZ (the preceding four documents incorporated by reference as specified in § 250.198).

(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; 67 FR 51760, Aug. 9, 2002; 68 FR 43298, July 22, 2003; 70 FR 7403, Feb. 14, 2005; 72 FR 12096, Mar. 15, 2007; 73 FR 20172, Apr. 15, 2008; 75 FR 22227, Apr. 28, 2010]

§ 250.1630 Safety-system testing and records.

(a) *Inspection and testing.* You must inspect and successfully test safety system devices at the interval specified below or more frequently if operating conditions warrant. Testing must be in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198). For safety system devices other than those listed in API RP 14C, Appendix D, you must utilize the analysis technique and documentation specified therein 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 (excluding electronic pressure transmitters and level sensors) must be inspected and tested at least once each calendar month, but at no time may 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) The following electronic pressure transmitters and level sensors must be inspected and tested at least once every 3 months, but at no time may more than 120 days elapse between tests:

(i) All PSH or PSL, and

(ii) All LSH and LSL controls.

(4) All pumps for firewater systems shall be inspected and operated weekly.

(5) 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.

(6) Prior to the commencement of production, the lessee shall notify the District Manager when the lessee is ready to conduct a preproduction test and inspection of the safety system. The lessee shall also notify the District Manager 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 Manager. 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.

[56 FR 32100, July 15, 1991. Redesignated at 63 FR 29479, May 29, 1998, as amended at 67 FR 51761, Aug. 9, 2002]

§ 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.

Subpart Q—Decommissioning Activities

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

SOURCE: 67 FR 35406, May 17, 2002, unless otherwise noted.

GENERAL

§ 250.1700 What do the terms "decommissioning", "obstructions", and "facility" mean?

(a) *Decommissioning* means:

(1) Ending oil, gas, or sulphur operations; and

(2) Returning the lease or pipeline right-of-way to a condition that meets the requirements of regulations of MMS and other agencies that have jurisdiction over decommissioning activities.

(b) *Obstructions* means structures, equipment, or objects that were used in oil, gas, or sulphur operations or marine growth that, if left in place, would hinder other users of the OCS. Obstructions may include, but are not limited to, shell mounds, wellheads, casing stubs, mud line suspensions, well protection devices, subsea trees, jumper assemblies, umbilicals, manifolds, termination skids, production and pipeline risers, platforms, templates, pilings, pipelines, pipeline valves, and power cables.

(c) *Facility* means any installation other than a pipeline used for oil, gas, or sulphur activities that is permanently or temporarily attached to the seabed on the OCS. Facilities include production and pipeline risers, templates, pilings, and any other facility or equipment that constitutes an obstruction such as jumper assemblies, termination skids, umbilicals, anchors, and mooring lines.

[67 FR 35406, May 17, 2002; 67 FR 66047, Oct. 30, 2002]

§ 250.1701 Who must meet the decommissioning obligations in this subpart?

(a) Lessees and owners of operating rights are jointly and severally responsible for meeting decommissioning obligations for facilities on leases, including the obligations related to lease-term pipelines, as the obligations accrue and until each obligation is met.

(b) All holders of a right-of-way are jointly and severally liable for meeting decommissioning obligations for facilities on their right-of-way, including right-of-way pipelines, as the obligations accrue and until each obligation is met.

(c) In this subpart, the terms ''you'' or ''I'' refer to lessees and owners of operating rights, as to facilities installed under the authority of a lease, and to right-of-way holders as to facilities installed under the authority of a right-of-way.

§ 250.1702 When do I accrue decommissioning obligations?

You accrue decommissioning obligations when you do any of the following:

(a) Drill a well;

(b) Install a platform, pipeline, or other facility;

(c) Create an obstruction to other users of the OCS;

(d) Are or become a lessee or the owner of operating rights of a lease on which there is a well that has not been permanently plugged according to this subpart, a platform, a lease term pipeline, or other facility, or an obstruction;

(e) Are or become the holder of a pipeline right-of-way on which there is a pipeline, platform, or other facility, or an obstruction; or

(f) Re-enter a well that was previously plugged according to this subpart.

§ 250.1703 What are the general requirements for decommissioning?

When your facilities are no longer useful for operations, you must:

(a) Get approval from the appropriate District Manager before decommissioning wells and from the Regional Supervisor before decommissioning platforms and pipelines or other facilities;

(b) Permanently plug all wells;

(c) Remove all platforms and other facilities, except as provided in sections 1725(a) and 1730.

