Electronic Code of Federal Regulations

e-CFR data is current as of April 29, 2020

Title 30: Mineral Resources

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

Contents

Authority: 30 U.S.C. 1751, 31 U.S.C. 9701, 33 U.S.C. 1321(j)(1)(C), 43 U.S.C. 1334.

Source: 76 FR 64462, Oct. 18, 2011, unless otherwise noted.

Editorial Note: Nomenclature changes to part 250 appear at 77 FR 50891, Aug. 22, 2012.

Back to Top

Subpart A—General

Back to Top

Authority and Definition of Terms

Back to Top

§250.101 Authority and applicability.

The Secretary of the Interior (Secretary) authorized the Bureau of Safety and Environmental Enforcement (BSEE) 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, BSEE 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.

Back to Top

§250.102 What does this part do?

(a) This part 250 contains the regulations of the BSEE 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 BSEE approval.

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

For information about . . .	Refer to . . .
(1) Applications for permit to drill,	30 CFR part 250, subpart D.
(2) Development and Production Plans (DPP),	30 CFR part 550, subpart B.
(3) Downhole commingling,	30 CFR part 250, subpart K.
(4) Exploration Plans (EP),	30 CFR part 550, subpart B.
(5) Flaring,	30 CFR part 250, subpart K.
(6) Gas measurement,	30 CFR part 250, subpart L.

(7) Off-lease geological and geophysical permits,	30 CFR part 551.
(8) Oil spill financial responsibility coverage,	30 CFR part 553.
(9) Oil and gas production safety systems,	30 CFR part 250, subpart H.
(10) Oil spill response plans,	30 CFR part 254.
(11) Oil and gas well-completion operations,	30 CFR part 250, subpart E.
(12) Oil and gas well-workover operations,	30 CFR part 250, subpart F.
(13) Decommissioning Activities,	30 CFR part 250, subpart Q.
(14) Platforms and structures,	30 CFR part 250, subpart I.
(15) Pipelines and Pipeline Rights-of-Way,	30 CFR part 250, subpart J and 30 CFR part 550, subpart J.
(16) Sulphur operations,	30 CFR part 250, subpart P.
(17) Training,	30 CFR part 250, subpart O.
(18) Unitization,	30 CFR part 250, subpart M.
(19) Safety and Environmental Management Systems (SEMS),	30 CFR part 250, subpart S.

[76 FR 64462, Oct. 18, 2011, as amended at 36148, June 6, 2016]

Back to Top

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

BSEE 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 BSEE.

Back to Top

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

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

Back to Top

§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 mean 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 Bureau of Ocean Energy Management (BOEM) 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.

Arctic OCS means the Beaufort Sea and Chukchi Sea Planning Areas (for more information on these areas, *see* the Proposed Final OCS Oil and Gas Leasing Program for 2012-2017 (June 2012) at *http://www.boem.gov/Oil-and-Gas-Energy-Program/Leasing/Five-Year-Program/2012-2017/Program-Area-Maps/index.aspx*).

Arctic OCS conditions means, for the purposes of this part, the conditions operators can reasonably expect during operations on the Arctic OCS. Such conditions, depending on the time of year, include, but are not limited to: Extreme cold, freezing spray, snow, extended periods of low light, strong winds, dense fog, sea ice, strong currents, and dangerous sea states. Remote location, relative lack of infrastructure, and the existence of subsistence hunting and fishing areas are also characteristic of the Arctic region.

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 BSEE 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 Supervisor 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.

Cap and flow system means an integrated suite of equipment and vessels, including a capping stack and associated flow lines, that, when installed or positioned, is used to control the flow of fluids escaping from the well by conveying the fluids to the surface to a vessel or facility equipped to process the flow of oil, gas, and water. A cap and flow system is a high pressure system that includes the capping stack and piping necessary to convey the flowing fluids through the choke manifold to the surface equipment.

Capping stack means a mechanical device, including one that is pre-positioned, that can be installed on top of a subsea or surface wellhead or blowout preventer to stop the uncontrolled flow of fluids into the environment.

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.

Containment dome means a non-pressurized container that can be used to collect fluids escaping from the well or equipment below the sea surface or from seeps by suspending the device over the discharge or seep location. The containment dome includes all of the equipment necessary to capture and convey fluids to the surface.

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 mean approvals granted by the appropriate BSEE or BOEM 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 mean 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 BSEE of the U.S. Department of the Interior, or an official authorized to act on the Director's behalf.

District Manager means the BSEE officer with authority and responsibility for operations or other designated program functions for a district within a BSEE Region. For activities on the Alaska OCS, any reference in this part to District Manager means the BSEE Regional Supervisor.

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 BOEM 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 mean 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 mean 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 30 CFR 550.303, 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 30 CFR 550.303, 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.

(5) As used in subpart S of this part, all types of structures permanently or temporarily attached to the seabed (e.g., mobile offshore drilling units (MODUs); floating production systems; floating production, storage and offloading facilities; tension-leg platforms; and spars) that are used for exploration, development, and production activities for oil, gas, or sulphur in the OCS. Facilities also include DOI-regulated pipelines.

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 mean 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 mean 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 BOEM-approved assignee of the lease, and the owner or the BOEM-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 mean 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 include 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 include, 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 mean 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 BSEE-approved or BOEM-approved designated agent of the lessee(s), or the holder of operating rights under a BOEM-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 mean 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 BSEE officer with responsibility and authority for a Region within BSEE.

Regional Supervisor means the BSEE officer with responsibility and authority for operations or other designated program functions within a BSEE Region.

Right-of-use means any authorization issued under 30 CFR Part 550 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, mean 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.

Source control and containment equipment (SCCE) means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels the collective purpose of which is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. “Surface devices” refers to equipment mounted or staged on a barge, vessel, or facility to separate, treat, store and/or dispose of fluids conveyed to the surface by the cap and flow system or the containment dome. “Subsea devices” includes, but is not limited to, remotely operated vehicles, anchors, buoyancy equipment, connectors, cameras, controls and other subsea equipment necessary to facilitate the deployment, operation, and retrieval of the SCCE. The SCCE does not include a blowout preventer.

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 mean 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 BOEM 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 mean 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.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20439, Apr. 5, 2013; 81 FR 46560, July 15, 2016]

Back to Top

Performance Standards

Back to Top

§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.

Back to Top

§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;

(2) Maintaining all equipment and work areas in a safe condition;

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

(4) Complying with all lease, plan, and permit terms and conditions.

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

(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.

(2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section.

(3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.

(d) BSEE may issue orders to ensure compliance with this part, including, but not limited to, orders to produce and submit records and to inspect, repair, and/or replace equipment. BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26014, Apr. 29, 2016; 81 FR 61915, Sept. 7, 2016]

Back to Top

§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 (as incorporated by reference in §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 (as incorporated by reference in §250.198).

(d) All cranes manufactured after March 17, 2003, and installed on a fixed platform, must meet the requirements of API Spec 2C.

(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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§250.114 How must I install, maintain, 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 (as incorporated by reference in §250.198), 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 (as incorporated by reference in §250.198).

(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 (as incorporated by reference 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 (as incorporated by reference 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36149, June 6, 2016]

Back to Top

§250.115 What are the procedures for, and effects of, incorporation of documents by reference in this part?

For the documents incorporated by reference in this part:

(a) Incorporation by reference of a document is limited to the edition of the document, or the specific edition and supplement or addendum, that is cited in §250.198. Future amendments or revisions of the incorporated document are not included. BSEE will publish any changes to the incorporation of the document in the Federal Register and amend §250.198 as appropriate.

(b) BSEE may make a rule amending the incorporation of a document effective without prior opportunity for public comment when BSEE determines:

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

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

(c) The effect of incorporation by reference of a document into the regulations in this part is that the incorporated document is a requirement. When a section in this part refers to an incorporated document, you are responsible for complying with the provisions of that entire document, except to the extent that the section that refers to the document provides otherwise. When a section in this part refers to a part of an incorporated document, you are responsible for complying with that part of the document as provided in that section.

(d) 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 prior written approval for alternative compliance from the authorized BSEE official.

[84 FR 21968, May 15, 2019]

Back to Top

§§250.116-250.117 [Reserved]

Back to Top

Gas Storage or Injection

Back to Top

§250.118 Will BSEE 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 BSEE 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.

Back to Top

§250.119 [Reserved]

Back to Top

§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 30 CFR 550.119, 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.

Back to Top

§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 a BSEE-approved formula to determine the amounts of injected or stored gas and gas original to the reservoir.

Back to Top

§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.

Back to Top

§250.123 [Reserved]

Back to Top

§250.124 Will BSEE 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.

Back to Top

Fees

Back to Top

§250.125 Service fees.

(a) The table in this paragraph (a) shows the fees that you must pay to BSEE 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—processing of the following:	Fee amount	30 CFR citation
(1) Suspension of Operations/Suspension of Production (SOO/SOP) Request	$2,123	§250.171(e).
(2) Deepwater Operations Plan (DWOP)	$3,599	§250.292(q).
(3) Application for Permit to Drill (APD); Form BSEE-0123	$2,113 for initial applications only; no fee for revisions	§250.410(d); §250.513(b); §250.1617(a).
(4) Application for Permit to Modify (APM); Form BSEE-0124	$125	§250.465(b); §250.513(b); §250.613(b); §250.1618(a); §250.1704(g).
(5) New Facility Production	$5,426	§250.842.

Safety System Application for facility with more than 125 components	$14,280 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $7,426 for an inspection of a facility while in a shipyard 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 (as incorporated by reference in §250.198)	
(6) New Facility Production Safety System Application for facility with 25-125 components	$1,314 $8,967 additional fee will be charged if BSEE conducts a pre-production inspection of a facility offshore, and $5,141 for an inspection of a facility while in a shipyard	§250.842.
(7) New Facility Production Safety System Application for facility with fewer than 25 components	$652	§250.842.
(8) Production Safety System Application—Modification with more than 125 components reviewed	$605	§250.842.
(9) Production Safety System Application—Modification with 25-125 components reviewed	$217	§250.842.
(10) Production Safety System Application—Modification with fewer than 25 components reviewed	$92	§250.842.
(11) Platform Application—Installation—Under the Platform Verification Program	$22,734	§250.905(l).
(12) Platform Application—Installation—Fixed Structure Under the Platform Approval Program	$3,256	§250.905(l).
(13) Platform Application—Installation—Caisson/Well Protector	$1,657	§250.905(l)
(14) Platform Application—Modification/Repair	$3,884	§250.905(l).
(15) New Pipeline Application (Lease Term)	$3,541	§250.1000(b).
(16) Pipeline Application—Modification (Lease Term)	$2,056	§250.1000(b).
(17) Pipeline Application—Modification (ROW)	$4,169	§250.1000(b).
(18) Pipeline Repair Notification	$388	§250.1008(e).
(19) Pipeline Right-of-Way (ROW) Grant Application	$2,771	§250.1015(a).
(20) Pipeline Conversion of Lease Term to ROW	$236	§250.1015(a).
(21) Pipeline ROW Assignment	$201	§250.1018(b).
(22) 500 Feet From Lease/Unit Line Production Request	$3,892	§250.1156(a).
(23) Gas Cap Production Request	$4,953	§250.1157.
(24) Downhole Commingling Request	$5,779	§250.1158(a).
(25) Complex Surface Commingling and Measurement Application	$4,056	§250.1202(a); §250.1203(b); §250.1204(a).
(26) Simple Surface Commingling and Measurement Application	$1,371	§250.1202(a); §250.1203(b); §250.1204(a).
(27) Voluntary Unitization Proposal or Unit Expansion	$12,619	§250.1303(d).
(28) Unitization Revision	$896	§250.1303(d).
(29) Application to Remove a Platform or Other Facility	$4,684	§250.1727.

(30) Application to Decommission a Pipeline (Lease Term)	$1,142	§250.1751(a) or §250.1752(a).
(31) Application to Decommission a Pipeline (ROW)	$2,170	§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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50891, Aug. 22, 2012; 78 FR 60213, Oct. 1, 2013; 81 FR 26014, Apr. 29, 2016; 81 FR 61916, Sept. 7, 2016]

Back to Top

§250.126 Electronic payment instructions.

(a) You must file all payments electronically through the Fees for Services page on the BSEE Web site at *http://www.bsee.gov.* This includes, but is not limited to, all OCS applications, permits, or any filing fees. You must include a copy of the *Pay.gov* confirmation receipt page with your application, permit, or filing fee.

(b) If you submitted an application or permit through eWell, you must use the interactive payment feature in that system, which directs you through *Pay.gov* to make a payment. It is recommended that you keep a copy of your payment confirmation receipt in the event that any questions arise regarding your transaction.

[81 FR 36149, June 6, 2016]

Back to Top

Inspections of Operations

Back to Top

§250.130 Why does BSEE conduct inspections?

BSEE 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 BOEM-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.

Back to Top

§250.131 Will BSEE notify me before conducting an inspection?

BSEE conducts both scheduled and unscheduled inspections.

Back to Top

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

(a) When BSEE 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.

Back to Top

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

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

Back to Top

Disqualification

Back to Top

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

BSEE will determine if your operating performance is unacceptable. BSEE will refer a determination of unacceptable performance to BOEM, who 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 BSEE officials before making a determination that your operating performance is unacceptable.

Back to Top

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

In determining if your operating performance is unacceptable, BSEE 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.

Back to Top

Special Types of Approvals

Back to Top

§250.140 When will I receive an oral approval?

When you apply for BSEE 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).

Back to Top

§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 BSEE 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 Regional Supervisor. Your presentation must describe the site-specific application(s), performance characteristics, and safety features of the proposed procedure or equipment.

Back to Top

§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.

Back to Top

§§250.143-250.144 [Reserved]

Back to Top

§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.

Back to Top

§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 and 30 CFR parts 550 through 582 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 and 30 CFR parts 550 through 582, 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 and 30 CFR parts 550 through 582 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.

Back to Top

Naming and Identifying Facilities and Wells (Does Not Include MODUs)

Back to Top

§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.

Back to Top

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

The operator assigns a name to the facility.

Back to Top

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

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

Back to Top

§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.

Back to Top

§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.

Back to Top

§§250.160-250.167 [Reserved]

Back to Top

Suspensions

Back to Top

§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).

Back to Top

§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.

Back to Top

§250.170 How long does a suspension last?

(a) BSEE 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. BSEE 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) BSEE 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.

Back to Top

§250.171 How do I request a suspension?

You must submit your request for a suspension to the Regional Supervisor, and BSEE must receive the request before the end of the lease term (*i.e.,* end of primary term, end of the 1-year 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 §250.1603 (SOP only), 30 CFR 550.115, or 30 CFR 550.116;

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

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

[76 FR 64462, Oct. 18, 2011, as amended at 82 FR 26744, June 9, 2017]

Back to Top

§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. BSEE 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.

Back to Top

§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.

Back to Top

§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).

Back to Top

§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) Five years; or

(ii) Eight 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.

Back to Top

§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 30 CFR 1218.154.

Back to Top

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

If BSEE 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) BSEE 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 550, subpart B.

Back to Top

Primary Lease Requirements, Lease Term Extensions, and Lease Cancellations

Back to Top

§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 year of the primary term, and whenever production resumes during the last year 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 556). 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 year 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 year 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 year after you stop operations.

(e) You may ask the Regional Supervisor to allow you more than a year 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 1-year period after having ceased, or whenever drilling or well-reworking operations begin before the end of the 1-year 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 1-year period.

[76 FR 64462, Oct. 18, 2011, as amended at 82 FR 26744, June 9, 2017]

Back to Top

§§250.181-250.185 [Reserved]

Back to Top

Information and Reporting Requirements

Back to Top

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

(a) You must submit information and reports as BSEE 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 BSEE's forms. You must arrange the data on your form identical to the BSEE form. If you generate your own form and it omits terms and conditions contained on the official BSEE 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 BSEE 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.

Back to Top

§250.187 What are BSEE's 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 BOEM or BSEE, 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.

Back to Top

§250.188 What incidents must I report to BSEE 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.

(c) On the Arctic OCS, in addition to the requirements of paragraphs (a) and (b) of this section, you must provide to the BSEE inspector on location, if one is present, or to the Regional Supervisor, both of the following:

(1) An immediate oral report if any of the following occur:

(i) Any sea ice movement or condition that has the potential to affect your operation or trigger ice management activities;

(ii) The start and termination of ice management activities; or

(iii) Any “kicks” or operational issues that are unexpected and could result in the loss of well control.

(2) Within 24 hours after completing ice management activities, a written report of such activities that conforms to the content requirements in §250.190.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 46560, July 15, 2016]

Back to Top

§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.

Back to Top

§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.

Back to Top

§250.191 How does BSEE conduct incident investigations?

Any investigation that BSEE 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 BSEE. 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.

Back to Top

§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 BSEE GOM OCS Region, use Form BSEE-0132) 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 BSEE when you resume production; and

(4) Submit the statistics either by BSEE district, or the total figures for your operations in a BSEE 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 BSEE-0143, Facility/Equipment Damage Report, to make this and all subsequent reports. In lieu of submitting Form BSEE-0143 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.

Back to Top

§250.193 Reports and investigations of possible violations.

(a) Any person may report to BSEE any hazardous or unsafe working condition on any facility engaged in OCS activities, and any possible violation or failure to comply with:

(1) Any provision of the Act,

(2) Any provision of a lease, approved plan, or permit issued under the Act,

(3) Any provision of any regulation or order issued under the Act, or

(4) Any other Federal law relating to safety of offshore oil and gas operations.

(b) To make a report under this section, a person is not required to know whether any legal requirement listed in paragraph (a) of this section has been violated.

(c) When BSEE receives a report of a possible violation, or when a BSEE employee detects a possible violation, BSEE will investigate according to BSEE procedures and notify any other Federal agency(ies) for further investigation, as appropriate.

(d) BSEE investigations of possible violations may include:

(1) Conducting interviews of personnel;

(2) Requiring the prompt production of documents, data, and other evidence;

(3) Requiring the preservation of all relevant evidence and access for BSEE investigators to such evidence; and

(4) Taking other actions and imposing other requirements as necessary to investigate possible violations and assure an orderly investigation.

(e)(1) Reports should contain sufficient credible information to establish a reasonable basis for BSEE to investigate whether a violation or other hazardous or unsafe working condition exists.

(2) To report hazardous or unsafe working conditions or a possible violation:

(i) Contact BSEE by:

(A) Phone at 1-877-440-0173 (BSEE Toll-free Safety Hotline),

(B) Internet at *www.bsee.gov,* or

(C) Mail to: U.S. DOI/BSEE, 1849 C Street NW., Mail Stop 5438, Washington, DC 20240 Attention: IRU Hotline Operations.

(ii) Include the following items in the report:

(A) Name, address, and telephone number should be provided if you do not want to remain anonymous;

(B) The specific concern, provision or Federal law, if known, referenced in (a) that a person violated or with which a person failed to comply; and

(C) Any other facts, data, and applicable information.

(f) When a possible violation is reported, BSEE will protect a person's identity to the extent authorized by law.

[78 FR 20439, Apr. 5, 2013, as amended at 81 FR 36149, June 6, 2016]

Back to Top

§250.194 How must I protect archaeological resources?

(a)-(b) [Reserved]

(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 BSEE Regional Director. If investigations determine that the resource is significant, the Regional Director will tell you how to protect it.

Back to Top

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

You must notify the appropriate BSEE 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.

Back to Top

§250.196 Reimbursements for reproduction and processing costs.

(a) BSEE 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 BSEE for the Regional Director to inspect or select and retain;

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

Back to Top

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

BSEE will protect data and information that you submit under this part, and 30 CFR part 203, 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 BSEE 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) BSEE-0123, 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) BSEE-0123S, 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) BSEE-0124, 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) BSEE-0125, 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) BSEE-0126, Well Potential Test Report,	Item 101,	2 years after you submit it.
(6) [Reserved]		
(7) BSEE-0133 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) BSEE-0133S 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) [Reserved]		
(10) [Reserved]		

(b) BSEE will release lease and permit data and information that you submit and BSEE retains, but that are not normally submitted on BSEE forms, according to the following table:

If . . .	**BSEE 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,	BSEE 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 BSEE receives the data or information, if the Regional Supervisor deems it necessary,	BSEE 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 30 CFR 550, 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 30 CFR 552.7 do not apply. The release time applies to the geophysical data and information only if acquired postlease for a lessee's exclusive use.
(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 30 CFR 552.7 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 30 CFR 552.7 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 30 CFR part 551 are submitted by a lessee under 30 CFR part 203, 30 CFR part 250, or 30 CFR part 550,	G&G data, analyzed geological information, processed and interpreted G&G information,	Geological data and information: 10 years after BOEM issues the permit; Geophysical data: 50 years after BOEM issues the permit; Geophysical information: 25 years after BOEM issues the permit,	None.

(c) BSEE may allow limited inspection, but only by persons with a direct interest in related BSEE 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 30 CFR part 203 that BSEE 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) [Reserved]; or

(7) Determine eligibility for royalty relief.

Back to Top

References

Back to Top

§250.198 Documents incorporated by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All incorporated material is available for inspection at the Houston BSEE office at 1919 Smith Street Suite 14042, Houston, Texas 77002 and is available from the sources indicated in this section. It is also available for inspection at the National Archives and Records Administration (NARA). To make an appointment to inspect incorporated material at the Houston BSEE office, call 1-844-259-4779. For information on the availability of this material at NARA, call 202-741-6030 or go to *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

(a) American Concrete Institute (ACI), ACI Standards, 38800 Country Club Drive, Farmington Hills, MI 48331-3439: *http://www.concrete.org;* phone: 248-848-3700:

(1) ACI Standard 318-95, Building Code Requirements for Reinforced Concrete, 1995; incorporated by reference at §250.901.

(2) ACI 318R-95, Commentary on Building Code Requirements for Reinforced Concrete, 1995; incorporated by reference at §250.901.

(3) ACI 357R-84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984; reapproved

1997, incorporated by reference at §250.901.

(b) American Gas Association (AGA Reports), 400 North Capitol Street NW, Suite 450, Washington, DC 20001, *http://www.aga.org;* phone: 202-824-7000;

(1) AGA Report No. 7—Measurement of Natural Gas by Turbine Meters; Revised February 2006; incorporated by reference at §250.1203(b);

(2) AGA Report No. 9—Measurement of Gas by Multipath Ultrasonic Meters; Second Edition, April 2007; incorporated by reference at §250.1203(b);

(3) AGA Report No. 10—Speed of Sound in Natural Gas and Other Related Hydrocarbon Gases; Copyright 2003; incorporated by reference at §250.1203(b).

(c) 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.

(2) [Reserved]

(d) American National Standards Institute (ANSI), *http.www./webstore.ansi.org/;* phone: 212-642-4900:

(1) ANSI/ASME B 16.5-2003, Pipe Flanges and Flanged Fittings, incorporated by reference at §250.1002;

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

(3) ANSI Z88.2-1992, American National Standard for Respiratory Protection, incorporated by reference at §250.490.

(e) 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, Tenth Edition, May 2014; Addendum 1, May 2017; incorporated by reference at §§250.851(a) and 250.1629(b);

(2) API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Fourth Edition, February 2016; Addendum 1, May 2017; incorporated by reference at §250.841(b).

(3) API Bulletin 2INT-DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at §250.901;

(4) API Bulletin 2INT-EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, May 2007; incorporated by reference at §250.901;

(5) API Bulletin 2INT-MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, May 2007; incorporated by reference at §250.901;

(6) API Bulletin 92L, Drilling Ahead Safely with Lost Circulation in the Gulf of Mexico, First Edition, August 2015; incorporated by reference at §250.427(b);

(7) API MPMS Chapter 1—Vocabulary, Second Edition, July 1994; incorporated by reference at §250.1201;

(8) 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; incorporated by reference at §250.1202;

(9) 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; incorporated by reference at §250.1202;

(10) API MPMS Chapter 3—Tank Gauging, Section 1A—Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, Second Edition, August 2005; incorporated by reference at §250.1202;

(11) 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; incorporated by reference at §250.1202;

(12) API MPMS Chapter 4—Proving Systems, Section 1—Introduction, Third Edition, February 2005; incorporated by reference at §250.1202;

(13) API MPMS Chapter 4—Proving Systems, Section 2—Displacement Provers, Third Edition, September 2003; incorporated by reference at §250.1202;

(14) API MPMS Chapter 4—Proving Systems, Section 4—Tank Provers, Second Edition, May 1998, reaffirmed November 2005; incorporated by reference at §250.1202;

(15) API MPMS Chapter 4—Proving Systems, Section 5—Master-Meter Provers, Second Edition, May 2000, reaffirmed, August 2005; incorporated by reference at §250.1202;

(16) API MPMS Chapter 4—Proving Systems, Section 6—Pulse Interpolation, Second Edition, May 1999; reaffirmed 2003; incorporated by reference at §250.1202;

(17) API MPMS Chapter 4—Proving Systems, Section 7—Field Standard Test Measures, Second Edition, December 1998; reaffirmed 2003; incorporated by reference at §250.1202;

(18) API MPMS Chapter 4—Proving Systems, Section 8—Operation of Proving Systems; First Edition, reaffirmed March 2007; incorporated by reference at §250.1202(a), (f), and (g);

(19) API MPMS Chapter 5—Metering, Section 1—General Considerations for Measurement by Meters, Fourth Edition, September 2005; incorporated by reference at §250.1202;

(20) API MPMS Chapter 5—Metering, Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters, Third Edition, September 2005; incorporated by reference at §250.1202;

(21) API MPMS Chapter 5—Metering, Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters, Fifth Edition, September 2005; incorporated by reference at §250.1202;

(22) API MPMS Chapter 5—Metering, Section 4—Accessory Equipment for Liquid Meters, Fourth Edition, September 2005; incorporated by reference at §250.1202;

(23) API MPMS Chapter 5—Metering, Section 5—Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems, Second Edition, August 2005; incorporated by reference at §250.1202;

(24) API MPMS Chapter 5—Metering, Section 6—Measurement of Liquid Hydrocarbons by Coriolis Meters; First Edition, reaffirmed, March 2008; incorporated by reference at §250.1202(a);

(25) API MPMS Chapter 5—Metering, Section 8—Measurement of Liquid Hydrocarbons by Ultrasonic Flow Meters Using Transit Time Technology; First Edition, February 2005; incorporated by reference at §250.1202(a);

(26) API MPMS Chapter 6—Metering Assemblies, Section 1—Lease Automatic Custody Transfer (LACT) Systems, Second Edition, May 1991; reaffirmed, April 2007; incorporated by reference at §250.1202;

(27) API MPMS Chapter 6—Metering Assemblies, Section 6—Pipeline Metering Systems, Second Edition, May 1991; reaffirmed, February 2007; incorporated by reference at §250.1202;

(28) API MPMS Chapter 6—Metering Assemblies, Section 7—Metering Viscous Hydrocarbons, Second Edition, May 1991; reaffirmed, April 2007; incorporated by reference at §250.1202;

(29) API MPMS Chapter 7—Temperature Determination, First Edition, June 2001; reaffirmed, March 2007; incorporated by reference at §250.1202;

(30) API MPMS Chapter 8—Sampling, Section 1—Standard Practice for Manual Sampling of Petroleum and Petroleum Products, Third Edition, October 1995; reaffirmed, March 2006; incorporated by reference at §250.1202;

(31) 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; incorporated by reference at §250.1202;

(32) 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; incorporated by reference at §250.1202(a) and (l);

(33) 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; incorporated by reference at §250.1202;

(34) 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; incorporated by reference at §250.1202;

(35) API MPMS Chapter 10—Sediment and Water, Section 2—Standard Test Method for Water in Crude Oil by Distillation, Second Edition, November 2007; incorporated by reference at §250.1202;

(36) 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; incorporated by reference at §250.1202;

(37) 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; incorporated by reference at §250.1202;

(38) 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; incorporated by reference at §250.1202;

(39) 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; incorporated by reference at §250.1202;

(40) 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; incorporated by reference at §250.1202;

(41) API MPMS Chapter 11—Physical Properties Data, Section 1—Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils; May 2004 (incorporating Addendum 1, September 2007); incorporated by reference at §250.1202(a), (g), and (l);

(42) 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; incorporated by reference at §250.1202;

(43) 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; incorporated by reference at §250.1202;

(44) 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; incorporated by reference at §250.1202;

(45) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 3—Proving Reports; First Edition, reaffirmed 2009; incorporated by reference at §250.1202(a) and (g);

(46) API MPMS Chapter 12—Calculation of Petroleum Quantities, Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors, Part 4—Calculation of Base Prover Volumes by the Waterdraw Method, First Edition, December 1997; reaffirmed, 2009; incorporated by reference at §250.1202(a), (f), and (g);

(47) 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; incorporated by reference at §250.1203;

(48) 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; incorporated by reference at §250.1203;

(49) 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; incorporated by reference at §250.1203;

(50) 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; incorporated by reference at §250.1203;

(51) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 6—Continuous Density Measurement, Second Edition, April 1991; reaffirmed, February 2006; incorporated by reference at §250.1203;

(52) API MPMS Chapter 14—Natural Gas Fluids Measurement, Section 8—Liquefied Petroleum Gas Measurement, Second Edition, July 1997; reaffirmed, March 2006; incorporated by reference at §250.1203;

(53) API MPMS Chapter 20—Section 1—Allocation Measurement, First Edition, September 1993; reaffirmed October 2006; incorporated by reference at §250.1202;

(54) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 1—Electronic Gas Measurement, First Edition, August 1993; reaffirmed, July 2005; incorporated by reference at §250.1203;

(55) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Section 2—Electronic Liquid Volume Measurement Using Positive Displacement and Turbine Meters; First Edition, June 1998; incorporated by reference at §250.1202(a);

(56) API MPMS Chapter 21—Flow Measurement Using Electronic Metering Systems, Addendum to Section 2—Flow Measurement Using Electronic Metering Systems, Inferred Mass; First Edition, reaffirmed February 2006; incorporated by reference at §250.1202(a);

(57) 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; incorporated by reference at §§250.901, 250.908, 250.919, and 250.920;

(58) API RP 2D, Operation and Maintenance of Offshore Cranes, Sixth Edition, May 2007; incorporated by reference at §250.108;

(59) API RP 2FPS, RP for Planning, Designing, and Constructing Floating Production Systems; First Edition, March 2001; incorporated by reference at §250.901;

(60) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Structures; Third Edition, April 2008; incorporated by reference at §250.901(a) and (d);

(61) ANSI/API RP 2N, Third Edition, "Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions", Third Edition, April 2015; incorporated by reference at §250.470(g);

(62) 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; incorporated by reference at §§250.733, 250.800(c), 250.901(a), (d), and 250.1002(b);

(63) API RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, reaffirmed June 2015; incorporated by reference at §§250.800(c) and 250.901(a) and (d);

(64) 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; incorporated by reference at §§250.800(c) and 250.901(a) and (d);

(65) API RP 2T, Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997; incorporated by reference at §250.901(a) and (d);

(66) ANSI/API RP 14B, Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems, Sixth Edition, September 2015; incorporated by reference at §§250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c);

(67) 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; incorporated by reference at §§250.125(a), 250.292(j), 250.841(a), 250.842(a), 250.850, 250.852(a), 250.855, 250.856(a), 250.858(a), 250.862(e), 250.865(a), 250.867(a), 250.869(a) through (c), 250.872(a), 250.873(a), 250.874(a), 250.880(b) and (c), 250.1002(d), 250.1004(b), 250.1628(c) and (d), 250.1629(b), and 250.1630(a);

(68) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; reaffirmed, January 2013; incorporated by reference at §§250.841(b), 250.842(a), and 250.1628(b) and (d);

(69) API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, reaffirmed: April 2013; incorporated by reference at §§250.114(c), 250.842(c), 250.862(e), and 250.1629(b);

(70) API RP 14FZ, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, Second Edition, May 2013; incorporated by reference at §§250.114(c), 250.842(c), 250.862(e), and 250.1629(b);

(71) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; Reaffirmed, January 2013; incorporated by reference at §§250.859(a), 250.862(e), 250.880(c), and 250.1629(b);

(72) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; reaffirmed: January 2013; incorporated by reference at §§250.800(b) and (c), 250.842(c), and 250.901(a) and (d);

(73) API RP 17H, Remotely Operated Tools and Interfaces on Subsea Production Systems, Second Edition, June 2013; Errata, January 2014; incorporated by reference at §250.734(a);

(74) API RP 65, Recommended Practice for Cementing Shallow Water Flow Zones in Deepwater Wells, First Edition, September 2002; incorporated by reference at §250.415;

(75) API RP 75, Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities, Third Edition, May 2004, reaffirmed May 2008; incorporated by reference at §§250.1900, 250.1902, 250.1903, 250.1909, 250.1920;

(76) API RP 86, API Recommended Practice for Measurement of Multiphase Flow; First Edition, September 2005; incorporated by reference at §§250.1202(a) and 250.1203(b);

(77) API RP 90, Annular Casing Pressure Management for Offshore Wells, First Edition, August 2006; incorporated by reference at §250.519;

(78) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Third Edition, December 2012; Errata January 2014, incorporated by reference at §§250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

(79) 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, August 2013; incorporated by reference at §§250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);

(80) API RP 2556, Recommended Practice for Correcting Gauge Tables for Incrustation, Second Edition, August 1993; reaffirmed November 2003; incorporated by reference at §250.1202;

(81) API Spec. 2C, Specification for Offshore Pedestal Mounted Cranes, Sixth Edition, March 2004, Effective Date: September 2004; incorporated by reference at §250.108;

(82) ANSI/API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition, October 2010; Addendum 1, November 2011; Errata 2, November 2011; Addendum 2, November 2012; Addendum 3, March 2013; Errata 3, June 2013; Errata 4, August 2013; Errata 5, November 2013; Errata 6, March 2014; Errata 7, December 2014; Errata 8, February 2016; Addendum 4, June 2016; Errata 9, June 2016; Errata 10, August 2016; incorporated by reference at §§250.730, 250.802(a), 250.803(a), 250.833, 250.873(b), 250.874(g), and 250.1002(b);

(83) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, Second Edition, February 2013; incorporated by reference at §§250.802(a), 250.833, 250.873(b), and 250.874(g);

(84) API STD 6AV2, Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore; First Edition, March 2014; Errata 1, August 2014; incorporated by reference at §§250.820, 250.834, 250.836, and 250.880(c)

(85) 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; incorporated by reference at §250.1002(b);

(86) ANSI/API Spec. 11D1, Packers and Bridge Plugs, Second Edition, July 2009; incorporated by reference at §§250.518, 250.619, and 250.1703;

(87) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, reaffirmed, June 2012; incorporated by reference at §§250.802 and 250.803(a);

(88) ANSI/API Spec. 16A, Specification for Drill-through Equipment, Third Edition, June 2004, reaffirmed August 2010; incorporated by reference at §250.730;

(89) ANSI/API Spec. 16C, Specification for Choke and Kill Systems, First Edition, January 1993, reaffirmed July 2010; incorporated by reference at §250.730;

(90) API Spec. 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, reaffirmed August 2013; incorporated by reference at §250.730;

(91) ANSI/API Spec. 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition, May 2011; incorporated by reference at §250.730;

(92) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008, incorporated by reference at §§250.852(e), 250.1002(b), and 250.1007(a).

(93) ANSI/API Spec. Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, June 2013; Errata, February 2014; Errata 2, March 2014; Addendum 1, June 2016; incorporated by reference at §§250.730 and 250.801(b) and (c);

(94) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, Addendum 1, July 2016, incorporated by reference at §§250.730, 250.734, 250.735, 250.736, 250.737, and 250.739;

(95) API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction; Second Edition, December 2010; incorporated by reference at §§250.415(f) and 250.420(a);

(96) API Standard 2552, USA Standard Method for Measurement and Calibration of Spheres and Spheroids, First Edition, 1966; reaffirmed, October 2007; incorporated by reference at §250.1202;

(97) API Standard 2555, Method for Liquid Calibration of Tanks, First Edition, September 1966; reaffirmed March 2002; incorporated by reference at §250.1202;

(f) American Society of Mechanical Engineers (ASME), 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007-2900; *http://www.asme.org;* phone: 1-800-843-2763.

(1) 2017 ASME Boiler and Pressure Vessel Code (BPVC), Section I, Rules for Construction of Power Boilers, 2017 Edition, July 1, 2017, incorporated by reference at §§250.851(a) and 250.1629(b).

(2) 2017 ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers, 2017 Edition, July 1, 2017, incorporated by reference at §§250.851(a) and 250.1629(b).

(3) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 1, 2017 Edition; July 1, 2017, incorporated by reference at §§250.851(a) and 250.1629(b).

(4) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 2: Alternative Rules, 2017 Edition, July 1, 2017, incorporated by reference at §§250.851(a) and 250.1629(b).

(5) 2017 ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Division 3: Alternative Rules for Construction of High Pressure Vessels, 2017 Edition, July 1, 2017, incorporated by reference at §§250.851(a) and 250.1629(b).

(g) 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: 1-877-909-2786:

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

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

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

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

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

(h) American Welding Society (AWS), AWS Codes, 8669 NW 36 Street, #130, Miami, FL 33126; *http://www.aws.org;*phone: 800-443-9353:

(1) AWS D1.1:2000, Structural Welding Code—Steel, 17th Edition, October 18, 1999; incorporated by reference at §250.901;

(2) AWS D1.4-98, Structural Welding Code—Reinforcing Steel, 1998 Edition; incorporated by reference at §250.901;

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

(i) National Association of Corrosion Engineers (NACE) International, NACE Standards, Park Ten Place, Houston, TX 77084; *http://www.nace.org;* phone: 281-228-6200:

(1) NACE Standard MR0175-2003, Standard Material Requirements, Metals for Sulfide Stress Cracking and Stress Corrosion Cracking Resistance in Sour Oilfield Environments, Revised January 17, 2003; incorporated by reference at §§250.490 and 250.901;

(2) NACE Standard RP0176-2003, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production; incorporated by reference at §250.901.

(j) International Organization for Standardization (ISO), 1, ch. de la Voie-Creuse, CP 56, CH-1211, Geneva 20, Switzerland; *www.iso.org;* phone: 41-22-749-01-11:

(1) ISO/IEC (International Electrotechnical Commission) 17011, Conformity assessment—General requirements for accreditation bodies accrediting conformity assessment bodies, First edition 2004-09-01; Corrected version 2005-02-15; incorporated by reference at §§250.1900, 250.1903, 250.1904, and 250.1922.

(2) ISO/IEC 17021-1, Conformity assessment—Requirements for bodies providing audit and certification of management systems—Part 1: Requirements, First Edition, June 2015, incorporated by reference at §250.730(d).

(3) [Reserved]

(k) Center for Offshore Safety (COS), 1990 Post Oak Blvd., Suite 1370, Houston, TX 77056; *www.centerforoffshoresafety.org;* phone: 832-495-4925.

(1) COS Safety Publication COS-2-01, Qualification and Competence Requirements for Audit Teams and Auditors Performing Third-party SEMS Audits of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§250.1900, 250.1903, 250.1904, and 250.1921.

(2) COS Safety Publication COS-2-03, Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§250.1900, 250.1903, 250.1904, and 250.1920.

(3) COS Safety Publication COS-2-04, Requirements for Accreditation of Audit Service Providers Performing SEMS Audits and Certification of Deepwater Operations, First Edition, Effective Date October 2012; incorporated by reference at §§250.1900, 250.1903, 250.1904, and 250.1922.

[84 FR 21969, May 15, 2019]

Back to Top

§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 BSEE uses the information. The associated BSEE 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 or for limited inspection; parts 30 CFR Parts 251, 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, Bureau of Safety and Environmental Enforcement, 45600 Woodland Road, Sterling, VA 20166.

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

30 CFR Subpart, title and/or BSEE Form (OMB Control No.)	BSEE collects this information and uses it to:
(1) Subpart A, General (1014-0022), including Forms BSEE-0011, iSEE; BSEE-0132, Evacuation Statistics; BSEE-0143, Facility/Equipment Damage Report; BSEE-1832, Notification of Incidents of Noncompliance	(i) Determine that activities on the OCS comply with statutory and regulatory requirements; are safe and protect the environment; and result in diligent development and production on OCS leases.
	(ii) Support the unproved and proved reserve estimation, resource assessment, and fair market value determinations.
	(iii) Assess damage and project any disruption of oil and gas production from the OCS after a major natural occurrence.
(2) Subpart B, Plans and Information (1014-0024)	Evaluate Deepwater Operations Plans for compliance with statutory and regulatory requirements
(3) Subpart C, Pollution Prevention and Control (1014-0023)	(i) Evaluate measures to prevent unauthorized discharge of pollutants into the offshore waters.
	(ii) Ensure action is taken to control pollution.
(4) Subpart D, Oil and Gas and Drilling Operations (1014-0018), including Forms BSEE-0125, End of Operations Report; BSEE-0133, Well Activity Report; and BSEE-0133S, Open Hole Data Report	(i) Evaluate the equipment and procedures to be used in drilling operations on the OCS.
	(ii) Ensure that drilling operations meet statutory and regulatory requirements.
(5) Subpart E, Oil and Gas Well-Completion Operations (1014-0004)	(i) Evaluate the equipment and procedures to be used in well-completion operations on the OCS.
	(ii) Ensure that well-completion operations meet statutory and regulatory requirements.
(6) Subpart F, Oil and Gas Well Workover Operations (1014-0001)	(i) Evaluate the equipment and procedures to be used during well-workover operations on the OCS.
	(ii) Ensure that well-workover operations meet statutory and regulatory requirements.
(7) Subpart G, Blowout Preventer Systems (1014-0028), including Form BSEE-0144, Rig Movement Notification Report	(i) Evaluate the equipment and procedures to be used during well drilling, completion, workover, and abandonment operations on the OCS.

	(ii) Ensure that well operations meet statutory and regulatory requirements.
(8) Subpart H, Oil and Gas Production Safety Systems (1014-0003)	(i) Evaluate the equipment and procedures that will be used during production operations on the OCS.
	(ii) Ensure that production operations meet statutory and regulatory requirements.
(9) Subpart I, Platforms and Structures (1014-0011)	(i) Evaluate the design, fabrication, and installation of platforms on the OCS.
	(ii) Ensure the structural integrity of platforms installed on the OCS.
(10) Subpart J, Pipelines and Pipeline Rights-of-Way (1014-0016), including Form BSEE-0149, Assignment of Federal OCS Pipeline Right-of-Way Grant	(i) Evaluate the design, installation, and operation of pipelines on the OCS.
	(ii) Ensure that pipeline operations meet statutory and regulatory requirements.
(11) Subpart K, Oil and Gas Production Rates (1014-0019), including Forms BSEE-0126, Well Potential Test Report and BSEE-0128, Semiannual Well Test Report	(i) Evaluate production rates for hydrocarbons produced on the OCS.
	(ii) Ensure economic maximization of ultimate hydrocarbon recovery.
(12) Subpart L, Oil and Gas Production Measurement, Surface Commingling, and Security (1014-0002)	(i) Evaluate the measurement of production, commingling of hydrocarbons, and site security plans.
	(ii) Ensure that produced hydrocarbons are measured and commingled to provide for accurate royalty payments and security.
(13) Subpart M, Unitization (1014-0015)	(i) Evaluate the unitization of leases.
	(ii) Ensure that unitization prevents waste, conserves natural resources, and protects correlative rights.
(14) 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).
(15) Subpart O, Well Control and Production Safety Training (1014-0008)	(i) Evaluate training program curricula for OCS workers, course schedules, and attendance.
	(ii) Ensure that training programs are technically accurate and sufficient to meet statutory and regulatory requirements, and that workers are properly trained.
(16) Subpart P, Sulfur Operations (1014-0006)	(i) Evaluate sulfur exploration and development operations on the OCS.
	(ii) Ensure that OCS sulfur operations meet statutory and regulatory requirements and will result in diligent development and production of sulfur leases.
(17) Subpart Q, Decommissioning Activities (1014-0010)	Ensure that decommissioning activities, site clearance, and platform or pipeline removal are properly performed to meet statutory and regulatory requirements and do not conflict with other users of the OCS.
(18) Subpart S, Safety and Environmental Management Systems (1014-0017), including Form BSEE-0131, Performance Measures Data	(i) Evaluate operators' policies and procedures to assure safety and environmental protection while conducting OCS operations (including those operations conducted by contractor and subcontractor personnel).
	(ii) Evaluate Performance Measures Data relating to risk and number of accidents, injuries, and oil spills during OCS activities.
(19) Application for Permit to Drill (APD, Revised APD), Form BSEE-0123; and Supplemental APD Information Sheet, Form BSEE-0123S, and all supporting documentation (1014-0025)	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling.
	(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.
(20) Application for Permit to Modify (APM), Form BSEE-0124, and supporting documentation (1014-0026)	(i) Evaluate and approve the adequacy of the equipment, materials, and/or procedures that the lessee or operator plans to use during drilling and to evaluate well plan modifications and changes in major equipment.
	(ii) Ensure that applicable OCS operations meet statutory and regulatory requirements.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26015, Apr. 29, 2016; 81 FR 36149, June 6, 2016]

Back to Top

Subpart B—Plans and Information

Back to Top

General Information

Back to Top

§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:

BOEM means Bureau of Ocean Energy Management of the Department of the Interior.

BSEE means Bureau of Safety and Environmental Enforcement of the Department of the Interior.

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.

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 BOEM for a decision (see 30 CFR 550.232(d) and 550.267(d)).

Modification means a change required by the Regional Supervisor to an EP, DPP, or DOCD (see 30 CFR 550.233(b)(2) and 550.270(b)(2)) that is pending before BOEM 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 a BSEE 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 BOEM has disapproved (see 30 CFR 550.234(b), 550.272(a), and 550.273(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 30 CFR 550.283(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 30 CFR 550.283(b)).

Back to Top

§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 BSEE 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) [Reserved]	
(2) [Reserved]	
(3) [Reserved]	
(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) [Reserved]	
(6) [Reserved]	

(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 BSEE;

(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 BSEE.

Back to Top

§§250.202-250.203 [Reserved]

Back to Top

§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.

Back to Top

§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.

Back to Top

Post-Approval Requirements for the EP, DPP, and DOCD

Back to Top

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

The Regional Supervisor may direct you to conduct monitoring programs. You must retain copies of all monitoring data obtained or derived from your monitoring programs and make them available to BSEE upon request. The

Regional Supervisor may require you to:

(a) *Monitoring plans.* Submit monitoring plans for approval before you begin 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.

Back to Top

Deepwater Operations Plan (DWOP)

Back to Top

§250.286 What is a DWOP?

(a) A DWOP is a plan that provides sufficient information for BSEE 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 BOEM Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents. BSEE 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.

Back to Top

§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 BSEE considers the technology of your project non-conventional, you must contact the Regional Supervisor for guidance.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 BSEE has approved the Conceptual Plan.

Back to Top

§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.

Back to Top

§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;

(p) If you propose to use a pipeline free standing hybrid riser (FSHR) on a permanent installation that utilizes a buoyancy air can suspended from the top of the riser, you must provide the following information in your DWOP in the discussions required by paragraphs (f) and (g) of this section:

(1) A detailed description and drawings of the FSHR, buoy, and the associated connection system;

(2) Detailed information regarding the system used to connect the FSHR to the buoyancy air can, and associated redundancies; and

(3) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and the associated connection system for fatigue, stress, and any other abnormal condition (e.g., corrosion) that may negatively impact the riser system's integrity.

(q) Payment of the service fee listed in §250.125.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

Back to Top

§250.293 What operations require approval of the DWOP?

You may not begin production until BSEE approves your DWOP.

Back to Top

§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.

Back to Top

§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.

Back to Top

Subpart C—Pollution Prevention and Control

Back to Top

§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 that 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. For Arctic OCS exploratory drilling, you must capture all petroleum-based mud to prevent its discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all water-based mud from operations after completion of the hole for the conductor casing to prevent its discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged mud may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged mud may adversely affect marine mammals, fish, or their habitat.

(2) You must obtain approval from the District Manager of the method you plan to use to dispose of drill cuttings, sand, and other well solids. For Arctic OCS exploratory drilling, you must capture all cuttings from operations that utilize petroleum-based mud to prevent their discharge into the marine environment. The Regional Supervisor may also require you to capture, during your Arctic OCS exploratory drilling operations, all cuttings from operations that utilize water-based mud after completion of the hole for the conductor casing to prevent their discharge into the marine environment, based on various factors including, but not limited to:

(i) The proximity of your exploratory drilling operation to subsistence hunting and fishing locations;

(ii) The extent to which discharged cuttings may cause marine mammals to alter their migratory patterns in a manner that impedes subsistence users' access to, or use of, those resources, or increases the risk of injury to subsistence users; or

(iii) The extent to which discharged cuttings may adversely affect marine mammals, fish, or their habitat.

(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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 46560, July 15, 2016]

Back to Top

§250.301 Inspection of facilities.

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.

Back to Top

Subpart D—Oil and Gas Drilling Operations

Back to Top

General Requirements

Back to Top

§250.400 General requirements.

Drilling operations must be conducted in a safe 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26017, Apr. 29, 2016]

Back to Top

§§250.401-250.403 [Reserved]

Back to Top

§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.

Back to Top

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

You must equip each diesel engine with an air intake 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36149, June 6, 2016]

Back to Top

§250.406 [Reserved]

Back to Top

§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.

Back to Top

§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 BSEE-0123) (see §250.414(h)). Procedures for obtaining approval are described in §250.141 of this part.

Back to Top

§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)).

Back to Top

Applying for a Permit To Drill

Back to Top

§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 553; and

(d) Submit the following to the District Manager:

(1) An original and two complete copies of Form BSEE-0123, Application for Permit to Drill (APD), and Form BSEE-0123S, Supplemental APD Information Sheet;

(2) A separate public information copy of forms BSEE-0123 and BSEE-0123S that meets the requirements of §250.186; and

(3) Payment of the service fee listed in §250.125.

Back to Top

§250.411 What information must I submit with my application?

In addition to forms BSEE-0123 and BSEE-0123S, you must include the information required in this subpart and subpart G of this part, including the following:

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 systems descriptions,	§250.416.
(f) BOP system descriptions,	§250.731.
(g) Requirements for using a MODU, and	§250.713.
(h) Additional information.	§250.418.

[81 FR 26017, Apr. 29, 2016]

Back to Top

§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.

Back to Top

§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 curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights (surface and downhole), planned safe drilling margin, 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

Back to Top

§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 that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

(1) Your safe drilling margin must also include use of equivalent downhole mud weight that is:

(i) Greater than the estimated pore pressure; and

(ii) Except as provided in paragraph (c)(2) of this section, a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.

(2) In lieu of meeting the criteria in paragraph (c)(1)(ii) of this section, you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight. You may submit such justification in advance of your full APD, and BSEE may consider such justification for approval when submitted. Any such approval will be contingent upon your confirmation in the APD that your plans and the information underlying your approved justification have not changed.

(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and analogous well behavior observations, if available.

(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 alternate procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternate procedures afford an equal or greater degree of protection, safety, or performance, or why the departures are requested;

(i) Projected plans for well testing (refer to §250.460);

(j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

(k) Any additional information required by the District Manager needed to clarify or evaluate your drilling prognosis.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26017, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

Back to Top

§250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

(a) The following well design information:

(1) Hole sizes;

(2) Bit depths (including measured and true vertical depth (TVD));

(3) Casing information, including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and

(4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

(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;

(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 (as incorporated by reference 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; and

(f) A written description of how you evaluated the best practices included in API Standard 65—Part 2, Isolating Potential Flow Zones During Well Construction, Second Edition (as incorporated by reference in §250.198). Your written description must identify the mechanical barriers and cementing practices you will use for each casing string (reference API Standard 65—Part 2, Sections 4 and 5).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50891, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016]

Back to Top

§250.416 What must I include in the diverter description?

You must include in the diverter description:

(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 element 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.

[81 FR 26018, Apr. 29, 2016]

Back to Top

§250.417 [Reserved]

Back to Top

§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 cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

(h) Certification of your casing and cementing program as required in §250.420(a)(7); and

(i) Such other information as the District Manager may require.

(j) For Arctic OCS exploratory drilling operations, you must provide the information required by §250.470.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 81 FR 46561, July 15, 2016]

Back to Top

Casing and Cementing Requirements

Back to Top

§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 applicable requirements of this subpart and of subpart G of this part.

(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;

(5) Support unconsolidated sediments;

(6) Provide adequate centralization consistent with the guidelines of API Standard 65—Part 2 (as incorporated by reference in §250.198); and

(7)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and §250.423. Submit this certification with your APD (Form BSEE-0123).

(ii) You must have the registered professional engineer involved in the casing and cementing design process.

(iii) The registered professional engineer must be registered in a state of the United States and have sufficient expertise and experience to perform the certification.

(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.

(3) On all wells that use subsea BOP stacks, you must include two independent barriers, including one mechanical barrier, in each annular flow path (examples of barriers include, but are not limited to, primary cement job and seal assembly). For the final casing string (or liner if it is your final string), you must install one mechanical barrier in addition to cement to prevent flow in the event of a failure in the cement. A dual float valve, by itself, is not considered a mechanical barrier. These barriers cannot be modified prior to or during completion or abandonment operations. The BSEE District Manager may approve alternative options under §250.141. You must submit documentation of this installation to BSEE in the End-of-Operations Report (Form BSEE-0125).

(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

(c) *Cementing requirements*. (1) 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 the casing or before commencing completion operations. (If a liner is used refer to §250.421(f)).

(2) You must use a weighted fluid during displacement to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26018, Apr. 29, 2016; 84 FR 21973, May 15, 2019]

Back to Top

§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 and set it above the encountered zone	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 well cellar, 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 measured depth (MD) 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 MD above the casing shoe and 500 feet MD 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 MD above the casing shoe and 500 feet MD above the uppermost hydrocarbon-bearing zone.
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet MD 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 MD above the previous casing shoe. You may not use a liner as conductor casing. A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.	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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26018, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

Back to Top

§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.

Back to Top

§250.423 What are the requirements for casing and liner installation?

You must ensure proper installation of casing in the subsea wellhead or liner in the liner hanger.

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the casing string.

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing the liner.

(c) You must perform a pressure test on the casing seal assembly to ensure proper installation of casing or liner. You must perform this test for the intermediate and production casing strings or liners.

(1) You must submit for approval with your APD, test procedures and criteria for a successful test.

(2) You must document all your test results and make them available to BSEE upon request.

[81 FR 26019, Apr. 29, 2016, as amended at 84 FR 21974, May 15, 2019]

Back to Top

§§250.424-250.426 [Reserved]

Back to Top

§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 §250.414. When you cannot maintain the safe drilling margin, you must:

(1) Suspend drilling operations and submit proposed remedial actions to the District Manager. The District Manager must review and approve your proposed remedial actions, which may include limited drilling through a lost circulation zone; or

(2) Notify the District Manager and take further action in accordance with API Bulletin 92L (as incorporated by reference in §250.198), if appropriate. You must submit a revised permit documenting any responsive actions taken.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26019, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

Back to Top

§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 change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) 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 and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job	(1) Locate the top of cement by: (i) Running a temperature survey;

(such as unplanned lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment),	(ii) Running a cement evaluation log; (iii) Using tracers in the cement and logging them prior to drill out; or (iv) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
(d) Inadequate cement job,	Comply with §250.428(c)(1) and take remedial actions. The District Manager must review and approve all remedial actions either through a previously approved contingency plan within the permit or remedial actions included in a revised permit before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program, that are not included in the approved permit, will require submittal of a certification by a professional engineer (PE) certifying that they have reviewed and approved the proposed changes. You must also meet any other requirements of the District Manager for remedial actions.
(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.
(k) Plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner,	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50892, Aug. 22, 2012; 81 FR 26019, Apr. 29, 2016; 84 FR 21974, May 15, 2019]

Back to Top

Diverter System Requirements

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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. For subsequent testing, you may partially actuate the diverter element and a flow test is not required.

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

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21975, May 15, 2019]

Back to Top

§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.

Back to Top

§§250.440-250.451 [Reserved]

Back to Top

§250.452 What are the real-time monitoring requirements for Arctic OCS exploratory drilling operations?

(a) When conducting exploratory drilling operations on the Arctic OCS, you must gather and monitor real-time data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's fluid handling systems on the rig; and

(3) The well's downhole conditions as monitored by a downhole sensing system, when such a system is installed.

(b) During well operations, you must transmit the data identified in paragraph (a) of this section as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel. Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After well operations, you must store the data at a designated location for recordkeeping purposes as required in §§250.740 and 250.741. You must provide BSEE with access to your real-time monitoring data onshore upon request.

[81 FR 46561, July 15, 2016]

Back to Top

Drilling Fluid Requirements

Back to Top

§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.

Back to Top

§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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26020, Apr. 29, 2016]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 (as incorporated by reference 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 (as incorporated by reference 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.

Back to Top

Other Drilling Requirements

Back to Top

§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 BSEE-0123) or in an Application for Permit to Modify (APM) (form BSEE-0124). 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.

Back to Top

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

For this subpart, BSEE 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 a 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 180 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.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21975, May 15, 2019]

Back to Top

§250.462 What are the source control, containment, and collocated equipment requirements?

For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor.

(a) To determine your required source control and containment capabilities you must do the following:

(1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well.

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well. SCCE means the capping stack, cap-and-flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels, which have the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment based on the determinations outlined in paragraph (a) of this section. This SCCE, supporting equipment, and collocated equipment may include, but is not limited to, the following:

(1) Subsea containment and capture equipment, including containment domes and capping stacks;

(2) Subsea utility equipment including hydraulic power sources and hydrate control equipment;

(3) Collocated equipment including dispersant injection equipment;

(4) Riser systems;

(5) Remotely operated vehicles (ROVs);

(6) Capture vessels;

(7) Support vessels; and

(8) Storage facilities.

(c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE-0123. The description of your containment capabilities must contain the following:

(1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor;

(2) A discussion of the determination required in paragraph (a) of this section; and

(3) Information showing that you have access to and the ability to deploy all equipment required by paragraph (b) of this section.

(d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your:

(1) Well design changes; or

(2) Approved source control and containment equipment is out of service.

(e) You must maintain, test, and inspect the source control, containment, and collocated equipment identified in the following table according to these requirements:

Equipment	Requirements, you must:	Additional information
(1) Capping stacks,	(i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests),	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure containing critical	Pressure containing critical components are

	components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and an independent third party.	those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing	
(2) Production safety systems used for flow and capture operations,	(i) Meet or exceed the requirements set forth in Subpart H, excluding required equipment that would be installed below the wellhead or that is not applicable to the cap and flow system.	
	(ii) Have all equipment unique to containment operations available for inspection at all times	
(3) Subsea utility equipment,	Have all equipment utilized solely for containment operations available for inspection at all times	Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.
(4) Collocated equipment designated by the operator in the Regional Containment Demonstration (RCD) or Well Containment Plan (WCP),	Have equipment available for inspection at all times	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.

[81 FR 26020, Apr. 29, 2016, as amended at 84 FR 21975, May 15, 2019]

Back to Top

§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.

Back to Top

Applying for a Permit To Modify and Well Records

Back to Top

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

(a) You must submit an APM (form BSEE-0124) or an End of Operations Report (form BSEE-0125) 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 BSEE-0124 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 BSEE-0124 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 BSEE-0124,	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 BSEE-0124 and BSEE-0125 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 BSEE-0124) 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 BSEE-0124 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 an End of Operations Report (EOR), Form BSEE-0125, as required under §250.744.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26021, Apr. 29, 2016]

Back to Top

§§250.466-250.469 [Reserved]

Back to Top

Additional Arctic OCS Requirements

Source: 81 FR 46561, July 15, 2016, unless otherwise noted.

Back to Top

§250.470 What additional information must I submit with my APD for Arctic OCS exploratory drilling operations?

In addition to complying with all other applicable requirements included in this part, you must provide with your APD all of the following information pertaining to your proposed Arctic OCS exploratory drilling:

(a) A detailed description of:

(1) The environmental, meteorological, and oceanic conditions you expect to encounter at the well site(s);

(2) How you will prepare your equipment, materials, and drilling unit for service in the conditions identified in paragraph (a)(1) of this section, and how your drilling unit will be in compliance with the requirements of §250.713.

(b) A detailed description of all operations necessary in Arctic OCS conditions to transition the rig from being under way to conducting drilling operations and from ending drilling operations to being under way, as well as any anticipated repair and maintenance plans for the drilling unit and equipment. You should include, among other things, a description of how you plan to:

(1) Recover the subsea equipment, including the marine riser and the lower marine riser package;

(2) Recover the BOP;

(3) Recover the auxiliary sub-sea controls and template;

(4) Lay down the drill pipe and secure the drill pipe and marine riser;

(5) Secure the drilling equipment;

(6) Transfer the fluids for transport or disposal;

(7) Secure ancillary equipment like the draw works and lines;

(8) Refuel or transfer fuel;

(9) Offload waste;

(10) Recover the Remotely Operated Vehicles;

(11) Pick up the oil spill prevention booms and equipment; and

(12) Offload the drilling crew.

(c) A description of well-specific drilling objectives, timelines, and updated contingency plans for temporary abandonment of the well, including but not limited to the following:

(1) When you will spud the particular well (*i.e.,* begin drilling operations at the well site) identified in the APD;

(2) How long you will take to drill the well;

(3) Anticipated depths and geologic targets, with timelines;

(4) When you expect to set and cement each string of casing;

(5) When and how you would log the well;

(6) Your plans to test the well;

(7) When and how you intend to abandon the well, including specifically addressing your plans for how to move the rig off location and how you will meet the requirements of §250.720(c);

(8) A description of what equipment and vessels will be involved in the process of temporarily abandoning the well due to ice; and

(9) An explanation of how you will integrate these elements into your overall program.