(d) Decommission all pipelines;

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations; and

(f) Conduct all decommissioning activities in a manner that is safe, does not unreasonably interfere with other uses of the OCS, and does not cause undue or serious harm or damage to the human, marine, or coastal environment.

[67 FR 35406, May 17, 2002, as amended at 74 FR 19807, Apr. 29, 2009]

§ 250.1704 When must I submit decommissioning applications and reports?

You must submit decommissioning applications and receive approval and submit subsequent reports according to the table in this section.

DECOMMISSIONING APPLICATIONS AND REPORTS TABLE

Decommissioning applications and reports	When to submit	Instructions
(a) Initial platform removal application [not required in the Gulf of Mexico OCS Region].	In the Pacific OCS Region or Alaska OCS Region, submit the application to the Regional Supervisor at least 2 years before production is projected to cease.	Include information required under § 250.1726.
(b) Final removal application for a platform or other facility.	Before removing a platform or other facility in the Gulf of Mexico OCS Region, or not more than 2 years after the submittal of an initial platform removal application to the Pacific OCS Region and the Alaska OCS Region.	Include information required under § 250.1727.
(c) Post-removal report for a platform or other facility.	Within 30 days after you remove a platform or other facility ...	Include information required under § 250.1729.

DECOMMISSIONING APPLICATIONS AND REPORTS TABLE—Continued

Decommissioning applications and reports	When to submit	Instructions
(d) Pipeline decommissioning application.	Before you decommission a pipeline	Include information required under § 250.1751(a) or § 250.1752(a), as applicable.
(e) Post-pipeline decommissioning report.	Within 30 days after you decommission a pipeline	Include information required under § 250.1753.
(f) Site clearance report for a platform or other facility.	Within 30 days after you complete site clearance verification activities.	Include information required under § 250.1743(b).
(g) Form MMS–124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125.	(1) Before you temporarily abandon or permanently plug a well or zone .	Include information required under §§ 250.1712 and 250.1721.
	(2) Within 30 days after you plug a well * * *	Include information required under § 250.1717.
	(3) Before you install a subsea protective device	Refer to § 250.1722(a).
	(4) Within 30 days after you complete a protective device trawl test.	Include information required under § 250.1722(d).
	(5) Before you remove any casing stub or mud line suspension equipment and any subsea protective device.	Refer to § 250.1723.
	(6) Within 30 days after you complete site clearance verification activities.	Include information required under § 250.1743(a).

[67 FR 35406, May 17, 2002; 67 FR 44265, July 1, 2002; 67 FR 66047, Oct. 30, 2002, as amended at 71 FR 40913, July 19, 2006]

PERMANENTLY PLUGGING WELLS

§ 250.1710 When must I permanently plug all wells on a lease?

You must permanently plug all wells on a lease within 1 year after the lease terminates.

§ 250.1711 When will MMS order me to permanently plug a well?

MMS will order you to permanently plug a well if that well:

(a) Poses a hazard to safety or the environment; or

(b) Is not useful for lease operations and is not capable of oil, gas, or sulphur production in paying quantities.

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

Before you permanently plug a well or zone, you must submit form MMS–124, Application for Permit to Modify, to the appropriate District Manager and receive approval. A request for approval must contain the following information:

(a) The reason you are plugging the well (or zone), for completions with production amounts specified by the Regional Supervisor, along with substantiating information demonstrating its lack of capacity for further profitable production of oil, gas, or sulfur;

(b) Recent well test data and pressure data, if available;

(c) Maximum possible surface pressure, and how it was determined;

(d) Type and weight of well-control fluid you will use;

(e) A description of the work; and

(f) A current and proposed well schematic and description that includes:

(1) Well depth;

(2) All perforated intervals that have not been plugged;

(3) Casing and tubing depths and details;

(4) Subsurface equipment;

(5) Estimated tops of cement (and the basis of the estimate) in each casing annulus;

(6) Plug locations;

(7) Plug types;

(8) Plug lengths;

(9) Properties of mud and cement to be used;

(10) Perforating and casing cutting plans;

(11) Plug testing plans;

(12) Casing removal (including information on explosives, if used);

(13) Proposed casing removal depth; and

(14) Your plans to protect archaeological and sensitive biological features, including anchor damage during plugging operations, a brief assessment of the environmental impacts of the plugging operations, and the procedures and mitigation measures you will take to minimize such impacts.