(d) A detailed description of your weather and ice forecasting capability for all phases of the drilling operation, including:

(1) How you will ensure your continuous awareness of potential weather and ice hazards at, and during transition between, wells;

(2) Your plans for managing ice hazards and responding to weather events; and

(3) Verification that you have the capabilities described in your BOEM-approved EP.

(e) A detailed description of how you will comply with the requirements of §250.472.

(f) A statement that you own, or have a contract with a provider for, source control and containment equipment (SCCE), which is capable of controlling and/or containing a worst case discharge, as described in your BOEM-approved EP, when proposing to use a MODU to conduct exploratory drilling operations on the Arctic OCS. The following information must be included in your SCCE submittal:

(1) A detailed description of your or your contractor's SCCE capability to stop or contain flow from an out-of-control well, including your operating assumptions and limitations; your access to and ability to deploy, in accordance with §250.471, all necessary SCCE; and your ability to evaluate the performance of the well design to determine how you can achieve a full shut-in without having reservoir fluids discharged into the environment;

(2) An inventory of the local and regional SCCE, supplies, and services that you own or for which you have a contract with a provider. You must identify each supplier of such equipment and services and provide their locations and telephone numbers;

(3) Where applicable, proof of contracts or membership agreements with cooperatives, service providers, or other contractors who will provide you with the necessary SCCE or related supplies and services if you do not possess them. The contract or membership agreement must include provisions for ensuring the availability of the personnel and/or equipment on a 24-hour per day basis while you are drilling below or working below the surface casing;

(4) A detailed description of the procedures you plan to use to inspect, test, and maintain your SCCE; and

(5) A detailed description of your plan to ensure that all members of your operating team, who are responsible for operating the SCCE, have received the necessary training to deploy and operate such equipment in Arctic OCS conditions and demonstrate ongoing proficiency in source control operations. You must also identify and include the dates of prior and planned training.

(g) Where it does not conflict with other requirements of this subpart, and except as provided in paragraphs (g)(1) through (11) of this section, you must comply with the requirements of API RP 2N, Third Edition “Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions” (incorporated by reference as specified in §250.198), and provide a detailed description of how you will utilize the best practices included in API RP 2N during your exploratory drilling operations. You are not required to incorporate the following sections of API RP 2N into your drilling operations:

(1) Sections 6.6.3 through 6.6.4;

(2) The foundation recommendations in Section 8.4;

(3) Section 9.6;

(4) The recommendations for permanently moored systems in Section 9.7;

(5) The recommendations for pile foundations in Section 9.10;

(6) Section 12;

(7) Section 13.2.1;

(8) Sections 13.8.1.1, 13.8.2.1, 13.8.2.2, 13.8.2.4 through 13.8.2.7;

(9) Sections 13.9.1, 13.9.2, 13.9.4 through 13.9.8;

(10) Sections 14 through 16; and

(11) Section 18.

Back to Top

§250.471 What are the requirements for Arctic OCS source control and containment?

You must meet the following requirements for all exploration wells drilled on the Arctic OCS:

(a) If you use a MODU when drilling below or working below the surface casing, you must have access to the following SCCE capable of stopping or capturing the flow of an out-of-control well:

(1) A capping stack, positioned to ensure that it will arrive at the well location within 24 hours after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section;

(2) A cap and flow system, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The cap and flow system must be designed to capture at least the amount of hydrocarbons equivalent to the calculated worst case discharge rate referenced in your BOEM-approved EP; and

(3) A containment dome, positioned to ensure that it will arrive at the well location within 7 days after a loss of well control and can be deployed as directed by the Regional Supervisor pursuant to paragraph (h) of this section. The containment dome must have the capacity to pump fluids without relying on buoyancy.

(b) You must conduct a monthly stump test of dry-stored capping stacks. If you use a pre-positioned capping stack, you must conduct a stump test prior to each installation on each well.

(c) As required by §250.465(a), if you propose to change your well design, you must submit an APM. For Arctic OCS operations, your APM must include a reevaluation of your SCCE capabilities for any new Worst Case Discharge (WCD) rate, and a demonstration that your SCCE capabilities will meet the criteria in §250.470(f) under the changed well design.

(d) You must conduct tests or exercises of your SCCE, including deployment of your SCCE, when directed by the Regional Supervisor.

(e) You must maintain records pertaining to testing, inspection, and maintenance of your SCCE for at least 10 years and make the records available to any authorized BSEE representative upon request.

(f) You must maintain records pertaining to the use of your SCCE during testing, training, and deployment activities for at least 3 years and make the records available to any authorized BSEE representative upon request.

(g) Upon a loss of well control, you must initiate transit of all SCCE identified in paragraph (a) of this section to the well.

(h) You must deploy and use SCCE when directed by the Regional Supervisor.

(i) Operators may request approval of alternate procedures or equipment to the SCCE requirements of subparagraph (a) of this section in accordance with §250.141. The operator must show and document that the alternate procedures or equipment will provide a level of safety and environmental protection that will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate procedures or equipment will be capable of stopping or capturing the flow of an out-of-control well.

Back to Top

§250.472 What are the relief rig requirements for the Arctic OCS?

(a) In the event of a loss of well control, the Regional Supervisor may direct you to drill a relief well using the relief rig able to kill and permanently plug an out-of-control well as described in your APD. Your relief rig must comply with all other requirements of this part pertaining to drill rig characteristics and capabilities, and it must be able to drill a relief well under anticipated Arctic OCS conditions.

(b) When you are drilling below or working below the surface casing during Arctic OCS exploratory drilling operations, you must have access to a relief rig, different from your primary drilling rig, staged in a location such that it can arrive on site, drill a relief well, kill and abandon the original well, and abandon the relief well prior to expected seasonal ice encroachment at the drill site, but no later than 45 days after the loss of well control.

(c) Operators may request approval of alternative compliance measures to the relief rig requirement in accordance with §250.141. The operator must show and document that the alternate compliance measure will meet or exceed the level of safety and environmental protection required by BSEE regulations, including demonstrating that the alternate compliance measure will be able to kill and permanently plug an out-of-control well.

Back to Top

§250.473 What must I do to protect health, safety, property, and theenvironment while operating on the Arctic

OCS?

In addition to the requirements set forth in §250.107, when conducting exploratory drilling operations on the Arctic OCS, you must protect health, safety, property, and the environment by using the following:

(a) Equipment and materials that are rated or de-rated for service under conditions that can be reasonably expected during your operations; and

(b) Measures to address human factors associated with weather conditions that can be reasonably expected during your operations including, but not limited to, provision of proper attire and equipment, construction of protected work spaces, and management of shifts.

Back to Top

Hydrogen Sulfide

Back to Top

§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 BSEE 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 (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 BSEE 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_2concentration 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 (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 BSEE in the event of an H_2S release?* You must notify BSEE 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 (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.

Back to Top

Subpart E—Oil and Gas Well-Completion Operations

Back to Top

§250.500 General requirements.

Well-completion operations must 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26021, Apr. 29, 2016]

Back to Top

§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.

Back to Top

§250.502 [Reserved]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§§250.506-250.508 [Reserved]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 BSEE-0123 and BSEE-0123S), 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 BSEE-0124) for approval of such operations.

(b) You must submit the following with Form BSEE-0124 (or with Form BSEE-0123; Form BSEE-0123S):

(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) All applicable information required in §250.731.

(5) 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

(6) 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 BSEE-0125), including a schematic of the tubing and subsurface equipment.

(d) You must submit public information copies of Form BSEE-0125 according to §250.186.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

Back to Top

§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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50894, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

Back to Top

§§250.515-250.517 [Reserved]

Back to Top

§250.518 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) When the tree is installed, you must equip wells to monitor for casing pressure according to the following chart:

If you . . .	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.

(c) 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.

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§250.810 through 250.839.

(e) When installed, packers and bridge plugs must meet the following:

(1) The uppermost permanently installed packer and all permanently installed bridge plugs qualified as mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in §250.198);

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

(g) You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012, as amended at 81 FR 26021, Apr. 29, 2016; 81 FR 61918, Sept. 7, 2016; 84 FR 21976, May 15, 2019]

Back to Top

Casing Pressure Management

Back to Top

§250.519 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 (as incorporated by reference in §250.198) and the requirements of §§250.519 through 250.531. 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.

[84 FR 21976, May 15, 2019]

Back to Top

§250.520 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.521 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.522 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 §§250.521 and 250.523.

[84 FR 21976, May 15, 2019]

Back to Top

§250.523 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.524 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.525 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 $\frac{1}{2}$ -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 §250.522;

(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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012; 84 FR 21976, May 15, 2019]

Back to Top

§250.526 What do I submit if my casing diagnostic test requires action?

Within 14 days after you perform a casing diagnostic test requiring action under §250.525:

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 §250.527,	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	

		§250.528.	

[84 FR 21976, May 15, 2019]

Back to Top

§250.527 What must I include in my notification of corrective action?

The following information must be included in the notification of corrective action:

(a) Lessee or Operator name;

(b) Area name and OCS block number;

(c) Well name and API number; and

(d) Casing diagnostic test data.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.528 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 H_2S 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.529   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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

§250.530   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 §250.523(e).

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012, as amended at 84 FR 21976, May 15, 2019]

Back to Top

§250.531   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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50894, Aug. 22, 2012]

Back to Top

Subpart F—Oil and Gas Well-Workover Operations

Back to Top

§250.600   General requirements.

Well-workover operations must 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. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G of this part.

[81 FR 26021, Apr. 29, 2016]

Back to Top

§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.

(m) Acid treatments.

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

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21976, May 15, 2019]

Back to Top

§250.602 [Reserved]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§§250.606-250.608 [Reserved]

Back to Top

§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.

Back to Top

§250.610 Diesel engine air intakes.

You must equip diesel engine air intakes with a device to shut down the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with remotely operated, manual, or automatic shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic shutdown devices.

[81 FR 36149, June 6, 2016]

Back to Top

§250.611 Traveling-block safety device.

You must equip all units being used for well-workover operations that have both a traveling block and a crown block with a safety device that is designed to prevent the traveling block from striking the crown block. You must check the device for proper operation weekly and after each drill-line slipping operation. You must enter the results of the operational check in the operations log.

[81 FR 36149, June 6, 2016]

Back to Top

§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.

Back to Top

§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 BSEE-0124, Application for Permit to Modify.

(b) You must submit the following with Form BSEE-0124:

(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) All information required in §250.731.

(4) Where the well-workover is in a zone known to contain H_2S or a zone where the presence of H2S is unknown, information pursuant to §250.490 of this part; and

(5) Payment of the service fee listed in §250.125.

(c) The following additional information shall be submitted with Form BSEE-0124 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 BSEE-0124, 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 BSEE-0125, 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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50895, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

Back to Top

§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.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50895, Aug. 22, 2012; 81 FR 26021, Apr. 29, 2016]

Back to Top

§§250.615-250.618 [Reserved]

Back to Top

§250.619 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) 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.

(c) 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.

(d) Subsurface safety equipment must be installed, maintained, and tested in compliance with the applicable sections in §§250.810 through 250.839.

(e) If you pull and reinstall packers and bridge plugs, you must meet the following requirements:

(1) The uppermost permanently installed packer and all permanently installed bridge plugs qualified as

mechanical barriers must comply with ANSI/API Spec. 11D1 (as incorporated by reference in §250.198).

(2) The production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

(3) The production packer must be set as close as practically possible to the perforated interval; and

(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

(f) Your APM must include a description and calculations for how you determined the production packer setting depth.

(g) You must have two independent barriers, one being mechanical, in the exposed center wellbore prior to removing the tree and/or well control equipment.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50895, Aug. 22, 2012, as amended at 81 FR 26021, Apr. 29, 2016; 81 FR 61918, Sept. 7, 2016; 84 FR 21976, May 15, 2019]

Back to Top

§250.620 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.

[76 FR 64462, Oct. 18, 2011. Redesignated at 77 FR 50895, Aug. 22, 2012]

Back to Top

Subpart G—Well Operations and Equipment

Source: 81 FR 26022, Apr. 29, 2016, unless otherwise noted.

Back to Top

General Requirements

Back to Top

§250.700 What operations and equipment does this subpart cover?

This subpart covers operations and equipment associated with drilling, completion, workover, and decommissioning activities. This subpart includes regulations applicable to drilling, completion, workover, and decommissioning activities in addition to applicable regulations contained in subparts D, E, F, and Q of this part unless explicitly stated otherwise.

Back to Top

§250.701 May I use alternate procedures or equipment during operations?

You may use alternate procedures or equipment during operations after receiving approval as described in §250.141. You must identify and discuss your proposed alternate procedures or equipment in your Application for Permit to Drill (APD) (Form BSEE-0123) (see §250.414(h)) or your Application for Permit to Modify (APM) (Form BSEE-0124). Procedures for obtaining approval of alternate procedures or equipment are described in §250.141.

Back to Top

§250.702 May I obtain departures from these requirements?

You may apply for a departure from these requirements as described in §250.142. Your request must include a justification showing why the departure is necessary. You must identify and discuss the departure you are requesting in your APD (see §250.414(h)) or your APM.

Back to Top

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

You must take the necessary precautions to keep wells under control at all times, including:

(a) Use recognized engineering practices to reduce risks to the lowest level practicable when monitoring and evaluating well conditions and to minimize the potential for the well to flow or kick;

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

(c) Ensure that the toolpusher, operator's representative, or a member of the rig crew maintains continuous surveillance on the rig floor from the beginning of 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 subparts O and S of this part;

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

(f) Use equipment that has been designed, tested, and rated for the maximum environmental and operational conditions to which it may be exposed while in service.

Back to Top

Rig Requirements

Back to Top

§250.710 What instructions must be given to personnel engaged in well operations?

Prior to engaging in well operations, personnel must be instructed in:

(a) *Hazards and safety requirements.* You must instruct your personnel regarding the safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. The date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives.

(b) *Well control.* You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

Back to Top

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

You must conduct a weekly well-control drill with all personnel engaged in well operations. Your drill must familiarize personnel engaged in well operations with their roles and functions so that they can perform their duties promptly and efficiently as outlined in the well-control plan required by §250.710.

(a) *Timing of drills.* You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively with the same crew.

(b) *Recordkeeping requirements.* For each drill, you must record the following in the daily report:

(1) Date, time, and type of drill conducted;

(2) The amount of time it took to be ready to close the diverter or use each well-control component of BOP system; and

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

(c) *A BSEE ordered drill.* A BSEE representative may require you to conduct a well-control drill during a BSEE inspection. The BSEE representative will consult with your onsite representative before requiring the drill.

Back to Top

§250.712 What rig unit movements must I report?

(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE-0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 24 hours before:

(1) The arrival of a rig unit on location;

(2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE-0144; or

(3) The departure of a rig unit 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) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager:

(1) Where the MODU or platform rig is coming from;

(2) The location where the MODU or platform rig will be positioned;

(3) Whether the MODU or platform rig will be manned or unmanned; and

(4) If the location for stacking the MODU or platform rig changes.

(d) Prior to resuming operations after stacking, you must notify the appropriate District Manager of any construction, repairs, or modifications associated with the drilling package made to the MODU or platform rig.

(e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

(f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE-0144, Rig Movement Notification Report.

(g) You are not required to report rig unit movements to and from the safe zone during the course of permitted operations.

(h) If a rig unit is already on a well, you are not required to report any additional rig unit movements on that well.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21976, May 15, 2019]

Back to Top

§250.713 What must I provide if I plan to use a mobile offshore drilling unit (MODU) for well operations?

If you plan to use a MODU for well operations, you must provide:

(a) *Fitness requirements.* Information and data to demonstrate the MODU's capability to perform at the proposed location. This information must include the maximum environmental and operational conditions that the MODU 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 or APM, the District Manager may approve your APD or APM, but require you to collect and report this information during operations. Under this circumstance, the District Manager may revoke the approval of the APD or APM if information collected during operations shows that the MODU is not capable of performing at the proposed location.

(b) *Foundation requirements.* Information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed bottom-founded MODU. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM for that well location and conditions, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD or APM if additional information is needed to make a determination that the conditions are capable of supporting the MODU, or equipment installed on a subsea wellhead. For a moored rig, you must submit a plat of the rig's anchor pattern approved in your EP, DPP, or DOCD in your APD or APM.

(c) *For frontier areas.* (1) If the design of the MODU 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 MODU design. If required, you must obtain a third-party review of your MODU similar to the process outlined in §§250.915 through 250.918. You may submit this information before submitting an APD or APM.

(2) If you plan to conduct operations in a frontier area, you must have a contingency plan that addresses design and operating limitations of the MODU. 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 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) *Additional documentation.* You must provide the current Certificate of Inspection (for U.S.-flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

(e) *Dynamically positioned MODU.* If you use a dynamically positioned MODU, you must include in your APD or APM your contingency plan for moving off location in an emergency situation. At a minimum, your plan must address emergency events caused by storms, currents, station-keeping failures, power failures, and losses of well control. The District Manager may require your plan to include additional events that may require movement of the MODU and other information needed to clarify or further address how the MODU will respond to emergencies or other events.

(f) *Inspection of MODU.* The MODU must be available for inspection by the District Manager before commencing operations and at any time during operations.

(g) *Current monitoring.* For water depths greater than 400 meters (1,312 feet), you must include in your APD or APM:

(1) A description of the specific current speeds that will cause you to implement rig shutdown, move-off procedures, or both; and

(2) A discussion of the specific measures you will take to curtail rig operations and move off location when such currents are encountered. You may use criteria, such as current velocities, riser angles, watch circles, and remaining rig power to describe when these procedures or measures will be implemented.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§250.714   Do I have to develop a dropped objects plan?

If you use a floating rig unit in an area with subsea infrastructure, you must develop a dropped objects plan and make it available to BSEE upon request. This plan must be updated as the infrastructure on the seafloor changes. Your plan must include:

(a) A description and plot of the path the rig will take while running and pulling the riser;

(b) A plat showing the location of any subsea wells, production equipment, pipelines, and any other identified debris;

(c) Modeling of a dropped object's path with consideration given to metocean conditions for various material forms, such as a tubular (e.g., riser or casing) and box (e.g., BOP or tree);

(d) Communications, procedures, and delegated authorities established with the production host facility to shut-in any active subsea wells, equipment, or pipelines in the event of a dropped object; and

(e) Any additional information required by the District Manager as appropriate to clarify, update, or evaluate your dropped objects plan.

Back to Top

§250.715   Do I need a global positioning system (GPS) for all MODUs?

All MODUs must have a minimum of two functioning GPS transponders at all times, and you must provide to BSEE real-time access to the GPS data prior to and during each hurricane season.

(a) The GPS must be capable of monitoring the position and tracking the path in real-time if the MODU moves from its location during a severe storm.

(b) You must install and protect the tracking system's equipment to minimize the risk of the system being disabled.

(c) You must place the GPS transponders in different locations for redundancy to minimize risk of system failure.

(d) Each GPS transponder must be capable of transmitting data for at least 7 days after a storm has passed.

(e) If the MODU is moved off location in the event of a storm, you must immediately begin to record the GPS location data.

(f) You must contact the Regional Office and allow real-time access to the MODU location data. When you contact the Regional Office, provide the following:

(1) Name of the lessee and operator with contact information;

(2) MODU name;

(3) Initial date and time; and

(4) How you will provide GPS real-time access.

Back to Top

Well Operations

Back to Top

§250.720 When and how must I secure a well?

(a) Whenever you interrupt operations, you must notify the District Manager. Before moving off the well, you must have two independent barriers installed, at least one of which must be a mechanical barrier, as approved by the District Manager. You must install the barriers at appropriate depths within a properly cemented casing string or liner. Before removing a subsea BOP stack or surface BOP stack on a mudline suspension well, you must conduct a negative pressure test in accordance with §250.721.

(1) The events that would cause you to interrupt operations and notify the District Manager include, but are not limited to, the following:

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

(iii) Repair to major rig or well-control equipment;

(iv) Observed flow outside the well's casing (e.g., shallow water flow or bubbling); or

(v) Impending National Weather Service-named tropical storm or hurricane.

(2) The District Manager may approve alternate procedures or barriers, in accordance with §250.141, if you do not have time to install the required barriers or if special circumstances occur.

(3) If you unlatch the BOP or LMRP:

(i) Upon relatch of the BOP, you must test according to §250.734(b)(2), or

(ii) Upon relatch of the LMRP, you must test according to §250.734(b)(3); and

(iii) You must submit a revised permit with a written statement from an independent third party certifying that the previous certification under §250.731(c) remains valid and receive District Manager approval before resuming operations.

(b) Before you displace kill-weight fluid from the wellbore and/or riser, thereby creating an underbalanced state, you must obtain approval from the District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight fluid and provide detailed step-by-step written procedures describing how you will safely displace these fluids. The step-by-step displacement procedures must address the following:

(1) Number and type of independent barriers, as described in §250.420(b)(3), that are in place for each flow path that requires such barriers;

(2) Tests you will conduct to ensure integrity of independent barriers;

(3) BOP procedures you will use while displacing kill-weight fluids; and

(4) Procedures you will use to monitor the volumes and rates of fluids entering and leaving the wellbore.

(c) For Arctic OCS exploratory drilling operations, in addition to the requirements of paragraphs (a) and (b) of this section:

(1) If you move your drilling rig off a well prior to completion or permanent abandonment, you must ensure that any equipment left on, near, or in a wellbore that has penetrated below the surface casing is positioned in a manner to:

(i) Protect the well head; and

(ii) Prevent or minimize the likelihood of compromising the down-hole integrity of the well or the effectiveness of the well plugs.

(2) In areas of ice scour you must use a well mudline cellar or an equivalent means of minimizing the risk of damage to the well head and wellbore. BSEE may approve an equivalent means that will meet or exceed the level of safety and environmental protection provided by a mudline cellar if the operator can show that utilizing a mudline cellar would compromise the stability of the rig, impede access to the well head during a well control event, or otherwise create operational risks.

(d) You must have the equipment used solely for intervention operations (e.g., tree interface tools) identified, readily available, properly maintained, and available for BSEE inspection upon request. This equipment is required for subsea completed wells with a tree installed, that meet the following conditions:

(1) Have a shut-in tubing pressure that is greater than the hydrostatic pressure of the water column, or

(2) Are not capable of having the annulus monitored.

[81 FR 26022, Apr. 29, 2016, as amended at 81 FR 46563, July 15, 2016; 84 FR 21976, May 15, 2019]

Back to Top

§250.721 What are the requirements for pressure testing casing and liners?

(a) You must test each casing string that extends to the wellhead according to the following table:

Casing type	Minimum test pressure
(1) Drive or Structural,	Not required.
(2) Conductor, excluding subsea wellheads,	250 psi.
(3) Surface, Intermediate, and Production,	70 percent of its minimum internal yield.

(b) You must test each drilling liner and liner-top to a pressure at least equal to the anticipated leak-off pressure of the formation below that liner shoe, or subsequent liner shoes if set. You must conduct this test before you continue operations in the well.

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

(d) The District Manager may approve or require other casing test pressures as appropriate under the circumstances to ensure casing integrity.

(e) If you plan to produce a well, you must:

(1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before perforating the casing or liner; or

(2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure, not to exceed 70% of the burst rating limit of the weakest component before you drill the open-hole section.

(f) You may not resume 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 submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

(g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

(1) You must perform a negative pressure test on your final casing string or liner. This test must be conducted after setting your second barrier just above the shoe track, but prior to conducting any completion operations.

(2) You must perform a negative pressure test prior to unlatching the BOP at any point in the well. The negative pressure test must be performed on those components, at a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

(3) The District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack as appropriate to demonstrate casing or liner integrity.

(4) You must submit for approval with your APD or APM, test procedures and criteria for a successful negative pressure test. If any of your test procedures or criteria for a successful test change, you must submit for approval the changes in a revised APD or APM.

(5) You must document all your test results and make them available to BSEE upon request.

(6) If you have any indication of a failed negative pressure test, such as, but not limited to, pressure buildup or observed flow, you must immediately investigate the cause. If your investigation confirms that a failure occurred during the negative pressure test, you must:

(i) Correct the problem and immediately notify the appropriate District Manager; and

(ii) Submit a description of the corrective action taken and receive approval from the appropriate District Manager for the retest.

(7) You must have two barriers in place, as described in §250.420(b)(3), at any time and for any well, prior to performing the negative pressure test.

(8) You must include documentation of the successful negative pressure test in the End-of-Operations Report (Form BSEE-0125).

Back to Top

§250.722 What are the requirements for prolonged operations in a well?

If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner, you must:

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

(1) Evaluate the well casing with a pressure test, caliper tool, or imaging tool. On a case-by-case basis, the District Manager may require a specific method of evaluation of the effects on the well casing of prolonged operations; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that indicate the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used. District Manager approval is not required to resume operations if you conducted a successful pressure test as approved in your permit. You must document the successful pressure test in the WAR.

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

(1) Obtain approval from the District Manager to begin repairs or install additional casing. To obtain approval, you must also provide a PE certification showing that he or she reviewed and approved the proposed changes;

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

(3) Perform a pressure test after the repairs are made or additional casing is installed and report the results to the District Manager as specified in §250.721.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

Back to Top

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

You must take the following safety measures when you conduct operations with a rig unit on or jacked-up over a platform with producing wells or that has other hydrocarbon flow:

(a) The movement of rig units and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, must be conducted in a safe manner;

(b) You must install an emergency shutdown station for the production system near the rig operator's console;

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

(1) You move a rig unit 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 rig unit between wells on a platform; or

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

(d) All wells in the same well-bay which are capable of producing hydrocarbons must 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 rig units and related equipment, unless otherwise approved by the District Manager.

(1) 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.

(2) The well to which a rig unit or related equipment is to be moved must be equipped with a back-pressure valve prior to removing the tree and installing and testing the BOP system.

(3) The well from which a rig unit or related equipment is to be moved must be equipped with a back pressure valve prior to removing the BOP system and installing the production tree.

(e) Coiled tubing units, snubbing units, or wireline units may be moved onto and off of a platform without shutting in wells.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21977, May 15, 2019]

Back to Top

§250.724 What are the real-time monitoring requirements?

(a) When conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

(2) The well's active fluid circulating system; and

(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section.

(c) You must develop and implement a real-time monitoring plan. Your real-time monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following:

(1) A description of your real-time monitoring capabilities, including the types of the data collected;

(2) A description of how your real-time monitoring data will be transmitted during operations, how the data will be labeled and monitored by qualified personnel, and how the data will be stored as required in §§250.740 and 250.741;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data;

(4) The qualifications of the personnel monitoring the data;

(5) Your procedures for, and methods of, communication between rig personnel and the monitoring personnel; and

(6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig personnel and monitoring personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring capabilities or communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

[84 FR 21977, May 15, 2019]

Back to Top

Blowout Preventer (BOP) System Requirements

Back to Top

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

(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working-pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be determined at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements:

(1) The BOP requirements of API Standard 53 (incorporated by reference in §250.198) and the requirements of §§250.733 through 250.739. If there is a conflict between API Standard 53 and the requirements of this subpart, you must follow the requirements of this subpart.

(2) The provisions of the following industry standards (all incorporated by reference in §250.198) that apply to BOP systems:

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, at the proposed regulator settings of the BOP control system.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will require changes to your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, applicable Original Equipment Manufacturer's (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training recommendations unless otherwise directed by BSEE.

(c) You must follow the failure reporting procedures contained in API Standard 53, (incorporated by reference in §250.198), and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs (OORP), unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, and the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are started within 120 days of the failure to determine the cause of the failure, and are completed within 120 days upon starting the investigation and failure analysis. You must also ensure that the results and any corrective action are documented. You must ensure that the analysis report is submitted to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section, as well as the manufacturer. If you cannot complete the investigation and analysis within the specified time, you must submit an extension request detailing how you will complete the investigation and analysis to BSEE for approval. You must submit the extension request to the Chief, OORP.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief OORP, unless BSEE has designated a third party as provided in paragraph (c)(4) of this section.

(4) Submit notices and reports to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166. BSEE may designate a third party to receive the data and reports on behalf of BSEE. If BSEE designates a third party, you must submit the data and reports to the designated third party.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an ANSI/API Spec. Q1 (as incorporated by reference in §250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO/IEC 17021-1 (as incorporated by reference in §250.198).

(1) BSEE may consider accepting equipment manufactured under quality assurance programs other than ANSI/API Spec. Q1, provided you submit a request to the Chief, OORP for approval, containing relevant information about the alternative program.

(2) You must submit this request to the Chief, OORP; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia 20166.

[84 FR 21977, May 15, 2019]

Back to Top

§250.731 What information must I submit for BOP systems and system components?

For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission.

You must submit:	Including:
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment;
	(2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures);
	(3) Rated capacities for liquid and gas for the fluid-gas separator system;
	(4) Control fluid volumes needed to close, seal, and open each component;
	(5) Control system pressure and regulator settings needed to close each ram BOP under MASP as defined for the operation;

	(6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);
	(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations);
	(8) All locking devices; and
	(9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings,	(1) The inside diameter of the BOP stack;
	(2) Number and type of preventers (including blade type for shear ram(s));
	(3) All locking devices;
	(4) Size range for variable bore ram(s);
	(5) Size of fixed ram(s);
	(6) All control systems with all alarms and set points labeled, including pods;
	(7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP);
	(8) Associated valves of the BOP system;
	(9) Control station locations; and
	(10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.
(c) Certification by an independent third party,	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in §250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system; and (4) If using a subsea BOP, a BOP in an HPHT environment as defined in §250.804(b), or a surface BOP on a floating facility, the BOP has not been compromised or damaged from previous service.
(d) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21978, May 15, 2019]

Back to Top

§250.732 What are the independent third party requirements for BOP systems and system components?

(a) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third party and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

You must submit verification and documentation related to:	That:
(1) Shear testing,	(i) Demonstrates that the BOP will shear the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well;
	(ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;
	(iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines and any electric-, wire-, and slick-line to be used in the well;
	(iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram;
	(v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior

	control lines and any electric-, wire-, and slick-line to be used in the well; and
	(vi) Includes relevant testing results.
(2) Pressure integrity testing for sealing components, and	(i) Shows that testing is conducted after the shearing is completed and prior to opening the component;
	(ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 5 minutes; and
	(iii) Includes all relevant test results.
(3) Calculations	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(b) The independent third-party must be a technical classification society, a licensed professional engineering firm, or a registered professional engineer capable of providing the required certifications and verifications.

(c) For wells in an HPHT environment, as defined by §250.804(b), you must submit verification by an independent third party that it conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the independent third party access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

You must submit:	Including:
(1) Verification that the independent third party conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,	
(2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible,	(i) Identification of all reasonable potential modes of failure; and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
(3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and	
(4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.	For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

(d) You must make all documentation that demonstrates compliance with the requirements of this section available to BSEE upon request.