[67 FR 35406, May 17, 2002; 67 FR 66048, Oct. 30, 2002]

§ 250.1713 Must I notify MMS before I begin well plugging operations?

You must notify the appropriate District Manager at least 48 hours before beginning operations to permanently plug a well.

§ 250.1714 What must I accomplish with well plugs?

You must ensure that all well plugs:

(a) Provide downhole isolation of hydrocarbon and sulphur zones;

(b) Protect freshwater aquifers; and

(c) Prevent migration of formation fluids within the wellbore or to the seafloor.

§ 250.1715 How must I permanently plug a well?

(a) You must permanently plug wells according to the table in this section. The District Manager may require additional well plugs as necessary.

PERMANENT WELL PLUGGING REQUIREMENTS

If you have—	Then you must use—
(1) Zones in open hole	Cement plug(s) set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.
(2) Open hole below casing	(i) A cement plug, set by the displacement method, at least 100 feet above and below deepest casing shoe; (ii) A cement retainer with effective back-pressure control set 50 to 100 feet above the casing shoe, and a cement plug that extends at least 100 feet below the casing shoe and at least 50 feet above the retainer; or (iii) A bridge plug set 50 feet to 100 feet above the shoe with 50 feet of cement on top of the bridge plug, for expected or known lost circulation conditions.
(3) A perforated zone that is currently open and not previously squeezed or isolated.	(i) A method to squeeze cement to all perforations; (ii) A cement plug set by the displacement method, at least 100 feet above to 100 feet below the perforated interval, or down to a casing plug, whichever is less; or (iii) If the perforated zones are isolated from the hole below, you may use any of the plugs specified in paragraphs (a)(3)(iii)(A) through (E) of this section instead of those specified in paragraphs (a)(3)(i) and (a)(3)(ii) of this section. (A) A cement retainer with effective back-pressure control set 50 to 100 feet above the top of the perforated interval, and a cement plug that extends at least 100 feet below the bottom of the perforated interval with at least 50 feet of cement above the retainer; (B) A bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug; (C) A cement plug at least 200 feet in length, set by the displacement method, with the bottom of the plug no more than 100 feet above the perforated interval; (D) A through-tubing basket plug set no more than 100 feet above the perforated interval with at least 50 feet of cement on top of the basket plug; or (E) A tubing plug set no more than 100 feet above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 feet above the uppermost packer in the wellbore and at least 300 feet of cement in the casing annulus immediately above the packer.
(4) A casing stub where the stub end is within the casing.	(i) A cement plug set at least 100 feet above and below the stub end; (ii) A cement retainer or bridge plug set at least 50 to 100 feet above the stub end with at least 50 feet of cement on top of the retainer or bridge plug; or (iii) A cement plug at least 200 feet long with the bottom of the plug set no more than 100 feet above the stub end.
(5) A casing stub where the stub end is below the casing.	A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.
(6) An annular space that communicates with open hole and extends to the mud line.	A cement plug at least 200 feet long set in the annular space. For a well completed above the ocean surface, you must pressure test each casing annulus to verify isolation.
(7) A subsea well with unsealed annulus.	A cutter to sever the casing, and you must set a stub plug as specified in paragraphs (a)(4) and (a)(5) of this section.
(8) A well with casing	A cement surface plug at least 150 feet long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 feet below the mud line.
(9) Fluid left in the hole	A fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.
(10) Permafrost areas	(i) A fluid to be left in the hole that has a freezing point below the temperature of the permafrost, and a treatment to inhibit corrosion; and (ii) Cement plugs designed to set before freezing and have a low heat of hydration.

(b) You must test the first plug below the surface plug and all plugs in lost circulation areas that are in open hole. The plug must pass one of the following tests to verify plug integrity:

(1) A pipe weight of at least 15,000 pounds on the plug; or

(2) A pump pressure of at least 1,000 pounds per square inch. Ensure that the pressure does not drop more than 10 percent in 15 minutes. The District Manager may require you to tests other plug(s).

[67 FR 35406, May 17, 2002; 67 FR 44265, July 1, 2002; 67 FR 66048, Oct. 30, 2002]

§ 250.1716 To what depth must I remove wellheads and casings?

(a) Unless the District Manager approves an alternate depth under paragraph (b) of this section, you must remove all wellheads and casings to at least 15 feet below the mud line.