[84 FR 21978, May 15, 2019]

Back to Top

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

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. Prior to April 29, 2021, if your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

(2) The two BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except for tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(b) If you plan to use a surface BOP on a floating production facility you must:

(1) On new floating production facilities installed after April 29, 2021, that include a surface BOP, follow the BOP requirements in §250.734(a)(1).

(2) For risers installed after July 28, 2016, use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in §250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

(i) For a dual bore riser configuration, the annulus between the risers must be monitored for pressure during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.

(ii) The inner riser for a dual riser configuration is subject to the requirements at §250.721 for testing the casing or liner.

(c) You must install separate side outlets on the BOP stack for the kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets. The outlet valves must hold pressure from both directions.

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. 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) Additional requirements for surface BOP systems used in well-completion, workover, and decommissioning operations. The minimum BOP system for well-completion, workover, and decommissioning 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 pipe, work string, or tubing,	At least one set of pipe rams that are capable of sealing around each size of drill pipe, work string, or tubing. 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 pipe, work string, or tubing. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a surface BOP on a floating facility,	The elements required by §250.733(b)(1) of this part.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21979, May 15, 2019]

Back to Top

§250.734 What are the requirements for a subsea BOP system?

(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements.

When operating with a subsea BOP system, you must:	Additional requirements:
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than April 29, 2021.
	(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.
	(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools,

	and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing and associated exterior control lines, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).
(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity, to provide fast closure of the BOP components and to operate all critical functions;	The accumulator capacity must: (i) Close each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability to perform ROV functions within the required times outlined in API Standard 53 with ROV or flying leads. (iii) Have bottles located subsea for the autoshear and deadman (which may be shared between those two systems) to secure the wellbore. These bottles may also be utilized to perform the secondary control system functions (e.g., ROV or acoustic functions). (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;	You must have the ROV intervention capability to close each shear ram, ram locks, one pipe ram, and disconnect the LMRP under MASP conditions as defined for the operation. You must be capable of performing these functions in the response times outlined in API Standard 53 (as incorporated by reference in §250.198). The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.
	(ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.
	(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.
	(iv) Autoshear/deadman functions and an EDS mode must close, at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.
	(v) Your sequencing must allow a sufficient delay when closing your two shear rams in order to provide maximum sealing efficiency.
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under §250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions;	You must incorporate enable buttons, or a similar feature, on control panels to ensure two-handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels, such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system,	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent

including the prevention of accidental or unplanned disconnects of the system;	accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and (ii) A comprehensive knowledge of BOP hardware and control systems.
(12) Before removing the marine riser, displace the fluid in 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. You must follow the requirements of §250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.
(15) Install a gas bleed line with two valves for the annular preventer no later than April 30, 2018;	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, you must install the gas bleed line below the upper annular.
(16) Use a BOP system that has the following mechanisms and capabilities;	(i) No later than May 1, 2023, you must have the capability to position the entire pipe completely within the area of the shearing blade. This capability cannot be a separate ram BOP or annular preventer, but you may use those during a planned shear. (ii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

(b) If you suspend operations to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

(1) Submit a revised permit with a written statement from an independent third party documenting the repairs and certifying that the previous certification in §250.731(c) remains valid;

(2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with §250.737(d)(4), including deadman in accordance with §250.737(d)(12)(vi). If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of §250.737;

(3) Upon relatch of the LMRP, you must test according to the following:

(i) Pressure test riser connector/gasket in accordance with §250.737(b) and (c);

(ii) Pressure test choke and kill stabs at LMRP/BOP interface in accordance with §250.737(b) and (c);

(iii) Full function test of both pods and both control panels;

(iv) Verify acoustic pod communication (if equipped); and

(v) Deadman test with pressure test in accordance with §250.737(d)(12)(vi).

(4) Receive approval from the District Manager.

(c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21980, May 15, 2019]

Back to Top

§250.735 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 accumulator system (as specified in API Standard 53, incorporated by reference in §250.198). Your accumulator system must have the fluid volume capacity and appropriate pre-charge pressures in accordance with API Standard 53. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

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

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

(d) The choke line(s) installed above the bottom well-control ram;

(e) The kill line must be installed beneath at least one well-control ram, and may be installed below the bottom ram;

(f) A fill-up line above the uppermost BOP;

(g) Locking devices for all BOP sealing rams (*i.e.*, blind shear rams, pipe rams and variable bore rams), as follows:

(1) For subsea BOPs, hydraulic locking devices must be installed on all sealing rams;

(2) For surface BOPs:

(i) Remotely-operated locking devices must be installed on blind shear rams no later than April 29, 2019;

(ii) Manual or remotely-operated locking devices must be installed on pipe rams and variable bore rams; and

(h) A wellhead assembly with a RWP that exceeds the maximum anticipated wellhead pressure.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

Back to Top

§250.736 What are the requirements for choke manifolds, kelly-type valves inside BOPs, and drill string safety valves?

(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 RWP at least as great as the RWP 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 RWP at least as great as the RWP of the ram BOPs.

(d) You must use the following BOP equipment with a RWP and temperature of at least as great as the working pressure and temperature of the ram BOP during all operations:

(1) The applicable kelly-type valves as described in API Standard 53 (incorporated by reference in §250.198);

(2) On a top-drive system equipped with a remote-controlled valve, a strippable kelly-type valve must be installed below the remote-controlled valve;

(3) 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 pipe;

(4) 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 pipe;

(5) When running casing, a safety valve in the open position available on the rig floor to fit the casing string being run in the hole. For subsea BOPs, the safety valve must be available on the rig floor if the length of casing being run exceeds the water depth, which would result in the casing being across the BOP stack and the rig floor prior to crossing over to the drill pipe running string;

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

(7) A wrench to fit each manual valve. Each wrench must be readily accessible to the drilling crew.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

Back to Top

§250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

(a) *Pressure test frequency.* You must pressure test your BOP system:

(1) When installed;

(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) In lieu of meeting the schedule established in paragraph (a)(2) of this section, you may request that BSEE approve a 21-day BOP testing frequency. To obtain BSEE approval, you must submit a request to the appropriate BSEE Regional Supervisor, District Field Operations. Your request must demonstrate that you have developed a BOP health monitoring plan that includes certain system capabilities. As long as your plan is consistent with recognized engineering and industry practice, BSEE will approve your request if it includes the following:

(i) Condition monitoring tools, including continuous surveillance of sensor readings from the BOP control system, real-time condition analysis and displays, functional pressure signal analysis, historical sensor data;

(ii) Failure propagation analysis;

(iii) A failure tracking and resolution system that includes detailed failure reports and identification of recurring problems; and

(iv) Submission of quarterly reports of the data collected pursuant to paragraphs (a)(4)(i)(iii) to the BSEE Regional Supervisor, District Field Operations.

(5) The District Manager may require more frequent testing if conditions or your BOP performance warrant.

(b) *Pressure test procedures.* When you pressure test the BOP system, you must conduct a low-pressure test and a high-pressure test for each BOP component (excluding test rams and non-sealing shear rams). You must begin each test by conducting the low-pressure test then transition to the high-pressure test. Each individual pressure test must hold pressure long enough to demonstrate the tested component(s) holds the required pressure. The table in this paragraph (b) outlines your pressure test requirements.

You must conduct a . . .	**According to the following procedures . . .**
(1) Low-pressure test	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components	(i) The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation 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 permit. (ii) The blind shear ram (BSR) must be tested to: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent BSR pressure tests can be done to the casing/liner test pressure for the applicable hole section. (iii) The choke and kill side outlet valves must be tested to, except as provided in paragraph (d)(13) of this section: (A) MASP plus 500 psi for the hole section to which it is exposed; or (B) Full well MASP plus 500 psi on initial latch up and all subsequent pressure tests can be done to the casing/liner test pressure for the applicable hole section.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP	The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation 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 or APM.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours, or on a digital recorder. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, *i.e.,* cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

(d) *Additional test requirements.* You must meet the following additional BOP testing requirements:

You must . . .	**Additional requirements . . .**
(1) Follow the testing requirements of API Standard 53 (as incorporated in §250.198)	If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.
(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system	(i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing.
(3) Stump test a subsea BOP system before installation	(i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system.
	(ii) You must submit test procedures with your APD or APM for District Manager approval
	(iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing.
	(iv) You must verify closure of all ROV intervention functions on your subsea BOP stack during the stump test.
	(v) You must follow paragraphs (b) and (c) of this section. Pressure testing of each ram and annular component is only required once.
(4) Perform an initial subsea BOP test	(i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test.
	(ii) You must submit test procedures with your APD or APM for District Manager approval.
	(iii) You must pressure test well-control rams and annulars according to paragraphs (b) and (c) of this section.
	(iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing.
	(v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. You must confirm closure of the selected ram through the ROV hot stab with a 1,000 psi pressure test for 5 minutes.
(5) Alternate tests between control stations	(i) For two complete BOP control stations you must: (A) Designate a primary and secondary station; (B) Alternate testing between the primary and secondary control stations on a weekly basis; and (C) For a subsea BOP, develop an alternating testing schedule to ensure the primary and secondary control stations will function each pod.
	(ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests.
(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools	
(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests	

(10) Function test shear ram(s) BOPs every 14 days	If BSEE approves your request to utilize a 21-day BOP test frequency pursuant to §250.737(a)(4), you may function test shear ram(s) BOPs every 21 days in accordance with the terms of that approval.
(11) Actuate safety valves assembled with proper casing connections before running casing	
(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor	(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event. (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) Following the deadman system test on the seafloor you must document the final remaining pressure of the subsea accumulator system. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures. (vi) You must confirm closure of the BSR(s) with a 1,000 psi pressure test for 5 minutes. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.
(13) Pressure test the choke and kill side outlet valves	According to paragraph (b) of this section, except as follows: (i) Test the wellbore side of the choke and kill side outlet valves above the uppermost pipe ram to the approved annular test pressure. Choke and kill side outlet valves below the uppermost pipe ram must be tested to MASP plus 500 psi for the applicable hole section. (ii) For the 30 day BSR testing, test the wellbore side of the choke and kill side outlet valves between the upper most pipe ram and the upper most ram, to the casing/liner test pressure or annular test pressure, whichever is greater. (iii) For BOPs with only one choke and kill side outlet valve, you are only required to pressure test the choke and kill side outlet valves from the wellbore side.

(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the District Manager at least 72 hours in advance, to ensure that a BSEE representative will have access to the location to witness any testing.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21981, May 15, 2019]

Back to Top

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

The table in this section describes actions that you must take when certain situations occur with BOP systems.

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. You must report any problems or irregularities, including any leaks, on the daily report as required in §250.746.
(b) Need to repair, replace, or	(1) First place the well in a safe, controlled condition as approved by the District

reconfigure a surface BOP or subsea BOP system;	Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).
	(2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM.
	(3) Submit a revised permit with a written statement from an independent third party documenting the repairs, replacement, or reconfiguration and certifying that the previous certification under §250.731(c) remains valid.
	(4) You must receive approval from the District Manager prior to resuming operations.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;	Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered 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 pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Before running casing, perform a shell test to the permit approved test pressure of the BOP component above the casing ram/casing shear. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure;	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from an independent third party certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers and test(s).
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by:
	(1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation;
	(2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or
	(3) Some combination of paragraphs (l)(1) and (2) of this section.
(m) Plan to utilize any other circulating or ancillary equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from an independent third party on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from an independent third party that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the

rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by §250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

Back to Top

§250.739 What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions as designed. The BOP maintenance and inspections must meet or exceed any OEM recommendations, recognized engineering practices, and industry standards incorporated by reference into the regulations of this subpart, including API Standard 53 (incorporated by reference in §250.198). You must document how you met or exceeded the provisions of API Standard 53, maintain complete records to ensure the traceability of BOP stack equipment beginning at fabrication, and record the results of your BOP inspections and maintenance actions. You must make all records available to BSEE upon request.

(b) A major, detailed inspection of the well control system components (including but not limited to riser, BOP, LMRP, and control pods) must be performed every 5 years. This major inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. An independent third party is required to review the inspection results and must compile a detailed report of the inspection results, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This major inspection must be performed every 5 years from the following applicable dates, whichever is later:

(1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system;

(2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or

(3) The date of the last 5 year inspection for the component.

(c) You must visually inspect your surface BOP system on a daily basis. You must visually inspect your subsea BOP system, marine riser, and wellhead at least once every 3 days if weather and sea conditions permit. You may use cameras to inspect subsea equipment.

(d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, are trained in accordance with applicable training requirements in subpart S of this part, any applicable OEM criteria, recognized engineering practices, and industry standards incorporated by reference in this subpart.

(e) You must make all records available to BSEE upon request. You must ensure that the rig unit owner maintains the BOP maintenance, inspection, and repair records on the rig unit for 2 years from the date the records are created or for a longer period if directed by BSEE. You must ensure that all equipment schematics, maintenance, inspection, and repair records are located at an onshore location for the service life of the equipment.

[81 FR 26022, Apr. 29, 2016, as amended at 84 FR 21983, May 15, 2019]

Back to Top

Records and Reporting

Back to Top

§250.740 What records must I keep?

You must keep a daily report consisting of complete, legible, and accurate records for each well. You must keep records onsite while well operations continue. After completion of operations, you must keep all operation and other well records for the time periods shown in §250.741 at a location of your choice, except as required in §250.746. The records must contain complete information on all of the following:

(a) Well operations, all testing conducted, and any real-time monitoring data as required by §250.724;

(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 as appropriate to ensure compliance with the requirements of this section and to enable BSEE to determine that the well operations are consistent with conservation of natural resources and protection of safety and the environment on the OCS.

Back to Top

§250.741 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;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of 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 assign the lease and forward the records to the assignee.

Back to Top

§250.742 What well records am I required to submit?

You must submit to BSEE 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. Each Region will provide specific instructions for submitting well logs and surveys.

Back to Top

§250.743 What are the well activity reporting requirements?

(a) For operations in the BSEE Gulf of Mexico (GOM) OCS Region, you must submit Form BSEE-0133, Well Activity Report (WAR), to the District Manager on a weekly basis. The reporting week is defined as beginning on Sunday (12 a.m.) and ending on the following Saturday (11:59 p.m.). This reporting week corresponds to a week (Sunday through Saturday) on a standard calendar. Report any well operations that extend past the end of this weekly reporting period on the next weekly report. The reporting period for the weekly report is never longer than 7 days, but could be less than 7 days for the first reporting period and the last reporting period for a particular well operation. Submit each WAR and accompanying Form BSEE-0133S, Open Hole Data Report, to the BSEE GOM OCS Region no later than close of business on the Friday immediately after the closure of the reporting week. The District Manager may require more frequent submittal of the WAR on a case-by-case basis.

(b) For operations in the Pacific or Alaska OCS Regions, you must submit Form BSEE-0133, WAR, to the District Manager on a daily basis.

(c) The WAR must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well's as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information concerning well activities required by the District Manager. For casing cementing operations, indicate type of returns (*i.e.*, full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

Back to Top

§250.744 What are the end of operation reporting requirements?

(a) Within 30 days after completing operations, except routine operations as defined in §250.601, you must submit Form BSEE-0125, End of Operations Report (EOR), to the District Manager. The EOR must include: a listing, with top and bottom depths, of all hydrocarbon zones and other zones of porosity encountered with any cored intervals; details on any drill-stem and formation tests conducted; documentation of successful negative pressure testing on wells that use a subsea BOP stack or wells with mudline suspension systems; and an updated schematic of the full wellbore configuration. The schematic must be clearly labeled and show all applicable top and bottom depths, locations and sizes of all casings, cut casing or stubs, casing perforations, casing rupture discs (indicate if burst or collapse and rating), cemented intervals, cement plugs, mechanical plugs, perforated zones, completion equipment, production and isolation packers, alternate completions, tubing, landing nipples, subsurface safety devices, and any other information required by the District Manager regarding the end of well operations. The EOR must indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date of the well status designation. The well status date is subject to the following:

(1) For surface well operations and riserless subsea operations, the operations end date is subject to the discretion of the District Manager; and

(2) For subsea well operations, the operations end date is considered to be the date the BOP is disconnected from the wellhead unless otherwise specified by the District Manager.

(b) You must submit public information copies of Form BSEE-0125 according to §250.186(b).

Back to Top

§250.745 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 §250.740;

(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 sets forth 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.

Back to Top

§250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

You must record the time, date, and results of all casing and liner pressure tests. You must also record pressure tests, actuations, and inspections of the BOP system, system components, and marine riser in the daily report described in §250.740. In addition, you must:

(a) Record test pressures on pressure charts or digital recorders;

(b) Require your onsite lessee representative, designated rig or contractor representative, and pump operator to sign and date the pressure charts or digital recordings and daily reports as correct;

(c) Document on the daily report 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 on the daily report the control station and pod used during the test (identifying the pod does not apply to coiled tubing and snubbing units);

(e) Identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing must be documented in the WAR. If any problems that cannot be resolved promptly are observed during testing, operations must be suspended until the District Manager determines that you may continue; and

(f) Retain all records, including pressure charts, daily reports, and referenced documents pertaining to tests, actuations, and inspections at the rig unit for the duration of the operation. After completion of the operation, you must retain all the records listed in this section for a period of 2 years at the rig unit. You must also retain the records at the lessee's field office nearest the facility or at another location available to BSEE. You must make all the records available to BSEE upon request.

Back to Top

Coiled Tubing Operations

Back to Top

§250.750 What are the coiled tubing requirements?

(a) For coiled tubing operations, you must follow the applicable requirements of this subpart and 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

(i) Stripper or annular-type well control component	Stripper or annular-type well control component	Stripper or annular-type well control component.
(ii) Hydraulically-operated blind rams	Hydraulically-operated blind rams	Hydraulically-operated blind rams.
(iii) Hydraulically-operated shear rams	Hydraulically-operated shear rams	Hydraulically-operated shear rams.
(iv) Kill line inlet	Kill line inlet	Kill line inlet.
(v) Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams. Hydraulically-operated pipe rams.
(vi) Hydraulically-operated pipe rams	Hydraulically-operated pipe rams Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical	A flow tee or cross. 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 operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE-0124, 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.

(b) BSEE considers all coiled tubing operations to be non-routine.

[84 FR 21983, May 15, 2019]

Back to Top

§250.751 Coiled tubing testing requirements.

You must test the coiled tubing unit in accordance with §250.737(a), (b), (c), (d)(9), and (d)(10). 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. The test interval for coiled tubing operations must include a 10 minute high-pressure test for the coiled tubing string.

[84 FR 21984, May 15, 2019]

Back to Top

Snubbing Operations

Back to Top

§250.760 What are the snubbing requirements?

(a) For snubbing operations, you must follow the applicable requirements of this subpart and have the following minimum BOP-system components:

(1) One set of pipe rams hydraulically operated,

(2) Two sets of stripper-type pipe rams hydraulically operated with spacer spool,

(3) An inside BOP or a spring-loaded, back-pressure safety valve in the open position located on the rig floor, and

(4) An essentially full-opening, work-string safety valve in the open position must be maintained on the rig floor at all times and a wrench to fit the work-string safety valve must be readily available.

(5) Proper connections must be readily available for inserting valves in the work string.

(b) Test the snubbing unit in accordance with §250.737(a), (b), and (c).

[84 FR 21984, May 15, 2019]

Back to Top

Subpart H—Oil and Gas Production Safety Systems

Source: 81 FR 60918, Sept. 7, 2016, unless otherwise noted.

Back to Top

General Requirements

Back to Top

§250.800 General.

(a) You must design, install, use, maintain, and test production safety equipment in a manner to ensure the safety and protection of the human, marine, and coastal environments. For production safety systems operated in subfreezing climates, you must use equipment and procedures that account for floating ice, icing, and other extreme environmental conditions that may occur in the area. Before you commence production on a new production facility:

(1) BSEE must approve your production safety system application, as required in §250.842.

(2) You must request a preproduction inspection by notifying the District Manager at least 72 hours before you plan to commence initial production, as required under §250.880(a)(1).

(b) For all new production systems on fixed leg platforms, you must comply with API RP 14J (incorporated by reference as specified in §250.198);

(c) For all new floating production systems (FPSs) (e.g., column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); and spars), you must:

(1) Comply with API RP 14J;

(2) Meet the production riser standards of API RP 2RD (incorporated by reference as specified in §250.198), provided that you may not install single bore production risers from floating production facilities;

(3) Design all stationkeeping (*i.e.,* anchoring and mooring) systems for floating production facilities to meet the standards of API RP 2SK and API RP 2SM (both incorporated by reference as specified in §250.198); and

(4) Design stationkeeping (*i.e.,* anchoring and mooring) systems for floating facilities to meet the structural requirements of §§250.900 through 250.921.

(d) If there are any conflicts between the documents incorporated by reference and the requirements of this subpart, you must follow the requirements of this subpart.

(e) You may use alternate procedures or equipment during operations after receiving approval from the District Manager. You must present your proposed alternate procedures or equipment as required by §250.141.

(f) You may apply for a departure from the operating requirements of this subpart as provided by §250.142. Your written request must include a justification showing why the departure is necessary and appropriate.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

Back to Top

§250.801 Safety and pollution prevention equipment (SPPE) certification.

(a) *SPPE equipment.* You must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. BSEE considers the following equipment to be types of SPPE:

(1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow;

(2) Boarding shutdown valves (BSDV) and their actuators. For subsea wells, the BSDV is the surface equivalent

of an SSV on a surface well;

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

(4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples; and

(5) Gas lift shutdown valves (GLSDV) and their actuators associated with subsea systems.

(b) *Certification of SPPE.* SPPE that is manufactured and marked pursuant to ANSI/API Spec. Q1 (incorporated by reference as specified in §250.198), is considered as certified SPPE under this part. All other SPPE is considered as not certified, unless approved in accordance with paragraph (c) of this section.

(c) *Accepting SPPE manufactured under other quality assurance programs.* BSEE may exercise its discretion to accept SPPE manufactured under a quality assurance program other than ANSI/API Spec. Q1, provided that the alternative quality assurance program is verified as equivalent to API Spec. Q1 by an appropriately qualified entity and that the operator submits a request to BSEE containing relevant information about the alternative program and receives BSEE approval. In addition, an operator may request that BSEE accept SPPE that is marked with a third-party certification mark other than the API monogram. All requests under this paragraph should be submitted to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; VAE-ORP; 45600 Woodland Road, Sterling, VA 20166.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

Back to Top

§250.802 Requirements for SPPE.

(a) All SSVs, BSDVs, USVs, and GLSDVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference in §250.198).

(b) All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in §250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.

(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, SSSVs, USVs, GLSDVs, and their actuators, include, but are not limited to, the following:

(1) You must ensure that each device is designed to function in the conditions to which it may be exposed; including temperature, pressure, flow rates, and environmental conditions.

(i) The device design must be tested by an independent test agency according to the test requirements in the appropriate standard for that device (API Spec. 6AV1 or ANSI/API Spec. 14A), as identified in paragraphs (a) and (b) of this section.

(ii) You must maintain a description of the process you used to ensure the device is designed to function as required in paragraphs (a) and (c)(1) of this section and provide that description to BSEE upon request.

(iii) If you remove any SPPE from service and install the device at a different location, you must have a qualified third party review and certify that each device will function as designed under the conditions to which it may be exposed.

(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.

(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.

(4) You must have requalification testing performed following manufacture design changes.

(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.

(6) You must follow specified installation, testing, and repair protocols.

(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.

(d) You must install and use SPPE according to the following table.

If . . .	Then . . .
(1) You need to install any SPPE	You must install SPPE that conforms to §250.801.
(2) A non-certified SPPE is already in service	It may remain in service.
(3) A non-certified SPPE requires offsite repair, re-manufacturing, or any hot work such as welding	You must replace it with SPPE that conforms to §250.801.

(e) You must retain all documentation related to the manufacture, installation, testing, repair, redress, and performance of the SPPE until 1 year after the date of decommissioning of the equipment.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49256, Sept. 28, 2018]

Back to Top

§250.803 What SPPE failure reporting procedures must I follow?

(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A for SSVs, BSDVs, GLSDVs and USVs. You must follow the failure reporting requirements contained in section 7.10 of ANSI/API Spec. 14A and Annex F of ANSI/API RP 14B for SSSVs (all incorporated by reference in §250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.

(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.

(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.

(d) BSEE may designate a third party to receive the data required by paragraphs (a) through (c) of this section on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.

[83 FR 49256, Sept. 28, 2018]

Back to Top

§250.804 Additional requirements for subsurface safety valves (SSSVs) 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) or Application for Permit to Modify (APM), and 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 analyses;

(2) A discussion of the SSSVs' and related equipment's design validation and functional testing processes and procedures used; and

(3) An explanation of why the analyses, processes, 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 psia 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 psia 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.

Back to Top

§250.805 Hydrogen sulfide.

(a) 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, you must conduct production operations in accordance with that section and other relevant requirements of this subpart.

(b) You must receive approval through the DWOP process (§§250.286 through 250.295) for production operations in HPHT environments known to contain H_2S or in HPHT environments where the presence of H_2S is unknown.

Back to Top

§§250.806-250.809 [Reserved]2

Back to Top

Surface and Subsurface Safety Systems—Dry Trees

Back to Top

§250.810 Dry tree subsurface safety devices—general.

For wells using dry trees or for which you intend to install dry trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after you submit a request containing a justification, the District Manager determines the well to be incapable of natural flow. You must install flow couplings above and below the subsurface safety devices. These subsurface safety devices include the following devices and any associated safety valve lock and landing nipple:

(a) An SSSV, including either:

(1) A surface-controlled SSSV; or

(2) A subsurface-controlled SSSV.

(b) An injection valve.

(c) A tubing plug.

(d) A tubing/annular subsurface safety device.

Back to Top

§250.811 Specifications for SSSVs—dry trees.

All surface-controlled and subsurface-controlled SSSVs, safety valve locks, and landing nipples installed in the OCS must conform to the requirements specified in §§250.801 through 250.803.

Back to Top

§250.812 Surface-controlled SSSVs—dry trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§250.813, 250.815, and 250.816.

(a) The surface controls must be located on the site or at a BSEE-approved remote location. You may request District Manager approval to situate the surface controls at a remote location.

(b) You must equip dry tree wells not previously equipped with a surface-controlled SSSV, and dry tree wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV, with a surface-controlled SSSV when the tubing is first removed and reinstalled.

Back to Top

§250.813 Subsurface-controlled SSSVs.

You may submit an APM or a request to the District Manager for approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, if the subsurface-controlled SSSV is installed in a well equipped with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.

Back to Top

§250.814 Design, installation, and operation of SSSVs—dry trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while the SSSV is inoperable, except when flowing the well is necessary for a particular operation such as cutting paraffin or performing other routine operations as defined in §250.601.

(c) Until the SSSV is installed, the well must be attended in the immediate vicinity so that any necessary emergency actions can be taken while the well is open to flow. During testing and inspection procedures, the well must not be left unattended while open to production unless you have installed a properly operating SSSV in the well.

(d) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with ANSI/API RP 14B (incorporated by reference in §250.198). For additional SSSV testing requirements, refer to §250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§250.815 Subsurface safety devices in shut-in wells—dry trees.

(a) You must equip all new dry tree completions (perforated but not placed on production) and completions that are shut-in for a period of 6 months with one of the following:

(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.

(b) When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

Back to Top

§250.816 Subsurface safety devices in injection wells—dry trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

Back to Top

§250.817 Temporary removal of subsurface safety devices for routine operations.

(a) You may remove a wireline- or pumpdown-retrievable subsurface safety device without further authorization or notice, for a routine operation that does not require BSEE approval of a Form BSEE-0124, Application for Permit to Modify (APM). For a list of these routine operations, see §250.601. The removal period must not exceed 15 days.

(b) Prior to removal, you must identify the well by placing a sign on the wellhead stating that the subsurface safety device was removed. You must note the removal of the subsurface safety device in the records required by §250.890. If the master valve is open, you must ensure that a trained person (see §250.891) is in the immediate vicinity to attend the well and take any necessary emergency actions.

(c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to 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 by a support vessel, or a pump-through plug must be installed in the tubing at least 100 feet below the mudline and the master valve must be closed, unless otherwise approved by the appropriate District Manager.

(d) You must not allow the well to flow while the subsurface safety device is removed, except when it is necessary for the particular operation for which the SSSV is removed. The provisions of this paragraph are not applicable to the testing and inspection procedures specified in §250.880.

Back to Top

§250.818 Additional safety equipment—dry trees.

(a) You must equip all tubing installations that have a wireline- or pumpdown-retrievable subsurface safety device with a landing nipple, with flow couplings or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform emergency shutdown system (ESD).

(c) 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 SSSVs must close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

Back to Top

§250.819 Specification for surface safety valves (SSVs).

All wellhead SSVs and their actuators must conform to the requirements specified in §§250.801 through 250.803.

Back to Top

§250.820 Use of SSVs.

You must install, maintain, inspect, repair, and test all SSVs in accordance with API STD 6AV2 (incorporated by reference in §250.198). If any SSV does not operate properly, or if any gas and/or liquid fluid flow is observed during the leakage test as described in §250.880, then you must shut-in all sources to the SSV and repair or replace the valve before resuming production.

[83 FR 49257, Sept. 28, 2018]

Back to Top

§250.821 Emergency action and safety system shutdown—dry trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.,* an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must:

(1) Properly install a subsurface safety device on any well that is not yet equipped with a subsurface safety device and that is capable of natural flow, as soon as possible, with due consideration being given to personnel safety.

(2) You must shut-in (by closing the SSV and the surface-controlled SSSV) the following types of wells:

(i) All oil wells, and

(ii) All gas wells requiring compression.

(b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any alternative design-delayed closure time of greater than 2 minutes based on the mechanical/production characteristics of the individual well.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§§250.822-250.824 [Reserved]

Back to Top

Subsea and Subsurface Safety Systems—Subsea Trees

Back to Top

§250.825 Subsea tree subsurface safety devices—general.

(a) For wells using subsea (wet) trees or for which you intend to install subsea trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency. You must also install flow couplings above and below the subsurface safety devices. For instances where the well at issue is incapable of natural flow, you may seek District Manager approval for using alternative procedures or equipment, if you propose to use a subsea safety system that is not capable of shutting off the flow from the well in the event of an emergency. Subsurface safety devices include the following and any associated safety valve lock and landing nipple:

(1) A surface-controlled SSSV;

(2) An injection valve;

(3) A tubing plug; and

(4) A tubing/annular subsurface safety device.

(b) After installing the subsea tree, but before the rig or installation vessel leaves the area, you must test all valves and sensors to ensure that they are operating as designed and meet all the conditions specified in this subpart.

Back to Top

§250.826 Specifications for SSSVs—subsea trees.

All SSSVs, safety valve locks, and landing nipples installed on the OCS must conform to the requirements specified in §§250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§250.286 through 250.295.

Back to Top

§250.827 Surface-controlled SSSVs—subsea trees.

You must equip all tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow with a surface-controlled SSSV, except as specified in §§250.829 and 250.830. The surface controls must be located on the host facility.

Back to Top

§250.828 Design, installation, and operation of SSSVs—subsea trees.

You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.

(a) You must install the SSSV at a depth at least 100 feet below the mudline. When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, or paraffin problems, the District Manager may approve an alternate setting depth on a case-by-case basis.

(b) The well must not be open to flow while an SSSV is inoperable, unless specifically approved by the District Manager in an APM.

(c) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and ANSI/API RP 14B (incorporated by reference in §250.198). For additional SSSV testing requirements, refer to §250.880.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§250.829 Subsurface safety devices in shut-in wells—subsea trees.

(a) You must equip all new subsea tree completions (perforated but not placed on production) and completions shut-in for a period of 6 months with one of the following:

(1) A pump-through-type tubing plug;

(2) An injection valve capable of preventing backflow; or

(3) A surface-controlled SSSV, provided the surface control has been rendered inoperative. For purposes of this section, a surface-controlled SSSV is considered inoperative if, for a direct hydraulic control system, you have bled the hydraulics from the control line and have isolated it from the hydraulic control pressure. If your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, a surface-controlled SSSV is considered inoperative if you perform the following:

(i) Disable the control function of the surface-controlled SSSV within the logic of the programmable logic controller which controls the subsea well;

(ii) Place a pressure alarm high on the control line to the surface-controlled SSSV of the subsea well; and

(iii) Close the USV and at least one other tree valve on the subsea well.

(b) When warranted by conditions, such as unstable bottom conditions, permafrost, hydrate formation, and paraffin problems, the District Manager must approve the setting depth of the subsurface safety device for a shut-in well on a case-by-case basis.

Back to Top

§250.830 Subsurface safety devices in injection wells—subsea trees.

You must install a surface-controlled SSSV or an injection valve capable of preventing backflow in all injection wells. This requirement is not applicable if the District Manager determines that the well is incapable of natural flow. You must verify the no-flow condition of the well annually.

Back to Top

§250.831 Alteration or disconnection of subsea pipeline or umbilical.

If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well would affect your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate District Office at least 48 hours in advance and submit a repair or replacement plan to conduct the required monitoring and testing. You must not alter or disconnect until the repair or replacement plan is approved.

Back to Top

§250.832 Additional safety equipment—subsea trees.

(a) You must equip all tubing installations that have a wireline- or pump down-retrievable subsurface safety device installed after May 31, 1988, with a landing nipple, with flow couplings, or other protective equipment above and below it to provide for the setting of the device.

(b) The control system for all surface-controlled SSSVs must be an integral part of the platform ESD.

(c) 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.

Back to Top

§250.833 Specification for underwater safety valves (USVs).

All USVs, including those designated as primary or secondary, and any alternate isolation valve (AIV) that acts as a USV, if applicable, and their actuators, must conform to the requirements specified in §§250.801 through 250.803. A production master or wing valve may qualify as a USV under ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference in §250.198).

(a) Primary USV (USV1). You must install and designate one USV on a subsea tree as the USV1. The USV1 must be located upstream of the choke valve. As provided in paragraph (b) of this section, you must inform BSEE if the primary USV designation changes.

(b) Secondary USV (USV2). You may equip your tree with two or more valves qualified to be designated as a USV, one of which may be designated as the USV2. If the USV1 fails to operate properly or exhibits a leakage rate greater than allowed in §250.880, you must notify the appropriate District Office and designate the USV2 or another qualified valve (e.g., an AIV) that meets all the requirements of this subpart for USVs as the USV1. The USV2 must be located upstream of the choke.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§250.834 Use of USVs.

You must install, maintain, inspect, repair, and test any valve designated as the primary USV in accordance with this subpart, your DWOP (as specified in §§250.286 through 250.295), and API STD 6AV2 (incorporated by reference in §250.198). For additional USV testing requirements, refer to §250.880.

[83 FR 49257, Sept. 28, 2018]

Back to Top

§250.835 Specification for all boarding shutdown valves (BSDVs) associated with subsea systems.

You must install a BSDV on the pipeline boarding riser. All new BSDVs and any BSDVs removed from service for remanufacturing or repair and their actuators installed on the OCS must meet the requirements specified in §§250.801 through 250.803. In addition, you must:

(a) Ensure that the internal design pressure(s) of the pipeline(s), riser(s), and BSDV(s) is fully rated for the maximum pressure of any input source and complies with the design requirements set forth in subpart J, unless BSEE approves an alternate design.

(b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application.

(c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (*i.e.,* within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical).

(d) Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV.

Back to Top

§250.836 Use of BSDVs.

You must install, inspect, maintain, repair, and test all new BSDVs, as well as all BSDVs that you remove from service for remanufacturing or repair, in accordance with API STD 6AV2 (incorporated by reference in §250.198) for SSVs. If any BSDV does not operate properly or if any gas fluid and/or liquid fluid flow is observed during the leakage test, as described in §250.880, you must shut-in all sources to the BSDV and immediately repair or replace the valve.

[83 FR 49257, Sept. 28, 2018]

Back to Top

§250.837 Emergency action and safety system shutdown—subsea trees.

(a) If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.,* an impending National Weather Service-named tropical storm or hurricane, ice events, or post-earthquake), you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, GLSDV, and surface-controlled SSSV.

(b) When operating a mobile offshore drilling unit (MODU) or other type of workover or intervention vessel in an area with subsea infrastructure, you must:

(1) Suspend production from all wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline; or

(2) Establish direct, real-time communications between the MODU or other type of workover or intervention vessel and the production facility control room and develop a dropped objects plan, as required in §250.714. If an object is dropped, you must immediately secure the well directly under the MODU or other type of workover or intervention vessel while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the production facility and the MODU or other type of workover or intervention vessel. If communication is lost between the MODU or other type of workover or intervention vessel and the platform for 20 or more minutes, you must shut-in all wells that could be affected by a dropped object.

(c) In the event of an emergency, you must operate your production system according to the valve closure times in the applicable tables in §§250.838 and 250.839 for the following conditions:

(1) *Process upset.* In the event an upset in the production process train occurs downstream of the BSDV, you must close the BSDV in accordance with the applicable tables in §§250.838 and 250.839. You may reopen the BSDV to blow down the pipeline to prevent hydrates, provided you have secured the well(s) and ensured adequate protection.

(2) *Pipeline pressure safety high and low (PSHL) sensor.* In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system, by closing the BSDVs, USVs, and surface-controlled SSSVs in accordance with the applicable tables in §§250.838 and 250.839. You must obtain approval from the appropriate District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate District Manager.

(3) *ESD/TSE (platform).* In the event of an ESD activation that is initiated because of a platform ESD or platform TSE not associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§250.838 and 250.839.

(4) *Subsea ESD (platform) or BSDV TSE.* In the event of an emergency shutdown activation that is initiated by the host platform due to an abnormal condition subsea, or a TSE associated with the BSDV, you must close the BSDV, USV, and surface-controlled SSSV in accordance with the applicable tables in §§250.838 and 250.839.

(5) *Subsea ESD (MODU).* In the event of an ESD activation that is initiated by a dropped object from a MODU or other type of workover or intervention vessel, you must secure all wells in the proximity of the MODU or other type of workover or intervention vessel by closing the USVs and surface-controlled SSSVs in accordance with the applicable tables in §§250.838 and 250.839. You must notify the appropriate District Manager before resuming production.

(d) Following an ESD or fire, you must bleed your low pressure (LP) and high pressure (HP) hydraulic systems in accordance with the applicable tables in §§250.838 and 250.839 to ensure that the valves are locked out of service and cannot be reopened inadvertently.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§250.838 What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?

(a) If you have an electro-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in paragraphs (b) and (d) of this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP as long as communication is maintained with the platform or with the MODU or other type of workover vessel:

Valve Closure Timing, Electro-Hydraulic Control System

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset	Close within 45 seconds after sensor activation	[no requirements]			[no requirements]	[no requirements]	[no requirements].
(2) Pipeline PSHL	Close within 45 seconds after sensor activation	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated USV1 within 20 minutes after sensor activation.			Close within 60 minutes after sensor activation. If you use a 60-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 24 hours total	[no requirements]	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform)	Close within 45 seconds after ESD or sensor activation	Close within 5 minutes after ESD or sensor activation. If you use a 5-minute resettable timer, you may continue to reset the time for closure up to a maximum of 20 minutes total	Close within 20 minutes after ESD or sensor activation.		Close within 20 minutes after ESD or sensor activation. If you use a 20-minute manual resettable timer, you may continue to reset the time for closure up to a maximum of 60 minutes total	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation. If you use a 60-minute manual resettable timer you must initiate unrestricted bleed within 24 hours.
(4) Subsea ESD (Platform) or BSDV TSE	Close within 45 seconds after ESD or sensor activation	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation			Close within 10 minutes after ESD or sensor activation	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel, Dropped object)	[no requirements]	Initiate valve closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately	Initiate unrestricted bleed within 10 minutes after ESD activation.

(c) If you have an electro-hydraulic control system and experience a loss of communications (EH Loss of Comms), you must comply with the following:

(1) If you can meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office within 12 hours of detecting the loss of communication.

(2) If you cannot meet the EH Loss of Comms valve closure timing conditions specified in the table in paragraph (d) of this section, you must notify the appropriate District Office immediately after detecting the loss of communication. You must shut-in production by initiating a bleed of the low pressure (LP) hydraulic system or the high pressure (HP) hydraulic system within 120 minutes after loss of communication. You must bleed the other hydraulic system within 180 minutes after loss of communication.

(3) You must obtain approval from the appropriate District Manager before continuing to produce after loss of communication when you cannot meet the EH Loss of Comms valve closure times specified in the table in paragraph (d) of this section. In your request, include an alternate valve closure timing table that your system is able to achieve. The appropriate District Manager may also approve an alternate hydraulic bleed schedule to allow for hydrate mitigation and orderly shut-in.

(d) If you experience a loss of communications, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

Valve Closure Timing, Electro-Hydraulic Control System With Loss of Communication

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset	Close within 45 seconds after sensor activation	[no requirements]			[no requirements]	[no requirements]	[no requirements].
(2) Pipeline PSHL	Close within 45 seconds after sensor activation	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after sensor activation).			Initiate closure when HP hydraulic system is bled (close within 24 hours after sensor activation)	Initiate unrestricted bleed immediately, concurrent with sensor activation	Initiate unrestricted bleed within 24 hours after sensor activation.
(3) ESD/TSE (Platform)	Close within 45 seconds after ESD or sensor activation	Initiate closure when LP hydraulic system is bled (close valves within 20 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 60 minutes after ESD or sensor activation)	Initiate unrestricted bleed concurrent with BSDV closure (bleed within 20 minutes after ESD or sensor activation)	Initiate unrestricted bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE	Close within 45 seconds after ESD or sensor activation	Initiate closure when LP hydraulic system is bled (close valves within 5 minutes after ESD or sensor activation).			Initiate closure when HP hydraulic system is bled (close within 20 minutes after ESD or sensor activation)	Initiate unrestricted bleed immediately	Initiate unrestricted bleed immediately, allowing for surface-controlled SSSV closure.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object	[no requirements]	Initiate closure immediately. You may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV if desired.				Initiate unrestricted bleed immediately	Initiate unrestricted bleed immediately.

Back to Top

§250.839 What are the maximum allowable valve closure times and hydraulic bleeding requirements for a direct-hydraulic control system?

(a) If you have a direct-hydraulic control system, you must:

(1) Design the subsea control system to meet the valve closure times listed in this section or your approved DWOP; and

(2) Verify the valve closure times upon installation. The District Manager may require you to verify the closure time of the USV(s) through visual authentication by diver or ROV.

(b) You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:

Valve Closure Timing, Direct-Hydraulic Control System

If you have the following. . .	Your pipeline BSDV must. . .	Your USV1 must. . .	Your USV2 must. . .	Your alternate isolation valve must. . .	Your surface-controlled SSSV must. . .	Your LP hydraulic system must. . .	Your HP hydraulic system must. . .
(1) Process upset	Close within 45 seconds after sensor activation	[no requirements]			[no requirements]	[no requirements]	[no requirements]
(2) Flowline PSHL	Close within 45 seconds after sensor	Close one or more valves within 2 minutes and 45 seconds after sensor activation. Close the designated			Close within 24 hours after sensor	Complete bleed of USV1, USV2, and the AIV within 20	Complete bleed within 24 hours

	activation	USV1 within 20 minutes after sensor activation.	activation	minutes after sensor activation	after sensor activation.
(3) ESD/TSE (Platform)	Close within 45 seconds after ESD or sensor activation	Close all valves within 20 minutes after ESD or sensor activation.	Close within 60 minutes after ESD or sensor activation	Complete bleed of USV1, USV2, and the AIV within 20 minutes after ESD or sensor activation	Complete bleed within 60 minutes after ESD or sensor activation.
(4) Subsea ESD (Platform) or BSDV TSE	Close within 45 seconds after ESD or sensor activation	Close one or more valves within 2 minutes and 45 seconds after ESD or sensor activation. Close all tree valves within 10 minutes after ESD or sensor activation.	Close within 10 minutes after ESD or sensor activation	Complete bleed of USV1, USV2, and the AIV within 10 minutes after ESD or sensor activation	Complete bleed within 10 minutes after ESD or sensor activation.
(5) Subsea ESD (MODU or other type of workover vessel), Dropped object	[no requirements]	Initiate closure immediately. If desired, you may allow for closure of the tree valves immediately prior to closure of the surface-controlled SSSV.		Initiate unrestricted bleed immediately	Initiate unrestricted bleed immediately.

Back to Top

PRODUCTION SAFETY SYSTEMS

Back to Top

§250.840 Design, installation, and maintenance—general.

You must design, install, and maintain all production facilities and equipment including, but not limited to, separators, treaters, pumps, heat exchangers, fired components, wellhead injection lines, compressors, headers, and flowlines in a manner that is efficient, safe, and protects the environment.

Back to Top

§250.841 Platforms.

(a) 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 the provisions of 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 in API RP 14C to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are contained in §250.1004.

(b) You must design, install, inspect, repair, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E and API 570 (both incorporated by reference as specified in §250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days.

(c) If you plan to make a modification to any production safety system that also involves a major modification to the platform structure, you must follow the requirements in §250.900(b)(2). A major modification to a platform structure is defined in §250.900(b)(2).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49257, Sept. 28, 2018]

Back to Top

§250.842 Approval of safety systems design and installation features.

(a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager. The District Manager must approve your production safety system application before you commence production through or otherwise use the new or modified system. The application must include the design documentation prescribed as follows:

You must submit:	Details and/or additional requirements:
(1) Safety analysis flow diagram (API RP 14C, Annex B) and Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, section 6.3.3) (incorporated by reference in §250.198)	Your safety analysis flow diagram must show the following: (i) Well shut-in tubing pressure; (ii) Pressure relieving device set points; (iii) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors, and metering devices;
	(iv) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps;

	(v) Size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and API RP 505 (both incorporated by reference in §250.198); and
	(vi) Piping sizes and maximum allowable working pressures as determined in accordance with API RP 14E (incorporated by reference in §250.198), including the locations of piping specification breaks.
(2) Electrical one-line diagram;	Showing elements including generators, circuit breakers, transformers, bus bars, conductors, automatic transfer switches, uninterruptable power supply (UPS) and associated battery banks, dynamic (motor) loads, and static loads (*e.g.,* electrostatic treater grid, lighting panels). You must also include a functional legend.
(3) Area classification diagram;	A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference in §250.198). The plan must contain: (i) All major production equipment, wells, and other significant hydrocarbon and class 1 flammable sources, and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and (ii) The location of generators and any buildings (e.g., control rooms and motor control center (MCC) buildings) or major structures on the platform.
(4) A piping and instrumentation diagram, for new facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.
(5) 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.

(b) You must develop and maintain the following design documents and make them available to BSEE upon request:

Diagram:	**Details and/or additional requirements:**
(1) Additional electrical system information;	(i) Cable tray/conduit routing plan that identifies the primary wiring method (e.g., type cable, cable schedule, conduit, wire); and
	(ii) Panel board/junction box location plan, if this information is not shown on the area classification diagram required in paragraph (a)(3) of this section.
(2) Schematics of the fire and gas-detection systems;	Showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; and the method used for detection.
(3) Revised piping and instrumentation diagram for existing facilities;	A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.

(c) In the production safety system application, you must also certify the following:

(1) That all electrical systems were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference in §250.198);

(2) That the design documents for the mechanical and electrical systems that you are required to submit under paragraph (a) of this section are sealed by a licensed professional engineer. For modified systems, only the modifications are required to be sealed by a licensed professional engineer(s). The professional engineer must be licensed in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and

(3) That a hazards analysis was performed in accordance with §250.1911 and API RP 14J (incorporated by reference in §250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the facility.

(d) Within 90 days after placing new or modified production safety systems in service, you must submit to the District Manager the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1), (2), and (3) of this section. You must certify in an accompanying letter that the as-built design documents have been reviewed for compliance with applicable regulations and accurately represent the new or modified system as installed. The drawings must be clearly marked “as-built.”

(e) You must maintain approved and supporting design documents required under paragraphs (a) and (b) of this section at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. These documents must be made available to BSEE upon request and must be retained for the life of the facility. All approved designs are subject to field verifications.

[84 FR 24705, May 29, 2019]

Back to Top

§§250.843-250.849 [Reserved]

Back to Top

Additional Production System Requirements

Back to Top

§250.850 Production system requirements—general.

You must comply with the production safety system requirements in §§250.851 through 250.872, in addition to the practices contained in API RP 14C (incorporated by reference as specified in §250.198).

Back to Top

§250.851 Pressure vessels (including heat exchangers) and fired vessels.

(a) Pressure vessels (including heat exchangers) and fired vessels supporting production operations must meet the requirements in the following table:

Item name	Applicable codes and requirements
(1) Pressure and fired vessels	(i) Must be designed, fabricated, and code stamped according to applicable provisions of sections I, IV, and VIII of the ANSI/ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in §250.198). (ii) Must be repaired, maintained, and inspected in accordance with API 510 (incorporated by reference as specified in §250.198).
(2) Existing uncoded pressure and fired vessels:	Must be justified and approval obtained from the District Manager for their continued use.
(i) With an operating pressure greater than 15 psig; and	
(ii) That are not code stamped in accordance with the ASME Boiler and Pressure Vessel Code	
(3) Pressure relief valves	(i) Must be designed and installed according to applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code (incorporated by reference as specified in §250.198). (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only). (iii) Vents must be positioned in such a way as to prevent fluid from striking personnel or ignition sources.
(4) Steam generators operating at less than 15 psig	Must 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.
(5) Steam generators operating at 15 psig or greater	(i) Must 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. (ii) Must be equipped with a water-feeding device that will automatically control the water level except when closed loop systems are used for steam generation.

(b) *Operating pressure ranges.* You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time that the normalized system pressure changes by 50 psig or 5 percent. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the pressure recording information you used to determine current operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements

(1) High pressure shut-in sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the vessel	Must 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.
(2) Low pressure shut-in sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest pressure in the operating range	You must receive specific approval from the District Manager for activation limits on pressure vessels that have a pressure safety low (PSL) sensor set less than 5 psi.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24706, May 29, 2019]

Back to Top

§250.852 Flowlines/Headers.

(a) You must:

(1) Equip flowlines from wells with both PSH and PSL sensors. You must locate these sensors in accordance with section A.1 of API RP 14C (incorporated by reference as specified in §250.198).

(2) Use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long.

(3) Maintain the most recent pressure recording information you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.

(b) Flowline shut-in sensors must meet the requirements in the following table (initial set points for pressure sensors must be set using gauge readings and engineering design):

Type of flowline sensor	Settings
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the flowline. In all cases, the PSH must be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to ensure actuation of the SSV. Do not set the PSH sensor above the maximum allowable working pressure of the flowline.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the flowline in which it is installed.

(c) If a well flows directly to a pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) must 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:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. You must design the platform flare scrubber to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of hydrocarbons that may be relieved to the vessel; or

(2) Two SSVs with independent PSH sensors connected to separate relays and sensing points and installed with adequate volume upstream of any block valve to allow sufficient time for the SSVs to close before exceeding the maximum allowable working pressure. Each independent PSH sensor must close both SSVs along with any associated flowline PSL sensor. If the maximum shut-in pressure of a dry tree satellite well(s) is greater than $1\frac{1}{2}$ times the maximum allowable pressure of the pipeline, a pressure safety valve (PSV) of sufficient size and relief capacity to protect against any SSV leakage or fluid hammer effect may be required by the District Manager. The PSV must be installed upstream of the host platform boarding valve and vent into the platform flare scrubber or some other location approved by the District Manager.

(d) If a well flows directly to the pipeline from a header without prior separation, the header, the header inlet valves, and pipeline isolation valve must have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the header is protected by the safety devices as outlined in paragraph (c) of this section.

(e) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(1) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of ANSI/API Spec. 17J (incorporated by reference in §250.198);

(2) Determine that the unbonded flexible pipe is suitable for its intended purpose;

(3) Submit to the District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(4) Submit to the 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 ANSI/API Spec. 17J (incorporated by reference in §250.198).

(f) Automatic pressure or flow regulating choking devices must not prevent the normal functionality of the process safety system that includes, but is not limited to, the flowline pressure safety devices and the SSV.

(g) You may install a single flow safety valve (FSV) on the platform to protect multiple subsea pipelines or wells that tie into a single pipeline riser provided that you install an FSV for each riser on the platform and test it in accordance with the criteria prescribed in §250.880(c)(2)(v).

(h) You may install a single PSHL sensor on the platform to protect multiple subsea pipelines that tie into a single pipeline riser provided that you install a PSHL sensor for each riser on the platform and locate it upstream of the BSDV.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

Back to Top

§250.853 Safety sensors.

You must ensure that:

(a) All shutdown devices, valves, and pressure sensors function in a manual reset mode;

(b) Sensors with integral automatic reset are equipped with an appropriate device to override the automatic reset mode;

(c) All pressure sensors are equipped to permit testing with an external pressure source; and

(d) All level sensors are equipped to permit testing through an external bridle on all new vessel installations where possible, depending on the type of vessel for which the level sensor is used.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

Back to Top

§250.854 Floating production units equipped with turrets and turret-mounted systems.

(a) For floating production units equipped with an auto slew system, you must integrate the auto slew control system with your process safety system allowing for automatic shut-in of the production process, including the sources (subsea wells, subsea pumps, *etc.*) and releasing of the buoy. Your safety system must immediately initiate a process system shut-in according to §§250.838 and 250.839 and release the buoy to prevent hydrocarbon discharge and damage to the subsea infrastructure when the following are encountered:

(1) Your buoy is clamped,

(2) Your auto slew mode is activated, and

(3) You encounter a ship heading/position failure or an exceedance of the rotational tolerances of the clamped buoy.

(b) For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, your surface safety system must immediately initiate a process system shut-in according to §§250.838 and 250.839.

Back to Top

§250.855 Emergency shutdown (ESD) system.

The ESD system 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:

(a) The manually operated ESD valve(s) must be quick-opening and non-restricted to enable the rapid actuation of the shutdown system. Electronic ESD stations must be wired as de-energize to trip circuits or as supervised circuits. Because of the key role of the ESD system in the platform safety system, all ESD components must be of high quality and corrosion resistant and stations must be uniquely identified. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve or electric switch. This breakable loop is not required to be physically located on the boat landing, but must be accessible from a vessel adjacent to or attached to the facility.

(b) You must maintain a schematic of the ESD that indicates the control functions of all safety devices for the platforms on the platform, at your field office nearest the OCS facility, or at another location conveniently available to the District Manager, for the life of the facility.

Back to Top

§250.856 Engines.

(a) *Engine exhaust.* You must equip all engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2 (incorporated by reference as specified in §250.198). You must equip exhaust piping from diesel engines with spark arresters.

(b) *Diesel engine air intake.* You must equip diesel engine air intakes with a device to shut down the diesel engine in the event of runaway (*i.e.,* overspeed). You must equip diesel engines that are continuously attended with either remotely operated manual or automatic shutdown devices. You must equip diesel engines that are not continuously attended with automatic shutdown devices. The following diesel engines do not require a shutdown device: Engines for fire water pumps; engines on emergency generators; engines that power BOP accumulator systems; engines that power air supply for confined entry personnel; temporary equipment on non-producing platforms; booster engines whose purpose is to start larger engines; and engines that power portable single cylinder rig washers.

Back to Top

§250.857 Glycol dehydration units.

(a) You must install a pressure relief system or an adequate vent on the glycol regenerator (reboiler) to prevent over pressurization. The discharge of the relief valve must be vented in a nonhazardous manner.

(b) You must install the FSV on the dry glycol inlet to the glycol contact tower as near as practical to the glycol contact tower.

(c) You must install the shutdown valve (SDV) on the wet glycol outlet from the glycol contact tower as near as practical to the glycol contact tower.

Back to Top

§250.858 Gas compressors.

(a) You must equip compressor installations with the following protective equipment as required in API RP 14C, sections A.4 and A.8 (incorporated by reference as specified in §250.198).

(1) A pressure safety high (PSH) sensor, a pressure safety low (PSL) sensor, a pressure safety valve (PSV), a level safety high (LSH) sensor, and a level safety low (LSL) sensor to protect each interstage and suction scrubber.

(2) A temperature safety high (TSH) sensor in the discharge piping of each compressor cylinder or case discharge.

(3) You must design the PSH and PSL sensors and LSH controls protecting compressor suction and interstage scrubbers to actuate automatic SDVs 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 SDVs installed in compressor suction and fuel gas piping must 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 the suction side of a compressor must be diverted to the pipeline, diverted to a flare or vent in accordance with §§250.1160 or 250.1161, or shut-in at the wellhead.

(4) You must install a blowdown valve on the discharge line of all compressor installations that are 1,000 horsepower (746 kilowatts) or greater.

(b) Once system pressure has stabilized, you must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors whenever the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor,	Must be set no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line and sufficiently below the maximum discharge pressure to ensure actuation of the suction SDV	Must also be set sufficiently below (5 percent or 5 psi, whichever is greater) the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor,	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed	

Back to Top

§250.859 Firefighting systems.

(a) On fixed facilities, to protect all areas where production-handling equipment is located, you must install firefighting systems that meet the requirements of this paragraph. You must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors to protect all areas where production-handling equipment is located. Your firewater system must include installation of a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(1) Your firewater system must conform to API RP 14G (incorporated by reference as specified in §250.198).

(2) Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this pump operating time unless the District Manager has approved an alternate firefighting system. In addition:

(i) As of September 7, 2017, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system.

(ii) For electric-driven firewater pump drivers, to provide for a potential loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment.

(iii) You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.

(3) You must post, in a prominent place on the facility, a diagram of the firefighting system showing the location of all firefighting equipment.

(4) For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions.

(5) You must obtain approval from the District Manager before installing any firefighting system.

(6) All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system.

(b) On floating facilities, to protect all areas where production-handling equipment is located, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Your firewater system must conform to the USCG requirements for firefighting systems on floating facilities.

(c) Except as provided in paragraph (c)(1) and (2) of this section, on fixed and floating facilities, if you are required to maintain a firewater system and the system becomes inoperable, you must shut-in your production operations while making the necessary repairs. For fixed facilities only, you may continue your production operations on a temporary basis while you make the necessary repairs, provided that:

(1) You request that the appropriate District Manager approve the use of a chemical firefighting system on a temporary basis (for a period up to 7 days) while you make the necessary repairs;

(2) If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the District Manager may grant multiple extensions to your previously approved request to use a chemical firefighting system for periods up to 7 days each.

Back to Top

§250.860 Chemical firefighting system.

For fixed platforms:

(a) On minor unmanned platforms, you may use a U.S. Coast Guard type and size rating “B-II” portable dry chemical unit (with a minimum UL Rating (US) of 60-B:C) or a 30-pound portable dry chemical unit, in lieu of a water system, as long as you ensure that the unit is available on the platform when personnel are on board.

(1) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(2) An unmanned platform is one that is not attended 24 hours a day or one on which personnel are not quartered overnight.

(b) On major platforms and minor manned platforms, you may use a firefighting system using chemicals-only in lieu of a water-based system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control and would not increase the risk to human safety.

(1) A major platform is a structure with either six or more completions or zero to five completions with more than one item of production processing equipment.

(2) A minor platform is a structure with zero to five completions and no more than one item of production processing equipment.

(3) A manned platform is one that is attended 24 hours a day or one on which personnel are quartered overnight.

(c) On major platforms and minor manned platforms, to obtain approval to use a chemical-only fire prevention and control system in lieu of a water system under paragraph (b) of this section, you must submit to the District Manager:

(1) A justification for asserting that the use of a chemical system provides equivalent fire-protection control. The justification must address fire prevention, fire protection, fire control, and firefighting on the platform; and

(2) A risk assessment demonstrating that a chemical-only system would not increase the risk to human safety. You must provide the following and any other important information in your risk assessment:

For the use of a chemical firefighting system on major and minor manned platforms, you must provide the following in your risk assessment . . .	**Including . . .**
(i) Platform description	(A) The type and quantity of hydrocarbons (*i.e.,* natural gas, oil) that are produced, handled, stored, or processed at the facility.
	(B) The capacity of any tanks on the facility that you use to store either liquid hydrocarbons or other flammable liquids.
	(C) The total volume of flammable liquids (other than produced hydrocarbons) stored on the facility in containers other than bulk storage tanks. Include flammable liquids stored in paint lockers, storerooms, and drums.
	(D) If the facility is manned, provide the maximum number of personnel on board and the anticipated length of their stay.
	(E) If the facility is unmanned, provide the number of days per week the facility will be visited, the average length of time spent on the facility per visit, the mode of transportation, and whether or not transportation will be available at the facility while personnel are on board.
	(F) A diagram that depicts: quarters location, production equipment location, fire prevention and control equipment location, lifesaving appliances and equipment location, and evacuation plan escape routes from quarters and all manned working spaces to primary evacuation equipment.
(ii) Hazard assessment (facility specific)	(A) Identification of all likely fire initiation scenarios (including those resulting from maintenance and repair activities). For each scenario, discuss its potential severity and identify the ignition and fuel sources.
	(B) Estimates of the fire/radiant heat exposure that personnel could be subjected to. Show how you have considered designated muster areas and evacuation routes near fuel sources and have verified proper flare boom sizing for radiant heat exposure.
(iii) Human factors assessment (not facility specific)	(A) Descriptions of the fire-related training your employees and contractors have received. Include details on the length of training, whether the training was hands-on or classroom, the training frequency, and the topics covered during the training.
	(B) Descriptions of the training your employees and contractors have received in fire prevention, control of ignition sources, and control of fuel sources when the facility is occupied.
	(C) Descriptions of the instructions and procedures you have given to your employees and contractors on the actions they should take if a fire occurs. Include those instructions and procedures specific to evacuation. State how you convey this information to your employees and contractors on the platform.
(iv) Evacuation assessment (facility specific)	(A) A general discussion of your evacuation plan. Identify your muster areas (if applicable), both the primary and secondary evacuation routes, and the means of evacuation for both.
	(B) Description of the type, quantity, and location of lifesaving appliances available on the facility. Show how you have ensured that lifesaving appliances are located in the near vicinity of the escape routes.
	(C) Description of the types and availability of support vessels, whether the support vessels are equipped with a fire monitor, and the time needed for support vessels to arrive at the facility.
	(D) Estimates of the worst case time needed for personnel to evacuate the facility should a fire occur.
(v) Alternative protection assessment	(A) Discussion of the reasons you are proposing to use an alternative fire prevention and control system.
	(B) Lists of the specific standards used to design the system, locate the

	equipment, and operate the equipment/system.
	(C) Description of the proposed alternative fire prevention and control system/equipment. Provide details on the type, size, number, and location of the prevention and control equipment.
	(D) Description of the testing, inspection, and maintenance program you will use to maintain the fire prevention and control equipment in an operable condition. Provide specifics regarding the type of inspection, the personnel who conduct the inspections, the inspection procedures, and documentation and recordkeeping.
(vi) Conclusion	A summary of your technical evaluation showing that the alternative system provides an equivalent level of personnel protection for the specific hazards located on the facility.