(b) The District Manager may approve an alternate removal depth if:

(1) The wellhead or casing would not become an obstruction to other users of the seafloor or area, and geotechnical and other information you provide demonstrate that erosional processes capable of exposing the obstructions are not expected; or

(2) You determine, and MMS concurs, that you must use divers, and the seafloor sediment stability poses safety concerns; or

(3) The water depth is greater than 800 meters (2,624 feet).

§ 250.1717 After I permanently plug a well, what information must I submit?

Within 30 days after you permanently plug a well, you must submit form MMS–124, Application for Permit to Modify (subsequent report), to the appropriate District Manager, and include the following information:

(a) Information included in § 250.1712 with a final well schematic;

(b) Description of the plugging work;

(c) Nature and quantities of material used in the plugs; and

(d) If you cut and pulled any casing string, the following information:

(1) A description of the methods used (including information on explosives, if used);

(2) Size and amount of casing removed; and

(3) Casing removal depth.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

TEMPORARY ABANDONED WELLS

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

You may temporarily abandon a well when it is necessary for proper development and production of a lease. To temporarily abandon a well, you must do all of the following:

(a) Submit form MMS–124, Application for Permit to Modify, and the applicable information required by § 250.1712 to the appropriate District Manager and receive approval;

(b) Adhere to the plugging and testing requirements for permanently plugged wells listed in the table in § 250.1715, except for § 250.1715 (a)(8). You do not need to sever the casings, remove the wellhead, or clear the site;

(c) Set a bridge plug or a cement plug at least 100-feet long 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;

(d) Set a retrievable or a permanent-type bridge plug or a cement plug at least 100 feet long in the inner-most casing. The top of the bridge plug or cement plug must be no more than 1,000 feet below the mud line. MMS may consider approving alternate requirements for subsea wells case-by-case;

(e) Identify and report subsea wellheads, casing stubs, or other obstructions that extend above the mud line according to U.S. Coast Guard (USCG) requirements; and

(f) Except in water depths greater than 300 feet, protect subsea wellheads, casing stubs, mud line suspensions, or other obstructions remaining above the seafloor by using one of the following methods, as approved by the District Manager or Regional Supervisor:

(1) A caisson designed according to 30 CFR 250, subpart I, and equipped with aids to navigation;

(2) A jacket designed according to 30 CFR 250, subpart I, and equipped with aids to navigation; or

(3) A subsea protective device that meets the requirements in § 250.1722.

(g) Within 30 days after you temporarily plug a well, you must submit form MMS–124, Application for Permit to Modify (subsequent report), and include the following information:

(1) Information included in § 250.1712 with a well schematic;

(2) Information required by § 250.1717(b), (c), and (d); and

(3) A description of any remaining subsea wellheads, casing stubs, mudline suspension equipment, or other obstructions that extend above the seafloor.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

§ 250.1722 If I install a subsea protective device, what requirements must I meet?

If you install a subsea protective device under § 250.1721(f)(3), you must install it in a manner that allows fishing gear to pass over the obstruction without damage to the obstruction, the protective device, or the fishing gear.

(a) Use form MMS–124, Application for Permit to Modify to request approval from the appropriate District Manager to install a subsea protective device.

(b) The protective device may not extend more than 10 feet above the seafloor (unless MMS approves otherwise).

(c) You must trawl over the protective device when you install it (adhere to the requirements at § 250.1741 (d) through (h)). If the trawl does not pass over the protective device or causes damage to it, you must notify the appropriate District Manager within 5 days and perform remedial action within 30 days of the trawl;

(d) Within 30 days after you complete the trawling test described in paragraph (c) of this section, submit a report to the appropriate District Manager using form MMS–124, Application for Permit to Modify, that includes the following:

(1) The date(s) the trawling test was performed and the vessel that was used;

(2) A plat at an appropriate scale showing the trawl lines;

(3) A description of the trawling operation and the net(s) that were used;

(4) An estimate by the trawling contractor of the seafloor penetration depth achieved by the trawl;

(5) A summary of the results of the trawling test including a discussion of any snags and interruptions, a description of any damage to the protective covering, the casing stub or mud line suspension equipment, or the trawl, and a discussion of any snag removals requiring diver assistance; and

(6) A letter signed by your authorized representative stating that he/she witnessed the trawling test.

(e) If a temporarily abandoned well is protected by a subsea device installed in a water depth less than 100 feet, mark the site with a buoy installed according to the USCG requirements.

(f) Provide annual reports to the Regional Supervisor describing your plans to either re-enter and complete the well or to permanently plug the well.