(d) On major or minor platforms, if BSEE has approved your request to use a chemical-only fire suppressant system in lieu of a water system under paragraphs (b) and (c) of this section, and if you make an insignificant change to your platform subsequent to that approval, you must document the change and maintain the documentation for the life of the facility at either the facility or nearest field office for BSEE review and/or inspection. Do not submit this documentation to the District Manager. However, if you make a significant change to your platform (e.g., placing a storage vessel with a capacity of 100 barrels or more on the facility, adding production equipment), or if you plan to man an unmanned platform temporarily, you must submit a new request for approval, including an updated risk assessment if previously required, to the appropriate District Manager. You must maintain, for the life of the facility, the most recent documentation that you submitted to BSEE at the facility or nearest field office.

Back to Top

§250.861 Foam firefighting systems.

When you install foam firefighting systems as part of a firefighting system that protects production handling areas, you must:

(a) Annually conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration;

(b) Annually send samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing. You must have the sample tested to determine the specific gravity, pH, percentage of water dilution, and solid content. Based on these results, the foam must be certified by an authorized representative of the manufacturer as suitable firefighting foam consistent with the original manufacturer's specifications. The certification document must be readily accessible for field inspection. In lieu of sampling and certification, you may choose to replace the total inventory of foam with suitable new stock;

(c) Ensure that the quantity of concentrate meets design requirements, and that tanks or containers are kept full, with space allowed for expansion.

Back to Top

§250.862 Fire and gas-detection systems.

For production processing areas only:

(a) You must install fire (flame, heat, or smoke) sensors in all enclosed classified areas. You must install gas sensors in all inadequately ventilated, enclosed classified areas.

(1) 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. An acceptable method of providing adequate ventilation is one that provides 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.

(2) Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than 4 of their 6 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.

(3) 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).

(b) All detection systems must be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas-concentration levels must be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(c) 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. A gas detection system is not required for living quarters and doghouses that do not contain a gas source and that are not located in a classified area.

(d) The District Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(e) Fire- and gas-detection systems must be an approved type, and designed and installed in accordance with API RP 14C, API RP 14G, API RP 14F, API RP 14FZ, API RP 500, and API RP 505 (all incorporated by reference as specified in §250.198), provided that, if compliance with any provision of those standards would be in conflict with applicable regulations of the U.S. Coast Guard, compliance with the U.S. Coast Guard regulations controls.

Back to Top

§250.863 Electrical equipment.

You must design, install, and maintain electrical equipment and systems in accordance with the requirements in §250.114.

Back to Top

§250.864 Erosion.

You must have a program of erosion control in effect for wells or fields that have a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. You must maintain records for each lease that indicate the wells that have erosion-control programs in effect. You must also maintain the results of the programs for at least 2 years and make them available to BSEE upon request.

Back to Top

§250.865 Surface pumps.

(a) You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—A.7, Pumps (incorporated by reference as specified in §250.198).

(b) You must use pressure recording devices to establish the new operating pressure ranges for pump discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. Once system pressure has stabilized, pressure recording devices must be utilized to establish the new operating pressure ranges. The pressure recording devices must document the pressure range over time intervals that are no less than 4 hours and no more than 30 days long. You must only maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager.

(c) Pressure shut-in sensors must be set according to the following table (initial set points for pressure sensors must be set utilizing gauge readings and engineering design):

Type of sensor	Settings	Additional requirements
(1) PSH sensor	Must be no higher than 15 percent or 5 psi (whichever is greater) above the highest operating pressure of the discharge line	Must be set sufficiently below the maximum allowable working pressure of the discharge piping. The PSH must also be set at least 5 percent or 5 psi (whichever is greater) below the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates.
(2) PSL sensor	Must be set no lower than 15 percent or 5 psi (whichever is greater) below the lowest operating pressure of the discharge line in which it is installed	

(d) The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner.

(e) You may exclude the PSH and PSL sensors on small, low-volume pumps such as chemical injection-type pumps. This is acceptable if such a pump is used as a sump pump or transfer pump, has a discharge rating of less than $\frac{1}{2}$ gallon per minute (gpm), discharges into piping that is 1 inch or less in diameter, and terminates in piping that is 2 inches or larger in diameter.

(f) You must install a TSE in the immediate vicinity of all pumps in hydrocarbon service or those powered by platform fuel gas.

(g) The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver as appropriate for the pump type and service.

Back to Top

§250.866 Personnel safety equipment.

You must maintain all personnel safety equipment located on a facility, whether required or not, in good working condition.

Back to Top

§250.867 Temporary quarters and temporary equipment.

(a) You must equip temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in §250.198). The District Manager must approve the safety system/safety devices associated with the temporary quarters prior to installation.

(b) The District Manager may require you to install a temporary firewater system for temporary quarters in production processing areas or other classified areas.

(c) Temporary equipment associated with the production process system, including equipment used for well testing and/or well clean-up, must be approved by the District Manager.

(d) The District Manager must approve temporary generators that would require a change to the electrical one-line diagram in §250.842(a).

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

Back to Top

§250.868 Non-metallic piping.

On fixed OCS facilities, you may use non-metallic piping (such as that made from polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass) only in accordance with the requirements of §250.841(b).

Back to Top

§250.869 General platform operations.

(a) Surface or subsurface safety devices must not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing. You may take only the minimum number of safety devices out of service. Personnel must 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 must be flagged. A designated visual indicator must be used to identify the bypassed safety device. You must follow the monitoring procedures as follows:

(1) If you are using a non-computer-based system, meaning your safety system operates primarily with pneumatic supply or non-programmable electrical systems, you must monitor bypassed safety devices by positioning monitoring personnel at either the control panel for the bypassed safety device, or at the bypassed safety device, or at the component that the bypassed safety device would be monitoring when in service. You must also ensure that monitoring personnel are able to view all relevant essential operating conditions until all bypassed safety devices are placed back in service and are able to initiate shut-in action in the event of an abnormal condition.

(2) If you are using a computer-based technology system, meaning a computer-controlled electronic safety system such as supervisory control and data acquisition and remote terminal units, you must monitor bypassed safety devices by maintaining instantaneous communications at all times among remote monitoring personnel and the personnel performing maintenance, testing, or startup. Until all bypassed safety devices are placed back in service, you must also position monitoring personnel at a designated control station that is capable of the following:

(i) Displaying all relevant essential operating conditions that affect the bypassed safety device, well, pipeline, and process component. If electronic display of all relevant essential conditions is not possible, you must have field personnel monitoring the level gauges (sight glass) and pressure gauges in order to know the current operating conditions. You must be in communication with all field personnel monitoring the gauges;

(ii) Controlling the production process equipment and the entire safety system;

(iii) Displaying a visual indicator when safety devices are placed in the bypassed mode; and

(iv) Upon command, overriding the bypassed safety device and initiating shut-in action in the event of an abnormal condition.

(3) You must not bypass for startup any element of the emergency support system or other support system required by API RP 14C, Appendix C (incorporated by reference as specified in §250.198) without first receiving BSEE approval to depart from this operating procedure. These systems include, but are not limited to:

(i) The ESD system to provide a method to manually initiate platform shutdown by personnel observing abnormal conditions or undesirable events. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(ii) The fire loop system to sense the heat of a fire and initiate platform shutdown, and other fire detection devices (flame, thermal, and smoke) that are used to enhance fire detection capability. You do not have to receive approval from the District Manager for manual reset and/or initial charging of the system;

(iii) The combustible gas detection system to sense the presence of hydrocarbons and initiate alarms and platform shutdown before gas concentrations reach the lower explosive limit;

(iv) Adequate ventilation;

(v) The containment system to collect escaped liquid hydrocarbons and initiate platform shutdown;

(vi) Subsurface safety valves, including those that are self-actuated (subsurface-controlled SSSVs) or those that are activated by an ESD system and/or a fire loop (surface-controlled SSSV). You do not have to receive approval from the District Manager for routine operations in accordance with §250.817;

(vii) The pneumatic supply system; and

(viii) The system for discharging gas to the atmosphere.

(4) In instances where components of the ESD, as listed in paragraph (a)(3) of this section, are bypassed for maintenance, precautions must be taken to provide the equivalent level of protection that existed prior to the bypass.

(b) When wells are disconnected from producing facilities and blind flanged, or 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:

(1) Automatic fail-close SSVs on wellhead assemblies, and

(2) The PSH and PSL sensors in flowlines from wells.

(c) 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 testing in accordance with API RP 14C (incorporated by reference as specified in §250.198), or this subpart is not required, with the exception of the PSV, unless the vessel is open to the atmosphere.

(d) All open-ended lines connected to producing facilities and wells must be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(e) On all new production safety system installations, component process control devices and component safety devices must not be installed utilizing the same sensing points.

(f) All pneumatic control panels and computer based control stations must be labeled according to API RP 14C nomenclature.

Back to Top

§250.870 Time delays on pressure safety low (PSL) sensors.

(a) You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment. If the device may be bypassed for greater than 45 seconds, you must monitor the bypassed devices in accordance with §250.869(a). You must document on your field test records any use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:

(1) Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). Examples include sensors used in conjunction with the design of pump and compressor panels such as PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns.

(2) Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.,* the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure, and the PSL sensor clears). If a Class C safety device is bypassed, you must monitor the device until it is in full service.

(3) Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during startup and idle operations, (e.g., Class B/C bypass circuitry activates when a pump is shut down during normal operations). The PSL sensor remains bypassed until the pump's start circuitry is activated and either:

(i) The Class B timer expires no later than 45 seconds from start activation, or

(ii) The Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.

(b) If you do not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for a specified time period on process and product transport equipment during startup and idle operations, you must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49259, Sept. 28, 2018]

Back to Top

§250.871 Welding and burning practices and procedures.

All welding, burning, and hot-tapping activities must be conducted according to the specific requirements in §250.113.

Back to Top

§250.872 Atmospheric vessels.

(a) You must equip atmospheric vessels used to process and/or store liquid hydrocarbons or other Class I liquids as described in API RP 500 or 505 (both incorporated by reference in §250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference in §250.198). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage of refined liquid hydrocarbons or Class I liquids, are not required to be equipped with the protective equipment identified in API RP 14C, section A.5. The atmospheric vessels connected to the process system that contains a Class I liquid and the associated pumps must be reflected on the design documents listed in §250.842(a)(1) through (4) and (b)(3).

(b) You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality.

(c) You must ensure that all atmospheric vessels are designed, installed, and maintained to prevent pollution, including the displacement of oil out of an overboard water outlet, as required by §250.300(b)(3) and (4).

[83 FR 49259, Sept. 28, 2018]

Back to Top

§250.873 Subsea gas lift requirements.

If you choose to install a subsea gas lift system, you must design your system as approved in your DWOP or as follows:

(a) Design the gas lift supply pipeline in accordance with API RP 14C (incorporated by reference as specified in §250.198) for the gas lift supply system located on the platform.

(b) Meet the applicable requirements in the following table:

If your subsea gas lift system introduces the lift gas to the . . .	**Then you must install a**				**In addition, you must**
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in §250.198) gas-lift shutdown valve (GLSDV), and . . .	**FSV on the gas-lift supply pipeline . . .**	**PSHL on the gas-lift supply . . .**	**API Spec 6A and API Spec 6AV1 manual isolation valve . . .**	
(1) Subsea pipelines, pipeline risers, or manifolds via an external gas lift pipeline or umbilical	Meet all of the requirements for the BSDV described in §§250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical)	on the platform upstream (in-board) of the GLSDV	pipeline on the platform downstream (out board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold.

					(iii) Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).
(2) Subsea well(s) through the casing string via an external gas lift pipeline or umbilical	Meet all of the requirements for the GLSDV described in §§250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical)	on the platform upstream (in-board) of the GLSDV	pipeline on the platform down-stream (out board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. (ii) If your subsea tree or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. (iii) Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.
(3) Pipeline risers via a gas-lift line contained within the pipeline riser	Meet all of the requirements for the GLSDV described in §§250.835(a), (b), and (d) and 250.836 on the gas-lift supply pipeline	upstream (in-board) of the GLSDV	flowline upstream (in-board) of the FSV	downstream (out board) of the GLSDV	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser.
	Attach the GLSDV by flanged connection directly to the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the ANSI/API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser				(ii) Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (iii) Ensure that the gas-lift

					compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iv) Suspend and seal the gas-lift flowline contained within the production riser in a flanged ANSI/API Spec. 6A component such as an ANSI/API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of ANSI/API Spec. 6A. (v) Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. (vi) Ensure that this complete assembly is fire-rated for 30 minutes.

(c) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with gas lift,

(2) Electro-hydraulic control system with gas lift with loss of communications,

(3) Direct-hydraulic control system with gas lift.

(d) Follow the gas lift system valve testing requirements according to the following table:

Type of gas lift system	Valve	Allowable leakage rate	Testing frequency
(1) Gas lifting a subsea pipeline, pipeline riser, or	GLSDV	Zero leakage	Monthly, not to exceed 6

manifold via an external gas lift pipeline			weeks.
	GLIV	N/A	Function tested quarterly, not to exceed 120 days.
(2) Gas lifting a subsea well through the casing string via an external gas lift pipeline	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.
	GLIV	400 cc per minute of liquid or 15 scf per minute of gas.	Function tested quarterly, not to exceed 120 days
(3) Gas lifting the pipeline riser via a gas lift line contained within the pipeline riser	GLSDV	Zero leakage	Monthly, not to exceed 6 weeks.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 24707, May 29, 2019]

Back to Top

§250.874   Subsea water injection systems.

If you choose to install a subsea water injection system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Adhere to the water injection requirements described in API RP 14C (incorporated by reference as specified in §250.198) for the water injection equipment located on the platform. In accordance with §250.830, either a surface-controlled SSSV or a water injection valve (WIV) that is self-activated and not controlled by emergency shut-down (ESD) or sensor activation must be installed in a subsea water injection well.

(b) Equip a water injection pipeline with a surface FSV and water injection shutdown valve (WISDV) on the surface facility.

(c) Install a PSHL sensor upstream (in-board) of the FSV and WISDV.

(d) Use subsea tree(s), wellhead(s), connector(s), and tree valves, and surface-controlled SSSV or WIV associated with a water injection system that are rated for the maximum anticipated injection pressure.

(e) Consider the effects of hydrogen sulfide (H2S) when designing your water flood system, as required by §250.805.

(f) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with water injection,

(2) Electro-hydraulic control system with water injection with loss of communications, and

(3) Direct-hydraulic control system with water injection.

(g) Comply with the following injection valve testing requirements:

(1) You must test your injection valves as provided in the following table:

Valve	**Allowable leakage rate**	**Testing frequency**
(i) WISDV	Zero leakage	Monthly, not to exceed 6 weeks between tests.
(ii) Surface-controlled SSSV or WIV	400 cc per minute of liquid or 15 scf per minute of gas	Semiannually, not to exceed 6 calendar months between tests.

(2) If a designated USV on a water injection well fails the applicable test under §250.880(c)(4)(ii), you must notify the appropriate District Manager and request approval to designate another ANSI/API Spec 6A and API Spec. 6AV1 (both incorporated by reference in §250.198) certified subsea valve as your USV.

(3) If a USV on a water injection well fails the test and the surface-controlled SSSV or WIV cannot be tested as required under (g)(1)(ii) of this section because of low reservoir pressure, you must submit a request to the appropriate District Manager with an alternative plan that ensures subsea shutdown capabilities.

(h) If you experience a loss of communications during water injection operations, you must comply with the following:

(1) Notify the appropriate District Manager within 12 hours after detecting loss of communication; and

(2) Obtain approval from the appropriate District Manager to continue to inject during the loss of communication.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

Back to Top

§250.875   Subsea pump systems.

If you choose to install a subsea pump system, your system must comply with your approved DWOP, which must meet the following minimum requirements:

(a) Include the installation of an isolation valve at the inlet of your subsea pump module.

(b) Include a PSHL sensor upstream of the BSDV, if the maximum possible discharge pressure of the subsea pump operating in a dead head condition (that is the maximum shut-in tubing pressure at the pump inlet and a closed BSDV) is less than the MAOP of the associated pipeline.

(c) If the maximum possible discharge pressure of the subsea pump operating in a dead head situation could be greater than the MAOP of the pipeline:

(1) Include, at minimum, 2 independent functioning PSHL sensors upstream of the subsea pump and 2 independent functioning PSHL sensors downstream of the pump, that:

(i) Are operational when the subsea pump is in service; and

(ii) Will, when activated, shut down the subsea pump, the subsea inlet isolation valve, and either the designated USV1, the USV2, or the alternate isolation valve.

(iii) If more than 2 PSHL sensors are installed both upstream and downstream of the subsea pump for operational flexibility, then 2 out of 3 voting logic may be implemented in which the subsea pump remains operational provided a minimum of 2 independent PSHL sensors are functional both upstream and downstream of the pump.

(2) Interlock the subsea pump motor with the BSDV to ensure that the pump cannot start or operate when the BSDV is closed, incorporate at a minimum the following permissive signals into the control system for your subsea pump, and ensure that the subsea pump is not able to be started or re-started unless:

(i) The BSDV is open;

(ii) All automated valves downstream of the subsea pump are open;

(iii) The upstream subsea pump isolation valve is open; and

(iv) All parameters associated with the subsea pump operation (e.g., pump temperature high, pump vibration high, pump suction pressure high, pump discharge pressure high, pump suction flow low) must be cleared (*i.e.,* within operational limits) or continuously monitored by personnel who observe visual indicators displayed at a designated control station and have the capability to initiate shut-in action in the event of an abnormal condition.

(3) Monitor the separator for seawater.

(4) Ensure that the subsea pump systems are controlled by an electro-hydraulic control system.

(d) Follow the valve closure times and hydraulic bleed requirements according to your approved DWOP for the following:

(1) Electro-hydraulic control system with a subsea pump;

(2) A loss of communication with the subsea well(s) and not a loss of communication with the subsea pump control system without an ESD or sensor activation;

(3) A loss of communication with the subsea pump control system, and not a loss of communication with the subsea well(s);

(4) A loss of communication with the subsea well(s) and the subsea pump control system.

(e) For subsea pump testing:

(1) Perform a complete subsea pump function test, including full shutdown, after any intervention or changes to the software and equipment affecting the subsea pump; and

(2) Test the subsea pump shutdown, including PSHL sensors both upstream and downstream of the pump, each quarter (not to exceed 120 days between tests). This testing may be performed concurrently with the ESD function test required by §250.880(c)(4)(v).

Back to Top

§250.876 Fired and exhaust heated components.

No later than September 7, 2018, and at least once every 5 years thereafter, you must have qualified third-party inspect, and then you must repair or replace, as needed, the fire tube for tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make the documentation available to BSEE upon request.

[83 FR 49262, Sept. 28, 2018]

Back to Top

§§250.877-250.879 [Reserved]

Back to Top

Safety Device Testing

Back to Top

§250.880 Production safety system testing.

(a) *Notification.* You must:

(1) Notify the District Manager at least 72 hours before you commence initial production on a facility as required in §250.800(a)(2), in order for BSEE to conduct the preproduction inspection of the integrated safety system.

(2) Notify the District Manager upon commencement of production so that BSEE may conduct a complete inspection.

(3) Notify the District Manager and receive BSEE approval before you perform any subsea intervention that modifies the existing subsea infrastructure in a way that may affect the casing monitoring capabilities and testing frequencies specified in the table set forth in paragraph (c)(4) of this section.

(b) *Testing methodologies.* You must:

(1) Test safety valves and other equipment at the intervals specified in the tables set forth in paragraph (c) of this section or more frequently if operating conditions warrant; and

(2) Perform testing and inspections in accordance with API RP 14C, Appendix D (incorporated by reference as specified in §250.198), and the additional requirements specified in the tables of this section or as approved in the DWOP for your subsea system.

(c) *Testing frequencies.* You must:

(1) Comply with the following testing requirements for subsurface safety devices on dry tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells)	Semi-annually, not to exceed 6 calendar months between tests. Also test in place when first installed or reinstalled. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in §250.198) to ensure proper operation.
(ii) Subsurface-controlled SSSVs	Semi-annually, not to exceed 6 calendar months between tests for valves not installed in a landing nipple and 12 months for valves installed in a landing nipple. The valve must be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced.
(iii) Tubing plug	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the plug must be removed, repaired, and reinstalled or replaced. An additional tubing plug may be installed in lieu of removal.
(iv) Injection valves	Semi-annually, not to exceed 6 calendar months between tests. Test by opening the well to possible flow. If a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired and reinstalled or replaced.

(2) Comply with the following testing requirements for surface valves:

Item name	Testing frequency and requirements
(i) PSVs	Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing. The main valve piston must be lifted during this test.
(ii) Automatic inlet SDVs that are actuated by a sensor on a vessel or compressor	Once each calendar month, not to exceed 6 weeks between tests.
(iii) SDVs in	Once each calendar month, not to exceed 6 weeks between tests.

liquid discharge lines and actuated by vessel low-level sensors	
(iv) SSVs	Once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API STD 6AV2 (incorporated by reference in §250.198). If an SSV does not operate properly or if any gas and/or liquid fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(v) Flowline FSVs	Once each calendar month, not to exceed 6 weeks between tests. All flowline FSVs must be tested, including those installed on a host facility in lieu of being installed at a satellite well. You must test flowline FSVs for leakage in accordance with the test procedure specified in API RP 14C (incorporated by reference as specified in §250.198). If leakage measured exceeds a liquid flow of 400 cubic centimeters per minute or a gas flow of 15 standard cubic feet per minute, the FSV must be repaired or replaced.

(3) Comply with the following testing requirements for surface safety systems and devices:

Item name	**Testing frequency and requirements**
(i) Pumps for firewater systems	Must be inspected and operated according to API RP 14G, Section 7.2 (incorporated by reference as specified in §250.198).
(ii) Fire- (flame, heat, or smoke) and gas detection systems	Must be tested for operation and recalibrated every 3 months, not to exceed 120 days between tests, provided that testing can be performed in a non-destructive manner. Open flame or devices operating at temperatures that could ignite a methane-air mixture must not be used. All combustible gas-detection systems must be calibrated every 3 months.
(iii) ESD systems	(A) Pneumatic based ESD systems must be tested for operation at least once each calendar month, not to exceed 6 weeks between tests. You must conduct the test 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. All stations must be checked for functionality at least once each calendar month, not to exceed 6 weeks between tests. No station may be reused until all stations have been tested. (B) Electronic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been tested. (C) Electronic/pneumatic based ESD systems must be tested for operation at least once every 3 calendar months, not to exceed 120 days between tests. The test must be conducted by alternating ESD stations to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation. All stations must be checked for functionality at least once every 3 calendar months, not to exceed 120 days between checks. No station may be reused until all stations have been used.
(iv) TSH devices	Must be tested for operation annually, not to exceed 12 calendar months between tests, excluding those addressed in paragraph (c)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.
(v) TSH shutdown controls installed on compressor installations that can be nondestructively tested	Must be tested every 6 months and repaired or replaced as necessary.
(vi) Burner safety low	Must be tested annually, not to exceed 12 calendar months between tests.
(vii) Flow safety low devices	Must be tested annually, not to exceed 12 calendar months between tests.
(viii) Flame, spark, and detonation arrestors	Must be visually inspected annually, not to exceed 12 calendar months between inspections.
(ix) Electronic pressure transmitters and level sensors: PSH and PSL; LSH and LSL	Must be tested at least once every 3 months, not to exceed 120 days between tests.
(x) Pneumatic/electronic switch PSH and PSL; pneumatic/electronic switch/electric analog with mechanical linkage LSH and LSL controls	Must be tested at least once each calendar month, not to exceed 6 weeks between tests.

(4) Comply with the following testing requirements for subsurface safety devices and associated systems on

subsea tree wells:

Item name	Testing frequency, allowable leakage rates, and other requirements
(i) Surface-controlled SSSVs (including devices installed in shut-in and injection wells)	Tested semiannually, not to exceed 6 months between tests. If the device does not operate properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the device must be removed, repaired, and reinstalled or replaced. Testing must be according to ANSI/API RP 14B (incorporated by reference in §250.198) to ensure proper operation, or as approved in your DWOP.
(ii) USVs	Tested at least once every 3 calendar months, not to exceed 120 days between tests. If the device does not function properly, or if a liquid leakage rate > 400 cubic centimeters per minute or a gas leakage rate > 15 standard cubic feet per minute is observed, the valve must be removed, repaired, and reinstalled or replaced.
(iii) BSDVs	Tested at least once each calendar month, not to exceed 6 weeks between tests. Valves must be tested for both operation and leakage. You must test according to API STD 6AV2 for SSVs (incorporated by reference in §250.198). If a BSDV does not operate properly or if any fluid flow is observed during the leakage test, the valve must be immediately repaired or replaced.
(iv) Electronic ESD logic	Tested at least once each calendar month, not to exceed 6 weeks between tests.
(v) Electronic ESD function	Tested at least once every 3 calendar months, not to exceed 120 days between tests. Shut-in at least one well during the ESD function test. If multiple wells are tied back to the same platform, a different well should be shut-in with each quarterly test.

(d) *Subsea wells.* (1) Any subsea well that is completed and disconnected from monitoring capability may not be disconnected for more than 24 months, unless authorized by BSEE.

(2) Any subsea well that is completed and disconnected from monitoring capability for more than 6 months must meet the following testing and other requirements:

(i) Each well must have 3 pressure barriers:

(A) A closed and tested surface-controlled SSSV,

(B) A closed and tested USV, and

(C) One additional closed and tested tree valve.

(ii) For new completed wells, prior to the rig leaving the well, the pressure barriers must be tested as follows:

(A) The surface-controlled SSSV must be tested for leakage in accordance with §250.828(c);

(B) The USV and other pressure barrier must be tested to confirm zero leakage rate.

(iii) A sealing pressure cap must be installed on the flowline connection hub until the flowline is installed and connected. The pressure cap must be designed to accommodate monitoring for pressure between the production wing valve and cap. The pressure cap must also be designed so that a remotely operated vehicle can bleed pressure off, monitor for buildup, and confirm barrier integrity.

(iv) Pressure monitoring at the sealing pressure cap on the flowline connection hub must be performed in each well at intervals not to exceed 12 months from the time of initial testing of the pressure barrier (prior to demobilizing the rig from the field).

(v) You must have a drilling vessel capable of intervention into the disconnected well in the field or readily accessible for use until the wells are brought on line.

[81 FR 60918, Sept. 7, 2016, as amended at 83 FR 49262, Sept. 28, 2018]

Back to Top

§§250.881-250.889 [Reserved]

Back to Top

Records and Training

Back to Top

§250.890 Records.

(a) You must maintain records that show the present status and history of each safety device. Your records must include dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

(b) You must maintain these records for at least 2 years. You must maintain the records at your field office nearest the OCS facility and a secure onshore location. These records must be available for review by a representative of

BSEE.

(c) You must submit to the appropriate District Manager a contact list for all OCS facilities at least annually or when contact information is revised. The contact list must include:

(1) Designated operator name;

(2) Designated primary point of contact for the facility;

(3) Facility phone number(s), if applicable;

(4) Facility fax number, if applicable;

(5) Facility radio frequency, if applicable;

(6) Facility helideck rating and size, if applicable; and

(7) Facility records location if not contained on the facility.

Back to Top

§250.891 Safety device training.

You must ensure that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices, and personnel operating production platforms (including, but not limited to, separation, dehydration, compression, sweetening, and metering operations), are trained in accordance with the procedures in subpart O and subpart S of this part.

Back to Top

§§250.892-250.899 [Reserved]

Back to Top

Subpart I—Platforms and Structures

Back to Top

General Requirements for Platforms

Back to Top

§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 BSEE and the USCG for the modification.
(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 BSEE 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 BSEE 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 through 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), BSEE will cancel the approved platform application 1 year after the approval has been granted if the platform has not been installed. If BSEE cancels the approval, you must resubmit your platform application and receive BSEE 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, BSEE will identify the date when the installation approval will be cancelled (if installation has not occurred) during the application and approval process. If BSEE cancels your installation approval, you must resubmit your platform application and receive BSEE approval if you still plan to install the platform.

Back to Top

§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, (as specified in §250.198);

(4) American Petroleum Institute (API) Bulletin 2INT-DG, Interim Guidance for Design of Offshore Structures for Hurricane Conditions, (as incorporated by reference in §250.198);

(5) API Bulletin 2INT-EX, Interim Guidance for Assessment of Existing Offshore Structures for Hurricane Conditions, (as incorporated by reference in §250.198);

(6) API Bulletin 2INT-MET, Interim Guidance on Hurricane Conditions in the Gulf of Mexico, (as incorporated by reference in §250.198);

(7) API Recommend Practice (RP) 2A-WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design (as incorporated by reference in §250.198);

(8) API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, (as incorporated by reference in §250.198);

(9) API RP 2I, In-Service Inspection of Mooring Hardware for Floating Drilling Units (as incorporated by reference in §250.198);

(10) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), (as incorporated by reference in §250.198);

(11) API RP 2SK, Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures, (as incorporated by reference in §250.198);

(12) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, (as incorporated by reference in §250.198);

(13) API RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms, (as incorporated by reference in §250.198);

(14) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, (as incorporated by reference in §250.198);

(15) American Society for Testing and Materials (ASTM) Standard C 33-07, approved December 15, 2007, Standard Specification for Concrete Aggregates (as incorporated by reference in §250.198);

(16) ASTM Standard C 94/C 94M-07, approved January 1, 2007, Standard Specification for Ready-Mixed Concrete (as incorporated by reference in §250.198);

(17) ASTM Standard C 150-07, approved May 1, 2007, Standard Specification for Portland Cement (as incorporated by reference in §250.198);

(18) ASTM Standard C 330-05, approved December 15, 2005, Standard Specification for Lightweight Aggregates for Structural Concrete (as incorporated by reference in §250.198);

(19) ASTM Standard C 595-08, approved January 1, 2008, Standard Specification for Blended Hydraulic Cements (as incorporated by reference in §250.198);

(20) AWS D1.1, Structural Welding Code—Steel, including Commentary, (as incorporated by reference in §250.198);

(21) AWS D1.4, Structural Welding Code—Reinforcing Steel, (as incorporated by reference in §250.198);

(22) AWS D3.6M, Specification for Underwater Welding, (as incorporated by reference in §250.198);

(23) NACE Standard MR0175, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, (as incorporated by reference 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 (as incorporated by reference in §250.198).

(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	

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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.

Back to Top

§250.903 What records must I keep?

(a) You must compile, retain, and make available to BSEE 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 BSEE with the location of these records in the certification statement of your application for platform approval as required in §250.905(j).

Back to Top

Platform Approval Program

Back to Top

§250.904 What is the Platform Approval Program?

(a) The Platform Approval Program is the BSEE 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 BSEE 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.

Back to Top

§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 Verification 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 copies.
(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.
(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 §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" sk*etc*hes of jacket sections	You must submit one copy.
(j) A copy of the in-service inspection	This plan is described in §250.919	You must submit one copy.

plan		
(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.		

Back to Top

§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) Liquefaction, 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.

Back to Top

§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.

Back to Top

§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 (as incorporated by reference in §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 fatigue analysis must indicate a minimum 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

Platform Verification Program

Back to Top

§250.909 What is the Platform Verification Program?

The Platform Verification Program is the BSEE 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.

Back to Top

§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 BSEE and the USCG.

(d) The applicability of Platform Verification Program requirements to other types of facilities will be determined by BSEE on a case-by-case basis.

Back to Top

§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.

Back to Top

§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 to BSEE with or subsequent to the submittal of your Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD) to BOEM. 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.

Back to Top

§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.

Back to Top

§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 BSEE requirements and procedures;

(7) The level of work to be performed by the CVA.

Back to Top

§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.

Back to Top

§250.916 What are the CVA's primary duties during the design phase?

(a) The CVA must use good engineering judgment 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.

Back to Top

§250.917 What are the CVA's primary duties during the fabrication phase?

(a) The CVA must use good engineering judgment 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 tolerances specified and adherence to those tolerances;
	(vii) The nondestructive examination requirements, and evaluation results of the specified examinations;
	(viii) Destructive testing requirements and results;
	(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.

Back to Top

§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.
(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.

Back to Top

Inspection, Maintenance, and Assessment of Platforms

Back to Top

§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 (as incorporated by reference 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 BSEE before you make major repairs of any damage unless you meet the requirements of §250.900(c).

Back to Top

§250.920 What are the BSEE 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 (as incorporated by reference in §250.198). If BSEE 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, inadequate deck height, or 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, incorporated by reference in §250.198, 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 BSEE 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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.

Back to Top

Subpart J—Pipelines and Pipeline Rights-of-Way

Back to Top

§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 as of the date a pipeline begins service.

(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 BSEE upon request.

(iv) If adjoining producing and transporting operators cannot agree on a transfer point, the BSEE Regional Supervisor and the appropriate Department of Transportation (DOT) pipeline official may jointly determine the transfer point.

(4) The transfer point serves as a regulatory boundary. An operator may request that the BSEE Regional Supervisor grant an exception to this requirement for an individual facility or area. The Regional Supervisor, in consultation with the appropriate DOT pipeline official 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, BSEE 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 BSEE Regional Supervisor recognize that valve as the last point BSEE will exercise its regulatory authority.

(9) A pipeline segment is not subject to BSEE 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 BSEE 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 BSEE 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 appropriate DOT pipeline official.

(13) A transporter who operates a pipeline regulated by DOT may request to operate under BSEE regulations governing pipeline operation and maintenance. Any subsequent repairs or modifications will also be subject to BSEE regulations governing design and construction.

(i) The operator's request must be in the form of a written petition to the appropriate DOT pipeline official and the BSEE Regional Supervisor.

(ii) The BSEE Regional Supervisor and the appropriate DOT pipeline official 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).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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).

Back to Top

§250.1002 Design requirements for DOI pipelines.

(a) The internal design pressure for steel pipe shall be determined in accordance with the following formula:

$$P = \frac{2(S)(t)}{D} \times (F)(E)(T)$$

View or download PDF

For limitations see section 841.121 of American National Standards Institute (ANSI) B31.8 (as incorporated by reference in §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 ANSI/API Spec 6A (as incorporated by reference in §250.198), ANSI/API Spec 6D (as incorporated by reference in §250.198), 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/ASME B16.5, ANSI/API Spec 6A, or the equivalent (as incorporated by reference in §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 ANSI/API Spec. 17J, as incorporated by reference in §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) (as incorporated by reference in §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 (as incorporated by reference 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.

[76 FR 64462, Oct. 18, 2011, as amended at 83 FR 49263, Sept. 28, 2018]

Back to Top

§250.1003 Installation, testing, and repair requirements for DOI pipelines.

(a)(1) Pipelines greater than $8\frac{5}{8}$ 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.

Back to Top

§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 (as incorporated by reference 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 ANSI/API Spec. 17J (as incorporated by reference 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.

[76 FR 64462, Oct. 18, 2011, as amended at 83 FR 49263, Sept. 28, 2018]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 Bureau of Safety and Environmental Enforcement (BSEE). 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.

Back to Top

§250.1011 [Reserved]

Back to Top

§250.1012 Required payments for pipeline right-of-way holders.

(a) You must pay ONRR, under the regulations at 30 CFR part 1218, 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	You must pay ONRR, under the regulations at 30 CFR part 1218, a rental of $5 per acre per

is located in water depths of less than 200 meters;	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 ONRR, under the regulations at 30 CFR part 1218, 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 ONRR, under the regulations at 30 CFR part 1218, 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 1218.54. If you fail to make a payment that is late after written notice from ONRR, BSEE may initiate cancellation of the right-of-use grant and easement under §250.1013.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 BSEE 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 BSEE (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 BSEE regional office.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 30 CFR 550.1011. 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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.

Back to Top

Subpart K—Oil and Gas Production Requirements

Back to Top

General

Back to Top

§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.

Back to Top

Well Tests and Surveys

Back to Top

§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 BSEE-0126, 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 BSEE-0128, 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 semiannual 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 BSEE-0126.

Back to Top

§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) A BSEE 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.

Back to Top

§§250.1153-250.1155 [Reserved]

Back to Top

Approvals Prior to Production

Back to Top

§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 BSEE 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

Production Rates

Back to Top

§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.

Back to Top

Flaring, Venting, and Burning Hydrocarbons

Back to Top

§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.
(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) submitted to BOEM.

(c) The Regional Supervisor may establish alternative approval procedures to cover situations when you cannot contact the BSEE 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 30 CFR part 1202. You must value any gas or liquid hydrocarbons avoidably lost or wasted under the provisions of 30 CFR part 1206.

(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.

Back to Top

§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.

Back to Top

§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 30 CFR part 1202. You must value any liquid hydrocarbons avoidably lost or wasted under the provisions of 30 CFR part 1206.

Back to Top

§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 Office of Natural Resources Revenue on Form ONRR-4054 (Oil and Gas Operations Report), in accordance with 30 CFR 1210.102.

(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 BSEE representatives.

(2) After 2 years, you must maintain the records, allow BSEE 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 BSEE representatives.

(ii) After 2 years, you must maintain the recordings, allow BSEE 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.

Back to Top

§250.1164 What are the requirements for flaring or venting gas containing H2S?

(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 submitted to BOEM, 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 30 CFR 550.303, to determine the potential effect of facility emissions. The Regional Supervisor may require monitoring and reporting, or may restrict or prohibit flaring, under 30 CFR 550.303 and 30 CFR 550.304.

(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.

Back to Top

Other Requirements

Back to Top

§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 BSEE 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 and any additional information required by the BSEE Regional Supervisor. You also must submit Form BOEM-0127 to BOEM along with the supporting data specified in BOEM regulations, 30 CFR part 550, subpart K.

(c) You must report to Office of Natural Resources Revenue the volumes of oil, gas, or other substances injected, produced, or produced for a second time under 30 CFR 1210.102.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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 BSEE and the State of Alaska, BSEE and the Alaska Oil and Gas Conservation Commission will jointly determine appropriate reporting requirements to minimize or eliminate duplicate reporting requirements.

(c) [Reserved]

Back to Top

§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 form identified in column 1 and for the approvals required under this subpart identified in columns 2 through 4:

	WPT BSEE-0126 (2 copies)	**Gas cap production**	**Downhole commingling**	**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				
(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.

Back to Top

Subpart L—Oil and Gas Production Measurement, Surface Commingling, and Security

Back to Top

§250.1200 Question index table.

The table in this section lists questions concerning Oil and Gas Production Measurement, Surface Commingling, and Security.

Frequently asked questions	CFR citation
1. What are the requirements for measuring liquid hydrocarbons?	§250.1202(a)
2. What are the requirements for liquid hydrocarbon royalty meters?	§250.1202(b)
3. What are the requirements for run tickets?	§250.1202(c)
4. What are the requirements for liquid hydrocarbon royalty meter provings?	§250.1202(d)
5. What are the requirements for calibrating a master meter used in royalty meter provings?	§250.1202(e)
6. What are the requirements for calibrating mechanical-displacement provers and tank provers?	§250.1202(f)
7. What correction factors must a lessee use when proving meters with a mechanical displacement prover, tank prover, or master meter?	§250.1202(g)
8. What are the requirements for establishing and applying operating meter factors for liquid hydrocarbons?	§250.1202(h)
9. Under what circumstances does a liquid hydrocarbon royalty meter need to be taken out of service, and what must a lessee do?	§250.1202(i)
10. How must a lessee correct gross liquid hydrocarbon volumes to standard conditions?	§250.1202(j)
11. What are the requirements for liquid hydrocarbon allocation meters?	§250.1202(k)
12. What are the requirements for royalty and inventory tank facilities?	§250.1202(l)
13. To which meters do BSEE requirements for gas measurement apply?	§250.1203(a)
14. What are the requirements for measuring gas?	§250.1203(b)
15. What are the requirements for gas meter calibrations?	§250.1203(c)
16. What must a lessee do if a gas meter is out of calibration or malfunctioning?	§250.1203(d)
17. What are the requirements when natural gas from a Federal lease is transferred to a gas plant before royalty determination?	§250.1203(e)
18. What are the requirements for measuring gas lost or used on a lease?	§250.1203(f)
19. What are the requirements for the surface commingling of production?	§250.1204(a)
20. What are the requirements for a periodic well test used for allocation?	§250.1204(b)
21. What are the requirements for site security?	§250.1205(a)
22. What are the requirements for using seals?	§250.1205(b)

Back to Top

§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 §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.

Pipeline (retrograde) condensate—liquid hydrocarbons which drop out of the separated gas stream at any point in a pipeline during transmission to shore.

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.

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).

Back to Top

§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 and procedures that will accurately measure the liquid hydrocarbons produced from a lease or unit to comply with the following additional API MPMS industry standards or API RP:

(i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

(ii) API MPMS, Chapter 5, Section 6 (incorporated by reference as specified in §250.198);

(iii) API MPMS, Chapter 5, Section 8 (incorporated by reference as specified in §250.198);

(iv) API MPMS, Chapter 11, Section 1 (incorporated by reference as specified in §250.198);

(v) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference as specified in §250.198);

(vi) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(vii) API MPMS, Chapter 21, Section 2 (incorporated by reference as specified in §250.198);

(viii) API MPMS, Chapter 21, Addendum to Section 2 (incorporated by reference as specified in §250.198);

(ix) API RP 86 (incorporated by reference as specified in §250.198);

(3) Use procedures and correction factors according to the applicable chapters of the API MPMS or RP as incorporated by reference in 30 CFR 250.198, including the following additional editions:

(i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

(ii) API MPMS, Chapter 5, Section 6 (incorporated by reference as specified in §250.198);

(iii) API MPMS, Chapter 5, Section 8 (incorporated by reference as specified in §250.198);

(iv) API MPMS Chapter 11, Section 1 (incorporated by reference as specified in §250.198);

(v) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference as specified in §250.198);

(vi) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(vii) API RP 86 (incorporated by reference as specified in §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 BSEE-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 §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 BSEE 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, including the following additional editions:

(i) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

(ii) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(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, including the following additional editions:

(1) API MPMS, Chapter 4, Section 8 (incorporated by reference as specified in §250.198);

(2) API MPMS Chapter 11, Section 1 (incorporated by reference as specified in §250.198);

(3) API MPMS Chapter 12, Section 2, Part 3 (incorporated by reference as specified in §250.198);

(4) API MPMS Chapter 12, Section 2, Part 4 (incorporated by reference as specified in §250.198);

(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 §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 BSEE 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 corrections factors and procedures in the API MPMS as incorporated by reference in 30 CFR 250.198, including: API MPMS Chapter 11, Section 1 (incorporated by reference as specified in §250.198).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18921, Mar. 29, 2012]

Back to Top

§250.1203 Gas measurement.

(a) *To which meters do BSEE requirements for gas measurement apply?* BSEE 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 and procedures to ensure accurate and verifiable measurement. You must follow the recommendations in API MPMS or RP and AGA as incorporated by reference in 30 CFR 250.198, including the following additional editions:

(i) API RP 86 (incorporated by reference as specified in §250.198);

(ii) AGA Report No. 7 (incorporated by reference as specified in §250.198);

(iii) AGA Report No. 9 (incorporated by reference as specified in §250.198);

(iv) AGA Report No. 10 (incorporated by reference as specified in §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.

(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 BSEE 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 BSEE 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 1212.

(5) Upon the request of the Regional Supervisor, you must provide copies of the records.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 18922, Mar. 29, 2012]

Back to Top

§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.

Back to Top

§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 BSEE-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 BSEE inspection.

Back to Top

Subpart M—Unitization

Back to Top

§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.

Back to Top

§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) BSEE 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 BSEE 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) BSEE orders or approves a suspension of operations under §250.170.

Back to Top

§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 Competitive Reservoir Development Program submitted to BSEE 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 BSEE Regional Supervisor, you and the other affected lessees must submit for approval a joint Competitive Reservoir Development Program. You must submit the joint Competitive Reservoir Development Program within 90 days after the Regional Supervisor makes a final determination that the reservoir is competitive. The joint Competitive Reservoir Development Program must provide for the development and/or production of the reservoir. You may submit supplemental Competitive Reservoir Development Programs for the Regional Supervisor's approval.

(d) If you and the other affected lessees cannot reach an agreement on a joint Competitive Reservoir Development Program, submitted to BSEE within the approved period of time, each lessee must submit a separate Competitive Reservoir Development Program to the Regional Supervisor. The Regional Supervisor will hold a hearing to resolve differences in the separate Competitive Reservoir Development Programs. If the differences in the separate programs are not resolved at the hearing and the Regional Supervisor determines that unitization is necessary under §250.1301(b), BSEE will initiate unitization under §250.1304.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§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. BSEE will maintain and provide a model unit agreement for you to follow. If BSEE revises the model, BSEE 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.

Back to Top

§250.1304   How will BSEE 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 BSEE 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, BSEE 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 BSEE provides all lessees of the proposed unit area written notice and an opportunity for a hearing. If you want BSEE 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) BSEE will not hold a hearing under this paragraph until at least 30 days after BSEE 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.

Back to Top

Subpart N—Outer Continental Shelf Civil Penalties

Back to Top

Outer Continental Shelf Lands Act Civil Penalties

Back to Top

§250.1400 How does BSEE begin the civil penalty process?

This subpart explains BSEEs 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 BSEE determines, on the basis of available evidence, that a violation occurred and a civil penalty review is appropriate, it will prepare a case file. BSEE will appoint a Reviewing Officer.

Back to Top

§250.1401 [Reserved]

Back to Top

§250.1402 Definitions.

Terms used in this subpart have the following meaning:

Case file means a BSEE document file containing information and the record of evidence related to the alleged violation.

Civil penalty means a fine. It is a BSEE regulatory enforcement tool used in addition to Notices of Incidents of Noncompliance and directed suspensions of production or other operations.

Reviewing Officer means a BSEE 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.

Back to Top

§250.1403 What is the maximum civil penalty?

The maximum civil penalty is $45,463 per day per violation.

[85 FR 12735, Mar. 4, 2020]

Back to Top

§250.1404 Which violations will BSEE review for potential civil penalties?

BSEE will review each of the following violations for potential civil penalties:

(a) Violations that you do not correct within the period BSEE grants;

(b) Violations that BSEE 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 553.

Back to Top

§250.1405 When is a case file developed?

BSEE 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.

Back to Top

§250.1406 When will BSEE 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 appropriate Leasing 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 appropriate Leasing 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 BOEM 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 30 CFR 556.53(d) through (f). 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 30 CFR part 556.56.

(d) If you do not either pay the penalty or file a timely appeal, BSEE 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.

Back to Top

Federal Oil and Gas Royalty Management Act Civil Penalties Definitions

Back to Top

§250.1450 What definitions apply to this subpart?

The terms used in this subpart have the same meaning as in 30 U.S.C. 1702.

Back to Top

Penalties After a Period To Correct

Back to Top

§250.1451 What may BSEE do if I violate a statute, regulation, order, or lease term relating to a Federal oil and gas lease?

(a) If we believe that you have not followed any requirement of a statute, regulation, order, or lease term for any Federal oil or gas lease, we may send you a Notice of Noncompliance informing you what the violation is and what you need to do to correct it to avoid civil penalties under 30 U.S.C. 1719(a) and (b).

(b) We will serve the Notice of Noncompliance by registered mail or personal service using the most current address on file as maintained by the BOEM Leasing Office in your respective Region.

Back to Top

§250.1452 What if I correct the violation?

The matter will be closed if you correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice (or within a longer time period specified in the Notice).

Back to Top

§250.1453 What if I do not correct the violation?

(a) We may send you a Notice of Civil Penalty if you do not correct all of the violations identified in the Notice of Noncompliance within 20 days after you receive the Notice of Noncompliance (or within a longer time period specified in that Notice). The Notice of Civil Penalty will tell you how much penalty you must pay. The penalty may be up to $500 per day, beginning with the date of the Notice of Noncompliance, for each violation identified in the Notice of Noncompliance for as long as you do not correct the violations.

(b) If you do not correct all of the violations identified in the Notice of Noncompliance within 40 days after you receive the Notice of Noncompliance (or 20 days following the expiration of a longer time period specified in that

Notice), we may increase the penalty to up to $5,000 per day, beginning with the date of the Notice of Noncompliance, for each violation for as long as you do not correct the violations.

Back to Top

§250.1454 How may I request a hearing on the record on a Notice of Noncompliance?

You may request a hearing on the record on a Notice of Noncompliance by filing a request within 30 days of the date you received the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

Back to Top

§250.1455 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may petition the Hearings Division (Departmental) of the Office of Hearings and Appeals, to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under §250.1472.

(1) You must file your petition within 45 calendar days of receiving the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in BOEM's regulations, 30 CFR part 550, subpart N. The posted amount must cover the unpaid principal and interest due for the Notice of Noncompliance, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§250.1456 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty, if you did not previously request a hearing on the record under §250.1454. If you did not request a hearing on the record on the Notice of Noncompliance under §250.1454, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive the Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203.

Back to Top

Penalties Without a Period To Correct

Back to Top

§250.1460 May I be subject to penalties without prior notice and an opportunity to correct?

The Federal Oil and Gas Royalty Management Act sets out several specific violations for which penalties accrue without an opportunity to first correct the violation.

(a) Under 30 U.S.C. 1719(c), you may be subject to penalties of up to $10,000 per day per violation for each day the violation continues if you:

(1) Fail or refuse to permit lawful entry, inspection, or audit; or

(2) Knowingly or willfully fail or refuse to notify the Secretary, within 5 business days after any well begins production on a lease site or allocated to a lease site, or resumes production in the case of a well which has been off production for more than 90 days, of the date on which production has begun or resumed.

(b) Under 30 U.S.C. 1719(d), you may be subject to civil penalties of up to $25,000 per day for each day each violation continues if you:

(1) Knowingly or willfully prepare, maintain, or submit false, inaccurate, or misleading reports, notices, affidavits, records, data, or other written information;

(2) Knowingly or willfully take or remove, transport, use or divert any oil or gas from any lease site without having

valid legal authority to do so; or

(3) Purchase, accept, sell, transport, or convey to another person, any oil or gas knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted.

Back to Top

§250.1461 How will BSEE inform me of violations without a period to correct?

We will inform you of any violation, without a period to correct, by issuing a Notice of Noncompliance and Civil Penalty explaining the violation, how to correct it, and the penalty assessment. We will serve the Notice of Noncompliance and Civil Penalty by registered mail or personal service using your address of record as specified under 30 CFR part 1218, Subpart H.

Back to Top

§250.1462 How may I request a hearing on the record on a Notice of Noncompliance regarding violations without a period to correct?

You may request a hearing on the record of a Notice of Noncompliance regarding violations without a period to correct by filing a request within 30 days after you receive the Notice of Noncompliance with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy Street, Arlington, Virginia 22203. You may do this regardless of whether you correct the violations identified in the Notice of Noncompliance.

Back to Top

§250.1463 Does my request for a hearing on the record affect the penalties?

(a) If you do not correct the violations identified in the Notice of Noncompliance regarding violations without a period to correct, the penalties will continue to accrue even if you request a hearing on the record.

(b) You may ask the Hearings Division (Departmental) to stay the accrual of penalties pending the hearing on the record and a decision by the Administrative Law Judge under §250.1472.

(1) You must file your petition within 45 calendar days after you receive the Notice of Noncompliance.

(2) To stay the accrual of penalties, you must post a bond or other surety instrument, or demonstrate financial solvency, using the standards and requirements as prescribed in BOEM's regulations, 30 CFR part 550, subpart N. The posted amount must cover the unpaid principal and interest due for the Notice of Noncompliance, plus the amount of any penalties accrued before the date a stay becomes effective.

(3) The Hearings Division will grant or deny the petition under 43 CFR 4.21(b).

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36150, June 6, 2016]

Back to Top

§250.1464 May I request a hearing on the record regarding the amount of a civil penalty if I did not request a hearing on the Notice of Noncompliance?

(a) You may request a hearing on the record to challenge only the amount of a civil penalty when you receive a Notice of Civil Penalty regarding violations without a period to correct, if you did not previously request a hearing on the record under §250.1462. If you did not request a hearing on the record on the Notice of Noncompliance under §250.1462, you may not contest your underlying liability for civil penalties.

(b) You must file your request within 10 days after you receive Notice of Civil Penalty with the Hearings Division (Departmental), Office of Hearings and Appeals, U.S. Department of the Interior, 801 North Quincy, Arlington, Virginia 22203.

Back to Top

General Provisions

Back to Top

§250.1470 How does BSEE decide what the amount of the penalty should be?

We determine the amount of the penalty by considering the severity of the violations, your history of compliance, and if you are a small business.

Back to Top

§250.1471 Does the penalty affect whether I owe interest?

If you do not pay the penalty by the date required under §250.1475(d), BSEE will assess you late payment interest on the penalty amount at the same rate interest is assessed under 30 CFR 1218.54.

Back to Top

§250.1472 How will the Office of Hearings and Appeals conduct the hearing on the record?

If you request a hearing on the record under §§250.1454, 250.1456, 250.1462, or 250.1464, the hearing will be conducted by a Departmental Administrative Law Judge from the Office of Hearings and Appeals. After the hearing, the Administrative Law Judge will issue a decision in accordance with the evidence presented and applicable law.

Back to Top

§250.1473 How may I appeal the Administrative Law Judge's decision?

If you are adversely affected by the Administrative Law Judge's decision, you may appeal that decision to the Interior Board of Land Appeals under 43 CFR part 4, subpart E.

Back to Top

§250.1474 May I seek judicial review of the decision of the Interior Board of Land Appeals?

Under 30 U.S.C. 1719(j), you may seek judicial review of the decision of the Interior Board of Land Appeals. A suit for judicial review in the District Court will be barred unless filed within 90 days after the final order.

Back to Top

§250.1475 When must I pay the penalty?

(a) You must pay the amount of the Notice of Civil Penalty issued under §250.1453 or §250.1461, if you do not request a hearing on the record under §250.1454, §250.1456, §250.1462, or §250.1464.

(b) If you request a hearing on the record under §250.1454, §250.1456, §250.1462, or §250.1464, but you do not appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals under §250.1473, you must pay the amount assessed by the Administrative Law Judge.

(c) If you appeal the determination of the Administrative Law Judge to the Interior Board of Land Appeals, you must pay the amount assessed in the IBLA decision.

(d) You must pay the penalty assessed within 40 days after:

(1) You received the Notice of Civil Penalty, if you did not request a hearing on the record under either §250.1454, §250.1456, §250.1462, or §250.1464;

(2) You received an Administrative Law Judge's decision under §250.1472, if you obtained a stay of the accrual of penalties pending the hearing on the record under §250.1455(b) or §250.1463(b) and did not appeal the Administrative Law Judge's determination to the IBLA under §250.1473;

(3) You received an IBLA decision under §250.1473 if the IBLA continued the stay of accrual of penalties pending its decision and you did not seek judicial review of the IBLA's decision; or

(4) A final non-appealable judgment of a court of competent jurisdiction is entered, if you sought judicial review of the IBLA's decision and the Department or the appropriate court suspended compliance with the IBLA's decision pending the adjudication of the case.

(e) If you do not pay, that amount is subject to collection under the provisions of §250.1477.

Back to Top

§250.1476 Can BSEE reduce my penalty once it is assessed?

Under 30 U.S.C. 1719(g), the Director or his or her delegate may compromise or reduce civil penalties assessed under this part.

Back to Top

§250.1477 How may BSEE collect the penalty?

(a) BSEE may use all available means to collect the penalty including, but not limited to:

(1) Requiring the lease surety, for amounts owed by lessees, to pay the penalty;

(2) Deducting the amount of the penalty from any sums the United States owes to you; and

(3) Using judicial process to compel your payment under 30 U.S.C. 1719(k).

(b) If the Department uses judicial process, or if you seek judicial review under §250.1474 and the court upholds assessment of a penalty, the court shall have jurisdiction to award the amount assessed plus interest assessed from the date of the expiration of the 90-day period referred to in §250.1474. The amount of any penalty, as finally determined, may be deducted from any sum owing to you by the United States.

Back to Top

Criminal Penalties

Back to Top

§250.1480 May the United States criminally prosecute me for violations under Federal oil and gas leases?

If you commit an act for which a civil penalty is provided at 30 U.S.C. 1719(d) and §250.1460(b), the United States may pursue criminal penalties as provided at 30 U.S.C. 1720, in addition to any authority for prosecution under other statutes.

Back to Top

Subpart O—Well Control and Production Safety Training

Back to Top

§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, deepwater well control, or production safety duties for the lessee.

Deepwater well control means well control when you are using a subsea BOP system.

Employee means direct employees of the lessees who are assigned well control, deepwater 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 BOEM-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 operations include, but are not limited to, separation, dehydration, compression, sweetening, and metering operations.

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.

Well completion/well workover means those operations following the drilling of a well that are intended to establish or restore production.

Well-control means methods used to minimize the potential for the well to flow or kick and to maintain control of the well in the event of flow or a kick. Well-control applies to drilling, well-completion, well-workover, abandonment, and well-servicing operations. It includes measures, practices, procedures and equipment, such as fluid flow monitoring, to ensure safe and environmentally protective drilling, completion, abandonment, and workover operations as well as the installation, repair, maintenance, and operation of surface and subsea well-control equipment.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012]

Back to Top

§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, deepwater well control, or production safety operations understand and can properly perform their duties.

Back to Top

§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, deepwater well control, and production safety duties. You must verify that your employees understand and can perform the assigned well control, deepwater well control, or production safety duties.

(b) If you conduct operations with a subsea BOP stack, your employees and contract personnel must be trained in deepwater well control. The trained employees and contract personnel must have a comprehensive knowledge of deepwater well control equipment, practices, and theory.

(c) 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, deepwater 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, deepwater 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.

(d) Upon request of the District Manager or Regional Supervisor, you must provide:

(1) Copies of training documentation for personnel involved in well control, deepwater well control, or production safety operations during the past 5 years; and

(2) A copy of your training plan.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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, deepwater 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, deepwater well control, or production safety duties; and

(c) Ensure that your contractors' training programs provide for periodic training and verification of well control, deepwater well control, or production safety knowledge and skills.

Back to Top

§250.1507 How will BSEE measure training results?

BSEE may periodically assess your training program, using one or more of the methods in this section.

(a) *Training system audit.* BSEE 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.* BSEE 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.* BSEE 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, deepwater well control, and production safety duties.

(d) *Hands-on production safety, simulator, or live well testing.* BSEE 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, deepwater well control, and production safety duties. You are responsible for the costs associated with this testing, excluding salary and travel costs for BSEE personnel.

Back to Top

§250.1508 What must I do when BSEE administers written or oral tests?

BSEE 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 BSEE 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).

Back to Top

§250.1509 What must I do when BSEE administers or requires hands-on, simulator, or other types of testing?

If BSEE 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 BSEE 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 BSEE personnel.

Back to Top

§250.1510 What will BSEE do if my training program does not comply with this subpart?

If BSEE 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 BSEE your training plan to address identified deficiencies;

(c) Assess civil/criminal penalties; or

(d) Initiate disqualification procedures.

Back to Top

Subpart P—Sulphur Operations

Back to Top

§250.1600 Performance standard.

Operations to discover, develop, and produce sulphur in the OCS shall be in accordance with a BOEM-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.

Back to Top

§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.

Back to Top

§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 and the applicable provisions of 30 CFR 550 subparts A, B, C, J and N.

(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 and the applicable provisions of 30 CFR 550, subpart K, where such provisions specifically are referenced in this subpart.

Back to Top

§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.

Back to Top

§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 §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.

Back to Top

§250.1605 Drilling requirements.

(a) *Sulphur leases.* 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 BSEE-0123, Application for Permit to Drill (APD), in accordance with §250.1617 of this subpart. After a drilling unit has been approved by a BSEE 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 30 CFR 550.211 through 550.228 and 30 CFR 550.241 through 550.262 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 time lapse 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 36151, June 6, 2016]

Back to Top

§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.

Back to Top

§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) 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. 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 BSEE 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.

Back to Top

§250.1612 Well-control drills.

Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in §250.711 or as approved by the District Manager.

[81 FR 26037, Apr. 29, 2016]

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§250.1617 Application for permit to drill.

(a) Before drilling a well under a BOEM-approved Exploration Plan, Development and Production Plan, or Development Operations Coordination Document, you must file Form BSEE-0123, 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 a BSEE 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 BSEE-0123 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.

Back to Top

§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 BSEE-0124, 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 BSEE-0124 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 BSEE-0124 shall be submitted in accordance with §250.186 of this part.

Back to Top

§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 BSEE-0125, End of Operations Report, or Form BSEE-0124, 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.

Back to Top

§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.

Back to Top

§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 BSEE review.