(g) Ensure that all subsea wellheads, casing stubs, mud line suspensions, or other obstructions in water depths less than 300 feet remain protected.

(1) To confirm that the subsea protective covering remains properly installed, either conduct a visual inspection or perform a trawl test at least annually.

(2) If the inspection reveals that a casing stub or mud line suspension is no longer properly protected, or if the trawl does not pass over the subsea protective covering without causing damage to the covering, the casing stub or mud line suspension equipment, or the trawl, notify the appropriate District Manager within 5 days, and perform the necessary remedial work within 30 days of discovery of the problem.

(3) In your annual report required by paragraph (f) of this section, include the inspection date, results, and method used and a description of any remedial work you will perform or have performed.

(h) You may request approval to waive the trawling test required by paragraph (c) of this section if you plan to use either:

(1) A buoy with automatic tracking capabilities installed and maintained according to USCG requirements at 33 CFR part 67 (or its successor); or

(2) A design and installation method that has been proven successful by trawl testing of previous protective devices of the same design and installed in areas with similar bottom conditions.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

§ 250.1723 What must I do when it is no longer necessary to maintain a well in temporary abandoned status?

If you or MMS determines that continued maintenance of a well in a temporary abandoned status is not necessary for the proper development or production of a lease, you must:

(a) Promptly and permanently plug the well according to § 250.1715;

(b) Remove any casing stub or mud line suspension equipment and any subsea protective covering. You must submit a request for approval to perform such work to the appropriate District Manager using form MMS–124, Application for Permit to Modify; and

(c) Clear the well site according to § 250.1740 through § 250.1742.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

Removing Platforms and Other Facilities

§ 250.1725 When do I have to remove platforms and other facilities?

(a) You must remove all platforms and other facilities within 1 year after the lease or pipeline right-of-way terminates, unless you receive approval to maintain the structure to conduct other activities. Platforms include production platforms, well jackets, single-well caissons, and pipeline accessory platforms. Other activities include those supporting OCS oil and gas production and transportation, as well as other energy-related or marine-related uses (including LNG) for which adequate financial assurance for decommissioning has been provided to a Federal agency which has given MMS a commitment that it has and will exercise authority to compel the performance of decommissioning within a time following cessation of the new use acceptable to MMS. The approval will specify:

(1) Whether you must continue to maintain any financial assurance for decommissioning; and

(2) Whether, and under what circumstances, you must perform any decommissioning not performed by the new facility owner/user.

(b) Before you may remove a platform or other facility, you must submit a final removal application to the Regional Supervisor for approval and include the information listed in § 250.1727.

(c) You must remove a platform or other facility according to the approved application.

(d) You must flush all production risers with seawater before you remove them.

(e) You must notify the Regional Supervisor at least 48 hours before you begin the removal operations.

[67 FR 35406, May 17, 2002, as amended at 74 FR 19807, Apr. 29, 2009]

§ 250.1726 When must I submit an initial platform removal application and what must it include?

An initial platform removal application is required only for leases and pipeline rights-of-way in the Pacific OCS Region or the Alaska OCS Region. It must include the following information:

(a) Platform or other facility removal procedures, including the types of vessels and equipment you will use;

(b) Facilities (including pipelines) you plan to remove or leave in place;

(c) Platform or other facility transportation and disposal plans;

(d) Plans to protect marine life and the environment during decommissioning operations, including a brief assessment of the environmental impacts of the operations, and procedures and mitigation measures that you will take to minimize the impacts; and

(e) A projected decommissioning schedule.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

§ 250.1727 What information must I include in my final application to remove a platform or other facility?

You must submit to the Regional Supervisor, a final application for approval to remove a platform or other facility. Your application must be accompanied by payment of the service fee listed in § 250.125. If you are proposing to use explosives, provide three copies of the application. If you are not proposing to use explosives, provide two copies of the application. Include the following information in the final removal application, as applicable:

(a) Identification of the applicant including:

(1) Lease operator/pipeline right-of-way holder;

(2) Address;

(3) Contact person and telephone number; and

(4) Shore base.

(b) Identification of the structure you are removing including:

(1) Platform Name/MMS Complex ID Number;

(2) Location (lease/right-of-way, area, block, and block coordinates);

(3) Date installed (year);

(4) Proposed date of removal (Month/Year); and

(5) Water depth.

(c) Description of the structure you are removing including:

(1) Configuration (attach a photograph or a diagram);

(2) Size;

(3) Number of legs/casings/pilings;

(4) Diameter and wall thickness of legs/casings/pilings;

(5) Whether piles are grouted inside or outside;

(6) Brief description of soil composition and condition;

(7) The sizes and weights of the jacket, topsides (by module), conductors, and pilings; and

(8) The maximum removal lift weight and estimated number of main lifts to remove the structure.

(d) A description, including anchor pattern, of the vessel(s) you will use to remove the structure.

(e) Identification of the purpose, including:

(1) Lease expiration/right-of-way relinquishment date; and

(2) Reason for removing the structure.

(f) A description of the removal method, including:

(1) A brief description of the method you will use;

(2) If you are using explosives, the following:

(i) Type of explosives;

(ii) Number and sizes of charges;

(iii) Whether you are using single shot or multiple shots;

(iv) If multiple shots, the sequence and timing of detonations;

(v) Whether you are using a bulk or shaped charge;

(vi) Depth of detonation below the mud line; and

(vii) Whether you are placing the explosives inside or outside of the pilings;

(3) If you will use divers or acoustic devices to conduct a pre-removal survey to detect the presence of turtles and marine mammals, a description of the proposed detection method; and

(4) A statement whether or not you will use transducers to measure the pressure and impulse of the detonations.

(g) Your plans for transportation and disposal (including as an artificial reef) or salvage of the removed platform.

(h) If available, the results of any recent biological surveys conducted in the vicinity of the structure and recent observations of turtles or marine mammals at the structure site.

(i) Your plans to protect archaeological and sensitive biological features during removal operations, including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures you will take to minimize such impacts.

(j) A statement whether or not you will use divers to survey the area after removal to determine any effects on marine life.

[67 FR 35406, May 17, 2002, as amended at 71 FR 40913, July 19, 2006]

§ 250.1728 To what depth must I remove a platform or other facility?

(a) Unless the Regional Supervisor approves an alternate depth under paragraph (b) of this section, you must remove all platforms and other facilities (including templates and pilings) to at least 15 feet below the mud line.

(b) The Regional Supervisor may approve an alternate removal depth if:

(1) The remaining structure would not become an obstruction to other users of the seafloor or area, and geotechnical and other information you provide demonstrate that erosional processes capable of exposing the obstructions are not expected; or

(2) You determine, and MMS concurs, that you must use divers and the seafloor sediment stability poses safety concerns; or

(3) The water depth is greater than 800 meters (2,624 feet).

§ 250.1729 After I remove a platform or other facility, what information must I submit?

Within 30 days after you remove a platform or other facility, you must submit a written report to the Regional Supervisor that includes the following:

(a) A summary of the removal operation including the date it was completed;

(b) A description of any mitigation measures you took; and

(c) A statement signed by your authorized representative that certifies that the types and amount of explosives you used in removing the platform or other facility were consistent with those set forth in the approved removal application.

§ 250.1730 When might MMS approve partial structure removal or toppling in place?

The Regional Supervisor may grant a departure from the requirement to remove a platform or other facility by approving partial structure removal or toppling in place for conversion to an artificial reef if you meet the following conditions:

(a) The structure becomes part of a State artificial reef program, and the responsible State agency acquires a permit from the U.S. Army Corps of Engineers and accepts title and liability for the structure; and

(b) You satisfy any U.S. Coast Guard (USCG) navigational requirements for the structure.

[67 FR 35406, May 17, 2002, as amended at 74 FR 19807, Apr. 29, 2009]

§ 250.1731 Who is responsible for decommissioning an OCS facility subject to an Alternate Use RUE?

(a) The holder of an Alternate Use RUE issued under part 285 of this subchapter is responsible for all decommissioning obligations that accrue following the issuance of the Alternate Use RUE and which pertain to the Alternate Use RUE. See 30 CFR part 285, subpart J, for additional information concerning the decommissioning responsibilities of an Alternate Use RUE grant holder.

(b) The lessee under the lease originally issued under 30 CFR part 256 will remain responsible for decommissioning obligations that accrued before issuance of the Alternate Use RUE, as well as for decommissioning obligations that accrue following issuance of the Alternate Use RUE to the extent associated with continued activities authorized under this part.

(c) If a lease issued under 30 CFR part 256 is cancelled or otherwise terminated under any provision of this subchapter, the lessee, upon our approval, may defer removal of any OCS facility within the lease area that is subject to an Alternate Use RUE. If we elect to grant such a deferral, the lessee remains responsible for removing the facility upon termination of the Alternate Use RUE and will be required to retain sufficient bonding or other financial assurances to ensure that the structure is removed or otherwise decommissioned in accordance with the provisions of this subpart.

[74 FR 19807, Apr. 29, 2009]

SITE CLEARANCE FOR WELLS, PLATFORMS, AND OTHER FACILITIES

§ 250.1740 How must I verify that the site of a permanently plugged well, removed platform, or other removed facility is clear of obstructions?

Within 60 days after you permanently plug a well or remove a platform or other facility, you must verify that the site is clear of obstructions by using one of the following methods:

(a) For a well site, you must either:

(1) Drag a trawl over the site;

(2) Scan across the location using sonar equipment;

(3) Inspect the site using a diver;

(4) Videotape the site using a camera on a remotely operated vehicle (ROV); or

(5) Use another method approved by the District Manager if the particular site conditions warrant.

(b) For a platform or other facility site in water depths less than 300 feet, you must drag a trawl over the site.

(c) For a platform or other facility site in water depths 300 feet or more, you must either:

(1) Drag a trawl over the site;

(2) Scan across the site using sonar equipment; or

(3) Use another method approved by the Regional Supervisor if the particular site conditions warrant.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

§ 250.1741 If I drag a trawl across a site, what requirements must I meet?

If you drag a trawl across the site in accordance with § 250.1740, you must meet all of the requirements of this section.

(a) You must drag the trawl in a grid-like pattern as shown in the following table:

For a—	You must drag the trawl across a—
(1) Well site	300-foot-radius circle centered on the well location.
(2) Subsea well site	600-foot-radius circle centered on the well location.
(3) Platform site	1,320-foot-radius circle centered on the location of the platform.
(4) Single-well caisson, well protector jacket, template, or manifold.	600-foot-radius circle centered on the structure location.

(b) You must trawl 100 percent of the limits described in paragraph (a) of this section in two directions.

(c) You must mark the area to be cleared as a hazard to navigation according to USCG requirements until you complete the site clearance procedures.

(d) You must use a trawling vessel equipped with a calibrated navigational positioning system capable of providing position accuracy of ±30 feet.

(e) You must use a trawling net that is representative of those used in the commercial fishing industry (one that has a net strength equal or greater than that provided by No. 18 twine).

(f) You must ensure that you trawl no closer than 300 feet from a shipwreck, and 500 feet from a sensitive biological feature.

(g) If you trawl near an active pipeline, you must meet the requirements in the following table:

For—	You must trawl—	And you must—
(1) Buried active pipelines		First contact the pipeline owner or operator to determine the condition of the pipeline before trawling over the buried pipeline.
(2) Unburied active pipelines that are 8 inches in diameter or larger.	no closer than 100 feet to the either side of the pipeline.	Trawl parallel to the pipeline Do not trawl across the pipeline.
(3) Unburied smaller diameter active pipelines in the trawl area that have obstructions (e.g., pipeline valves) present.	no closer than 100 feet to either side of the pipeline.	Trawl parallel to the pipeline. Do not trawl across the pipeline.
(4) Unburied active pipelines in the trawl area that are smaller than 8 inches in diameter and have no obstructions present.	parallel to the pipeline.	

(h) You must ensure that any trawling contractor you may use:

(1) Has no corporate or other financial ties to you; and

(2) Has a valid commercial trawling license for both the vessel and its captain.

[67 FR 35406, May 17, 2002; 67 FR 44266, July 1, 2002; 67 FR 66049, Oct. 30, 2002]

§ 250.1742 What other methods can I use to verify that a site is clear?

If you do not trawl a site, you can verify that the site is clear of obstructions by using any of the methods shown in the following table:

If you use—	You must—	And you must—
(a) Sonar	cover 100 percent of the appropriate grid area listed in § 250.1741(a).	Use a sonar signal with a frequency of at least 500 kHz.
(b) A diver	ensure that the diver visually inspects 100 percent of the appropriate grid area listed in § 250.1741(a).	Ensure that the diver uses a search pattern of concentric circles or parallel lines spaced no more than 10 feet apart.
(c) An ROV (remotely operated vehicle)	ensure that the ROV camera records videotape over 100 percent of the appropriate grid area listed in § 250.1741(a).	Ensure that the ROV uses a pattern of concentric circles or parallel lines spaced no more than 10 feet apart.

[67 FR 35406, May 17, 2002; 67 FR 44266, July 1, 2002]

§ 250.1743 How do I certify that a site is clear of obstructions?

(a) For a well site, you must submit to the appropriate District Manager within 30 days after you complete the verification activities a form MMS–124, Application for Permit to Modify, to include the following information:

(1) A signed certification that the well site area is cleared of all obstructions;

(2) The date the verification work was performed and the vessel used;

(3) The extent of the area surveyed;

(4) The survey method used;

(5) The results of the survey, including a list of any debris removed or a statement from the trawling contractor that no objects were recovered; and

(6) A post-trawling job plot or map showing the trawled area.

(b) For a platform or other facility site, you must submit the following information to the appropriate Regional Supervisor within 30 days after you complete the verification activities:

(1) A letter signed by an authorized company official certifying that the platform or other facility site area is cleared of all obstructions and that a company representative witnessed the verification activities;

(2) A letter signed by an authorized official of the company that performed the verification work for you certifying that they cleared the platform or other facility site area of all obstructions;

(3) The date the verification work was performed and the vessel used;

(4) The extent of the area surveyed;

(5) The survey method used;

(6) The results of the survey, including a list of any debris removed or a statement from the trawling contractor that no objects were recovered; and

(7) A post-trawling job plot or map showing the trawled area.

[67 FR 35406, May 17, 2002; 67 FR 66049, Oct. 30, 2002]

PIPELINE DECOMMISSIONING

§ 250.1750 When may I decommission a pipeline in place?

You may decommission a pipeline in place when the Regional Supervisor determines that the pipeline does not constitute a hazard (obstruction) to navigation and commercial fishing operations, unduly interfere with other uses of the OCS, or have adverse environmental effects.

§ 250.1751 How do I decommission a pipeline in place?

You must do the following to decommission a pipeline in place:

(a) Submit a pipeline decommissioning application in triplicate to the Regional Supervisor for approval. Your application must be accompanied by payment of the service fee listed in § 250.125. Your application must include the following information:

(1) Reason for the operation;

(2) Proposed decommissioning procedures;

(3) Length (feet) of segment to be decommissioned; and

(4) Length (feet) of segment remaining.

(b) Pig the pipeline, unless the Regional Supervisor determines that pigging is not practical;

(c) Flush the pipeline;

(d) Fill the pipeline with seawater;

(e) Cut and plug each end of the pipeline;

(f) Bury each end of the pipeline at least 3 feet below the seafloor or cover each end with protective concrete mats, if required by the Regional Supervisor; and

(g) Remove all pipeline valves and other fittings that could unduly interfere with other uses of the OCS.

[67 FR 35406, May 17, 2002, as amended at 71 FR 40913, July 19, 2006]

§ 250.1752 How do I remove a pipeline?

Before removing a pipeline, you must:

(a) Submit a pipeline removal application in triplicate to the Regional Supervisor for approval. Your application must be accompanied by payment of the service fee listed in § 250.125. Your application must include the following information:

(1) Proposed removal procedures;

(2) If the Regional Supervisor requires it, a description, including anchor pattern(s), of the vessel(s) you will use to remove the pipeline;

(3) Length (feet) to be removed;

(4) Length (feet) of the segment that will remain in place;

(5) Plans for transportation of the removed pipe for disposal or salvage;

(6) Plans to protect archaeological and sensitive biological features during removal operations, including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures that you will take to minimize such impacts; and

(7) Projected removal schedule and duration.

(b) Pig the pipeline, unless the Regional Supervisor determines that pigging is not practical; and

(c) Flush the pipeline.

[67 FR 35406, May 17, 2002, as amended at 71 FR 40913, July 19, 2006]

§ 250.1753 After I decommission a pipeline, what information must I submit?

Within 30 days after you decommission a pipeline, you must submit a written report to the Regional Supervisor that includes the following:

(a) A summary of the decommissioning operation including the date it was completed;

(b) A description of any mitigation measures you took; and

(c) A statement signed by your authorized representative that certifies that the pipeline was decommissioned according to the approved application.

§ 250.1754 When must I remove a pipeline decommissioned in place?

You must remove a pipeline decommissioned in place if the Regional Supervisor determines that the pipeline is an obstruction.

PART 251—GEOLOGICAL AND GEOPHYSICAL (G&G) EXPLORATIONS OF THE OUTER CONTINENTAL SHELF

Sec.