Back to Top

§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 BSEE-0124. 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 BSEE-0124 (or with Form BSEE-0123):

(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 BSEE-0125, 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 BSEE-0124 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.

Back to Top

§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.

Back to Top

§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 $^3/_4$ inch to $1^1/_4$ 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.

Back to Top

§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 BSEE 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 (as incorporated by reference in §250.198);

(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 (as incorporated by reference 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 (as incorporated by reference 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, as incorporated by reference in §250.198) and the related Safety Analysis Function Evaluation chart (API RP 14C, subsection 4.3c, as incorporated by reference 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 (as incorporated by reference in §250.198);

(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 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 (as incorporated by reference 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.

Back to Top

§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 (as specified in §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) (as incorporated by reference 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 (as specified in §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) (as incorporated by reference 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 (as incorporated by reference 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 (as incorporated by reference in §250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (as incorporated by reference 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 as incorporated by reference 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.

Back to Top

§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 (as incorporated by reference 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 BSEE 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.

Back to Top

§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 BSEE review.

Back to Top

§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).

Back to Top

§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.

Back to Top

§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.

Back to Top

Subpart Q—Decommissioning Activities

Back to Top

General

Back to Top

§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 BSEE and other agencies that have jurisdiction over decommissioning activities.

(b) *Obstructions* mean 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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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. Packers and bridge plugs used as qualified mechanical barriers must comply with

ANSI/API Spec. 11D1 (as incorporated by reference in §250.198). You must have two independent barriers, one being an ANSI/API Spec. 11D1 qualified mechanical barrier, in the exposed center wellbore prior to removing the tree and/or well control equipment;

(c) Remove all platforms and other facilities, except as provided in §§250.1725(a) and 250.1730.

(d) Decommission all pipelines;

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;

(f) Follow all applicable requirements of subpart G of this part; and

(g) 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.

[76 FR 64462, Oct. 18, 2011, as amended at 81 FR 26037, Apr. 29 2016; 84 FR 21984, May 15, 2019]

Back to Top

§250.1704 What decommissioning applications and reports must I submit and when must I submit them?

You must submit decommissioning applications, receive approval of those applications, and submit subsequent reports according to the requirements and deadlines in the following table.

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.
(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 BSEE-0124, 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,	(i) Include information required under §§250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under §250.731.
	(2) Before you install a subsea protective device,	Refer to §250.1722(a).
	(3) Before you remove any casing stub or mud line suspension	Refer to §250.1723.

	equipment and any subsea protective device,	
	(4) Within 30 days after you complete site clearance verification activities,	Include information required under §250.1743(a).
(h) Form BSEE-0125, End of Operations Report (EOR);	(1) Within 30 days after you complete a protective device trawl test,	Include information required under §250.1722(d).
	(2) Within 30 days after completion of decommissioning activity,	Include information required under §§250.1712 and 250.1721.
(i) A certified summary of expenditures for permanently plugging any well, removal of any platform or other facility, clearance of any site after wells have been plugged or platforms or facilities removed, and decommissioning of pipelines	Within 120 days after completion of each decommissioning activity specified in this paragraph	Submit to the Regional Supervisor a complete summary of expenditures actually incurred for each decommissioning activity (including, but not limited to, the use of rigs, vessels, equipment, supplies and materials; transportation of any kind; personnel; and services). Include in, or attach to, the summary a certified statement by an authorized representative of your company attesting to the truth, accuracy and completeness of the summary. The Regional Supervisor may provide specific instructions or guidance regarding how to submit the certified summary.
(j) If requested by the Regional Supervisor, additional information in support of any decommissioning activity expenditures included in a summary submitted under paragraph (i) of this section	Within a reasonable time as determined by the Regional Supervisor	The Regional Supervisor will review the summary and may provide specific instructions or guidance regarding the submission of additional information (including, but not limited to, copies of contracts and invoices), if requested, to complete or otherwise support the summary.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50896, Aug. 22, 2012; 80 FR 75810, Dec. 4, 2015; 81 FR 26037, Apr. 29, 2016; 81 FR 80591, Nov. 16, 2016; 84 FR 21984, May 15, 2019]

Back to Top

§§250.1705-250.1709 [Reserved]

Back to Top

Permanently Plugging Wells

Back to Top

§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.

Back to Top

§250.1711 When will BSEE order me to permanently plug a well?

BSEE 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.

Back to Top

§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 BSEE-0124, 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;

(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; and

(g) Certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements in the table in §250.1715. In addition to the requirements of §250.1715, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in §250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM (Form BSEE-0124).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012]

Back to Top

§250.1713 [Reserved]

Back to Top

§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.

Back to Top

§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 casing 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.
(11) Removed the barriers required in §250.420(b)(3) for the well to be completed	Two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in §250.420(b)(3) once the well is to be placed in a permanent or temporary abandonment.

(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).

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012; 81 FR 26038, Apr. 29, 2016]

Back to Top

§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 BSEE concurs, that you must use divers, and the seafloor sediment stability poses safety concerns; or

(3) The water depth is greater than 1,000 feet.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21985, May 15, 2019]

Back to Top

§250.1717 [Reserved]

Back to Top

Temporary Abandoned Wells

Back to Top

§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 BSEE-0124, 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. BSEE 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;

(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) Submit certification by a Registered Professional Engineer of the well abandonment design and procedures and that all plugs meet the requirements of paragraph (b) of this section. In addition to the requirements of paragraph (b) of this section, the Registered Professional Engineer must also certify the design will include two independent barriers, one of which must be a mechanical barrier, in the center wellbore as described in §250.420(b)(3). The Registered Professional Engineer must be registered in a State of the United States and have sufficient expertise and experience to perform the certification. You must submit this certification with your APM (Form BSEE-0124) required by §250.1712 of this part.

[76 FR 64462, Oct. 18, 2011, as amended at 77 FR 50900, Aug. 22, 2012; 81 FR 26038, Apr. 29, 2016]

Back to Top

§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 BSEE-0124, 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 BSEE 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 BSEE-0125, End of Operations Report (EOR) 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.

[76 FR 64462, Oct. 18, 2011, as amended at 84 FR 21985, May 15, 2019]

Back to Top

§250.1723 What must I do when it is no longer necessary to maintain a well in temporary abandoned status?

If you or BSEE 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 BSEE-0124, Application for Permit to Modify; and

(c) Clear the well site according to §§250.1740 through 250.1742.

Back to Top

Removing Platforms and Other Facilities

Back to Top

§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 BSEE 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 BSEE. 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.

Back to Top

§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.

Back to Top

§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/BSEE 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.

Back to Top

§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 BSEE 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).

Back to Top

§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.

Back to Top

§250.1730 When might BSEE 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.

Back to Top

§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 30 CFR part 585 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 585, 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 556 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 556 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.

Back to Top

Site Clearance for Wells, Platforms, and Other Facilities

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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 BSEE-0124, 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 it 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.

Back to Top

Pipeline Decommissioning

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

§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.

Back to Top

Subpart R [Reserved]

Back to Top

Subpart S—Safety and Environmental Management Systems (SEMS)

Back to Top

§250.1900 Must I have a SEMS program?

You must develop, implement, and maintain a safety and environmental management system (SEMS) program. Your SEMS program must address the elements described in §250.1902, American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75) (as incorporated by reference in §250.198), and other requirements as identified in this subpart.

(a) If there are any conflicts between the requirements of this subpart and API RP 75; COS-2-01, COS-2-03, or COS-2-04; or ISO/IEC 17011 (incorporated by reference as specified in §250.198), you must follow the requirements of this subpart.

(b) Nothing in this subpart affects safety or other matters under the jurisdiction of the Coast Guard.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

Back to Top

§250.1901 What is the goal of my SEMS program?

The goal of your SEMS program is to promote safety and environmental protection by ensuring all personnel aboard a facility are complying with the policies and procedures identified in your SEMS.

(a) To accomplish this goal, you must ensure that your SEMS program identifies, addresses, and manages safety, environmental hazards, and impacts during the design, construction, start-up, operation (including, but not limited to, drilling and decommissioning), inspection, and maintenance of all new and existing facilities, including mobile offshore drilling units (MODUs) when attached to the seabed and Department of the Interior (DOI) regulated pipelines.

(b) All personnel involved with your SEMS program must be trained to have the skills and knowledge to perform their assigned duties.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

Back to Top

§250.1902 What must I include in my SEMS program?

You must have a properly documented SEMS program in place and make it available to BSEE upon request as required by §250.1924(b).

(a) Your SEMS program must meet the minimum criteria outlined in this subpart, including the following SEMS program elements:

(1) General (see §250.1909)

(2) Safety and Environmental Information (see §250.1910)

(3) Hazards Analysis (see §250.1911)

(4) Management of Change (see §250.1912)

(5) Operating Procedures (see §250.1913)

(6) Safe Work Practices (see §250.1914)

(7) Training (see §250.1915)

(8) Mechanical Integrity (Assurance of Quality and Mechanical Integrity of Critical Equipment) (see §250.1916)

(9) Pre-startup Review (see §250.1917)

(10) Emergency Response and Control (see §250.1918)

(11) Investigation of Incidents (see §250.1919)

(12) Auditing (Audit of Safety and Environmental Management Program Elements) (*see* §250.1920)

(13) Recordkeeping (Records and Documentation) and additional BSEE requirements (*see* §250.1928)

(14) Stop Work Authority (SWA) (see §250.1930)

(15) Ultimate Work Authority (UWA) (see §250.1931)

(16) Employee Participation Plan (EPP) (see §250.1932)

(17) Reporting Unsafe Working Conditions (see §250.1933).

(b) You must include a job safety analysis (JSA) for OCS activities identified or discussed in your SEMS program (see §250.1911).

(c) Your SEMS program must meet or exceed the standards of safety and environmental protection of API RP 75 (as incorporated by reference in §250.198).

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

Back to Top

§250.1903 Acronyms and definitions.

Definitions listed in this section apply to this subpart and supersede definitions in API RP 75, Appendices D and E; COS-2-01, COS-2-03, and COS-2-04; and ISO/IEC 17011 (incorporated by reference as specified in §250.198).

(a) *Acronyms* used frequently in this subpart have the following meanings:

AB means Accreditation Body,

ASP means Audit Service Provider,

CAP means Corrective Action Plan,

COS means Center for Offshore Safety,

EPP means Employee Participation Plan,

ISO means International Organization for Standardization,

JSA means Job Safety Analysis,

MODU means Mobile Offshore Drilling Unit,

OCS means Outer Continental Shelf,

SEMS means Safety and Environmental Management Systems,

SWA means Stop Work Authority,

USCG means United States Coast Guard, and

UWA means Ultimate Work Authority.

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

Accreditation Body (AB) means a BSEE-approved independent third-party organization that assesses and accredits ASPs.

Audit Service Provider (ASP) means an independent third-party organization that demonstrates competence to conduct SEMS audits in accordance with the requirements of this subpart.

Corrective Action Plan (CAP) means a scheduled plan to correct deficiencies identified during an audit and that is developed by an operator following the issuance of an audit report.

Personnel means direct employee(s) of the operator and contracted workers.

Ultimate Work Authority (UWA) means the authority assigned to an individual or position to make final decisions relating to activities and operations on the facility.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20440, Apr. 5, 2013]

Back to Top

§250.1904 Special instructions.

(a) For purposes of this subpart, each and every reference in COS-2-01, COS-2-03, and COS-2-04 (incorporated by reference as specified in §250.198) to the term *deepwater* means the entire OCS, including all water depths.

(b) The BSEE does not incorporate by reference any requirement that you must be a COS member company. For purposes of this subpart, each and every reference in COS-2-01, COS-2-03, and COS-2-04 to the phrase *COS member company(ies)* means you, whether or not you are a COS member.

(c) For purposes of this subpart, each and every reference in the relevant sections of COS-2-01, COS-2-03, and COS-2-04 (incorporated by reference as specified in §250.198) to the *Center for Offshore Safety* or *COS* means *accreditation body* or *AB.*

(d) For purposes of this subpart, each and every reference in ISO/IEC 17011 (incorporated by reference as specified in §250.198) to *conformity assessment body (CAB)* means *ASP.*

[78 FR 20441, Apr. 5, 2013]

Back to Top

§§250.1905-250.1908 [Reserved]

Back to Top

§250.1909 What are management's general responsibilities for the SEMS program?

You, through your management, must require that the program elements discussed in API RP 75 (as incorporated by reference in §250.198) and in this subpart are properly documented and are available at field and office locations, as appropriate for each program element. You, through your management, are responsible for the development, support, continued improvement, and overall success of your SEMS program. Specifically you, through your management, must:

(a) Establish goals and performance measures, demand accountability for implementation, and provide necessary resources for carrying out an effective SEMS program.

(b) Appoint management representatives who are responsible for establishing, implementing and maintaining an effective SEMS program.

(c) Designate specific management representatives who are responsible for reporting to management on the performance of the SEMS program.

(d) At intervals specified in the SEMS program and at least annually, review the SEMS program to determine if it continues to be suitable, adequate and effective (by addressing the possible need for changes to policy, objectives, and other elements of the program in light of program audit results, changing circumstances and the commitment to continual improvement) and document the observations, conclusions and recommendations of that review.

(e) Develop and endorse a written description of your safety and environmental policies and organizational structure that define responsibilities, authorities, and lines of communication required to implement the SEMS program.

(f) Utilize personnel with expertise in identifying safety hazards, environmental impacts, optimizing operations, developing safe work practices, developing training programs and investigating incidents.

(g) Ensure that facilities are designed, constructed, maintained, monitored, and operated in a manner compatible with applicable industry codes, consensus standards, and generally accepted practice as well as in compliance with all applicable governmental regulations.

(h) Ensure that management of safety hazards and environmental impacts is an integral part of the design, construction, maintenance, operation, and monitoring of each facility.

(i) Ensure that suitably trained and qualified personnel are employed to carry out all aspects of the SEMS program.

(j) Ensure that the SEMS program is maintained and kept up to date by means of periodic audits to ensure effective performance.

Back to Top

§250.1910 What safety and environmental information is required?

(a) You must require that SEMS program safety and environmental information be developed and maintained for any facility that is subject to the SEMS program.

(b) SEMS program safety and environmental information must include:

(1) Information that provides the basis for implementing all SEMS program elements, including the requirements of hazard analysis (§250.1911);

(2) process design information including, as appropriate, a simplified process flow diagram and acceptable upper and lower limits, where applicable, for items such as temperature, pressure, flow and composition; and

(3) mechanical design information including, as appropriate, piping and instrument diagrams; electrical area classifications; equipment arrangement drawings; design basis of the relief system; description of alarm, shutdown, and interlock systems; description of well control systems; and design basis for passive and active fire protection features and systems and emergency evacuation procedures.

Back to Top

§250.1911 What hazards analysis criteria must my SEMS program meet?

You must ensure that a hazards analysis (facility level) and a JSA (operations/task level) are developed and implemented for all of your facilities and activities identified or discussed in your SEMS. You must document and maintain a current analysis for each operation covered by this section for the life of the operation at the facility. You must update the analysis when an internal audit is conducted to ensure that it is consistent with your facility's current operations.

(a) *Hazards analysis (facility level).* The hazards analysis must be appropriate for the complexity of the operation and must identify, evaluate, and manage the hazards involved in the operation.

(1) The hazards analysis must address the following:

(i) Hazards of the operation;

(ii) Previous incidents related to the operation you are evaluating, including any incident in which you were issued an Incident of Noncompliance or a civil or criminal penalty;

(iii) Control technology applicable to the operation your hazards analysis is evaluating; and

(iv) A qualitative evaluation of the possible safety and health effects on employees, and potential impacts to the human and marine environments, which may result if the control technology fails.

(2) The hazards analysis must be performed by a person(s) with experience in the operations being evaluated. These individuals also need to be experienced in the hazards analysis methodologies being employed.

(3) You should assure that the recommendations in the hazards analysis are resolved and that the resolution is documented.

(4) A single hazards analysis can be performed to fulfill the requirements for simple and nearly identical facilities, such as well jackets and single well caissons. You can apply this single hazards analysis to simple and nearly identical facilities after you verify that any site-specific deviations are addressed in each of your SEMS program elements.

(b) *JSA.* You must ensure a JSA is prepared, conducted, and approved for OCS activities that are identified or discussed in your SEMS program. The JSA is a technique used to identify risks to personnel associated with their job activities. The JSAs are also used to determine the appropriate mitigation measures needed to reduce job risks to personnel. The JSA must include all personnel involved with the job activity.

(1) You must ensure that your JSA identifies, analyzes, and records:

(i) The steps involved in performing a specific job;

(ii) The existing or potential safety, health, and environmental hazards associated with each step; and

(iii) The recommended action(s) and/or procedure(s) that will eliminate or reduce these hazards, the risk of a workplace injury or illness, or environmental impacts.

(2) The immediate supervisor of the crew performing the job onsite must conduct the JSA, sign the JSA, and ensure that all personnel participating in the job understand and sign the JSA.

(3) The individual you designate as being in charge of the facility must approve and sign all JSAs before personnel start the job.

(4) If a particular job is conducted on a recurring basis, and if the parameters of these recurring jobs do not change, then the person in charge of the job may decide that a JSA for each individual job is not required. The parameters you must consider in making this determination include, but are not limited to, changes in personnel, procedures, equipment, and environmental conditions associated with the job.

(c) All personnel, which includes contractors, must be trained in accordance with the requirements of §250.1915. You must also verify that contractors are trained in accordance with §250.1915 prior to performing a job.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

Back to Top

§250.1912 What criteria for management of change must my SEMS program meet?

(a) You must develop and implement written management of change procedures for modifications associated with the following:

(1) Equipment,

(2) Operating procedures,

(3) Personnel changes (including contractors),

(4) Materials, and

(5) Operating conditions.

(b) Management of change procedures do not apply to situations involving replacement in kind (such as, replacement of one component by another component with the same performance capabilities).

(c) You must review all changes prior to their implementation.

(d) The following items must be included in your management of change procedures:

(1) The technical basis for the change;

(2) Impact of the change on safety, health, and the coastal and marine environments;

(3) Necessary time period to implement the change; and

(4) Management approval procedures for the change.

(e) Employees, including contractors whose job tasks will be affected by a change in the operation, must be informed of, and trained in, the change prior to startup of the process or affected part of the operation; and

(f) If a management of change results in a change in the operating procedures of your SEMS program, such changes must be documented and dated.

Back to Top

§250.1913 What criteria for operating procedures must my SEMS program meet?

(a) You must develop and implement written operating procedures that provide instructions for conducting safe and environmentally sound activities involved in each operation addressed in your SEMS program. These procedures must include the job title and reporting relationship of the person or persons responsible for each of the facility's operating areas and address the following:

(1) Initial startup;

(2) Normal operations;

(3) All emergency operations (including but not limited to medical evacuations, weather-related evacuations and emergency shutdown operations);

(4) Normal shutdown;

(5) Startup following a turnaround, or after an emergency shutdown;

(6) Bypassing and flagging out-of-service equipment;

(7) Safety and environmental consequences of deviating from your equipment operating limits and steps required to correct or avoid this deviation;

(8) Properties of, and hazards presented by, the chemicals used in the operations;

(9) Precautions you will take to prevent the exposure of chemicals used in your operations to personnel and the environment. The precautions must include control technology, personal protective equipment, and measures to be taken if physical contact or airborne exposure occurs;

(10) Raw materials used in your operations and the quality control procedures you used in purchasing these raw materials;

(11) Control of hazardous chemical inventory; and

(12) Impacts to the human and marine environment identified through your hazards analysis.

(b) Operating procedures must be accessible to all employees involved in the operations.

(c) Operating procedures must be reviewed at the conclusion of specified periods and as often as necessary to assure they reflect current and actual operating practices, including any changes made to your operations.

(d) You must develop and implement safe and environmentally sound work practices for identified hazards during operations and the degree of hazard presented.

(e) Review of and changes to the procedures must be documented and communicated to responsible personnel.

Back to Top

§250.1914 What criteria must be documented in my SEMS program for safe work practices and contractor selection?

Your SEMS program must establish and implement safe work practices designed to minimize the risks associated with operations, maintenance, modification activities, and the handling of materials and substances that could affect safety or the environment. Your SEMS program must also document contractor selection criteria. When selecting a contractor, you must obtain and evaluate information regarding the contractor's safety record and environmental performance. You must ensure that contractors have their own written safe work practices. Contractors may adopt appropriate sections of your SEMS program. You and your contractor must document an agreement on appropriate contractor safety and environmental policies and practices before the contractor begins work at your facilities.

(a) A contractor is anyone performing work for you. However, these requirements do not apply to contractors providing domestic services to you or other contractors. Domestic services include janitorial work, food and beverage service, laundry service, housekeeping, and similar activities.

(b) You must document that your contracted employees are knowledgeable and experienced in the work practices necessary to perform their job in a safe and environmentally sound manner. Documentation of each contracted employee's expertise to perform his/her job and a copy of the contractor's safety policies and procedures must be made available to the operator and BSEE upon request.

(c) Your SEMS program must include procedures and verification for selecting a contractor as follows:

(1) Your SEMS program must have procedures that verify that contractors are conducting their activities in accordance with your SEMS program.

(2) You are responsible for making certain that contractors have the skills and knowledge to perform their assigned duties and are conducting these activities in accordance with the requirements in your SEMS program.

(3) You must make the results of your verification for selecting contractors available to BSEE upon request.

(d) Your SEMS program must include procedures and verification that contractor personnel understand and can perform their assigned duties for activities such as, but not limited to:

(1) Installation, maintenance, or repair of equipment;

(2) Construction, startup, and operation of your facilities;

(3) Turnaround operations;

(4) Major renovation; or

(5) Specialty work.

(e) You must:

(1) Perform periodic evaluations of the performance of contract employees that verifies they are fulfilling their obligations, and

(2) Maintain a contractor employee injury and illness log for 2 years related to the contractor's work in the operation area, and include this information on Form BSEE-0131.

(f) You must inform your contractors of any known hazards at the facility they are working on including, but not limited to fires, explosions, slips, trips, falls, other injuries, and hazards associated with lifting operations.

(g) You must develop and implement safe work practices to control the presence, entrance, and exit of contract employees in operation areas.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

Back to Top

§250.1915 What training criteria must be in my SEMS program?

Your SEMS program must establish and implement a training program so that all personnel are trained in accordance with their duties and responsibilities to work safely and are aware of potential environmental impacts. Training must address such areas as operating procedures (§250.1913), safe work practices (§250.1914), emergency response and control measures (§250.1918), SWA (§250.1930), UWA (§250.1931), EPP (§250.1932), reporting unsafe working conditions (§250.1933), and how to recognize and identify hazards and how to construct and implement JSAs (§250.1911). You must document your instructors' qualifications. Your SEMS program must address:

(a) Initial training for the basic well-being of personnel and protection of the environment, and ensure that persons assigned to operate and maintain the facility possess the required knowledge and skills to carry out their duties and responsibilities, including startup and shutdown.

(b) Periodic training to maintain understanding of, and adherence to, the current operating procedures, using periodic drills, to verify adequate retention of the required knowledge and skills.

(c) Communication requirements to ensure that personnel will be informed of and trained as outlined in this section whenever a change is made in any of the areas in your SEMS program that impacts their ability to properly understand and perform their duties and responsibilities. Training and/or notice of the change must be given before personnel are expected to operate the facility.

(d) How you will verify that the contractors are trained in the work practices necessary to understand and perform their jobs in a safe and environmentally sound manner in accordance with all provisions of this section.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20441, Apr. 5, 2013]

Back to Top

§250.1916 What criteria for mechanical integrity must my SEMS program meet?

You must develop and implement written procedures that provide instructions to ensure the mechanical integrity and safe operation of equipment through inspection, testing, and quality assurance. The purpose of mechanical integrity is to ensure that equipment is fit for service. Your mechanical integrity program must encompass all equipment and systems used to prevent or mitigate uncontrolled releases of hydrocarbons, toxic substances, or other materials that may cause environmental or safety consequences. These procedures must address the following:

(a) The design, procurement, fabrication, installation, calibration, and maintenance of your equipment and systems in accordance with the manufacturer's design and material specifications.

(b) The training of each employee involved in maintaining your equipment and systems so that your employees can implement your mechanical integrity program.

(c) The frequency of inspections and tests of your equipment and systems. The frequency of inspections and tests must be in accordance with BSEE regulations and meet the manufacturer's recommendations. Inspections and tests can be performed more frequently if determined to be necessary by prior operating experience.

(d) The documentation of each inspection and test that has been performed on your equipment and systems. This documentation must identify the date of the inspection or test; include the name and position, and the signature of the person who performed the inspection or test; include the serial number or other identifier of the equipment on which the inspection or test was performed; include a description of the inspection or test performed; and the results of the inspection test.

(e) The correction of deficiencies associated with equipment and systems that are outside the manufacturer's recommended limits. Such corrections must be made before further use of the equipment and system.

(f) The installation of new equipment and constructing systems. The procedures must address the application for which they will be used.

(g) The modification of existing equipment and systems. The procedures must ensure that they are modified for the application for which they will be used.

(h) The verification that inspections and tests are being performed. The procedures must be appropriate to ensure that equipment and systems are installed consistent with design specifications and the manufacturer's instructions.

(i) The assurance that maintenance materials, spare parts, and equipment are suitable for the applications for which they will be used.

Back to Top

§250.1917 What criteria for pre-startup review must be in my SEMS program?

Your SEMS program must require that the commissioning process include a pre-startup safety and environmental review for new and significantly modified facilities that are subject to this subpart to confirm that the following criteria are met:

(a) Construction and equipment are in accordance with applicable specifications.

(b) Safety, environmental, operating, maintenance, and emergency procedures are in place and are adequate.

(c) Safety and environmental information is current.

(d) Hazards analysis recommendations have been implemented as appropriate.

(e) Training of operating personnel has been completed.

(f) Programs to address management of change and other elements of this subpart are in place.

(g) Safe work practices are in place.

Back to Top

§250.1918 What criteria for emergency response and control must be in my SEMS program?

Your SEMS program must require that emergency response and control plans are in place and are ready for immediate implementation. These plans must be validated by drills carried out in accordance with a schedule defined by the SEMS training program (§250.1915). The SEMS emergency response and control plans must include:

(a) Emergency Action Plan that assigns authority and responsibility to the appropriate qualified person(s) at a facility for initiating effective emergency response and control, addressing emergency reporting and response requirements, and complying with all applicable governmental regulations;

(b) Emergency Control Center(s) designated for each facility with access to the Emergency Action Plans, oil spill contingency plan, and other safety and environmental information (§250.1910); and

(c) Training and Drills incorporating emergency response and evacuation procedures conducted periodically for all personnel (including contractor's personnel), as required by the SEMS training program (§250.1915). Drills must be based on realistic scenarios conducted periodically to exercise elements contained in the facility or area emergency action plan. An analysis and critique of each drill must be conducted to identify and correct weaknesses.

Back to Top

§250.1919 What criteria for investigation of incidents must be in my SEMS program?

To learn from incidents and help prevent similar incidents, your SEMS program must establish procedures for investigation of all incidents with serious safety or environmental consequences and require investigation of incidents that are determined by facility management or BSEE to have possessed the potential for serious safety or environmental consequences. Incident investigations must be initiated as promptly as possible, with due regard for the necessity of securing the incident scene and protecting people and the environment. Incident investigations must be conducted by personnel knowledgeable in the process involved, investigation techniques, and other specialties that are relevant or necessary.

(a) The investigation of an incident must address the following:

(1) The nature of the incident;

(2) The factors (human or other) that contributed to the initiation of the incident and its escalation/control; and

(3) Recommended changes identified as a result of the investigation.

(b) A corrective action program must be established based on the findings of the investigation in order to analyze incidents for common root causes. The corrective action program must:

(1) Retain the findings of investigations for use in the next hazard analysis update or audit;

(2) Determine and document the response to each finding to ensure that corrective actions are completed; and

(3) Implement a system whereby conclusions of investigations are distributed to similar facilities and appropriate personnel within their organization.

Back to Top

§250.1920 What are the auditing requirements for my SEMS program?

(a) Your SEMS program must be audited by an accredited ASP according to the requirements of this subpart and API RP 75, Section 12 (incorporated by reference as specified in §250.198). The audit process must also meet or exceed the criteria in Sections 9.1 through 9.8 of *Requirements for Third-party SEMS Auditing and Certification of Deepwater Operations* COS-2-03 (incorporated by reference as specified in §250.198) or its equivalent. Additionally, the audit team lead must be an employee, representative, or agent of the ASP, and must not have any affiliation with the operator. The remaining team members may be chosen from your personnel and those of the ASP. The audit must be comprehensive and include all elements of your SEMS program. It must also identify safety and environmental performance deficiencies.

(b) Your audit plan and procedures must meet or exceed all of the recommendations included in API RP 75 section 12 (as specified in §250.198) and include information on how you addressed those recommendations. You must specifically address the following items:

(1) Section 12.1 General.

(2) Section 12.2 Scope.

(3) Section 12.3 Audit Coverage.

(4) Section 12.4 Audit Plan. You must submit your written Audit Plan to BSEE at least 30 days before the audit. BSEE reserves the right to modify the list of facilities that you propose to audit.

(5) Section 12.5 Audit Frequency. You must have your SEMS program audited by an ASP within 2 years after initial implementation and every 3 years thereafter. The 3-year auditing cycle begins on the start date of each comprehensive audit (including the initial implementation audit) and ends on the start date of your next comprehensive

audit. For exploratory drilling operations taking place on the Arctic OCS, you must conduct an audit, consisting of an onshore portion and an offshore portion, including all related infrastructure, once per year for every year in which drilling is conducted.

(6) Section 12.6 Audit Team. Your audits must be performed by an ASP as described in §250.1921. You must include the ASP's qualifications in your audit plan.

(c) You must submit an audit report of the audit findings, observations, deficiencies identified, and conclusions to BSEE within 60 days of the audit completion date. For exploratory drilling operations taking place on the Arctic OCS, you must submit an audit report of the audit findings, observations, deficiencies and conclusions for the onshore portion of your audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(d) You must provide BSEE with a copy of your CAP for addressing the deficiencies identified in your audit within 60 days of the audit completion date. Your CAP must include the name and job title of the personnel responsible for correcting the identified deficiency(ies). The BSEE will notify you as soon as practicable after receipt of your CAP if your proposed schedule is not acceptable or if the CAP does not effectively address the audit findings. For exploratory drilling operations taking place on the Arctic OCS, you must provide BSEE with a copy of your CAP for addressing deficiencies or nonconformities identified in the onshore portion of the audit no later than March 1 in any year in which you plan to drill, and for the offshore portion of your audit, within 30 days of the close of the audit.

(e) BSEE may verify that you undertook the corrective actions and that these actions effectively address the audit findings.

(f) For exploratory drilling operations taking place on the Arctic OCS, during the offshore portion of each audit, 100 percent of the facilities operated must be audited while drilling activities are underway. You must start and close the offshore portion of the audit for each facility within 30 days after the first spudding of the well or entry into an existing wellbore for any purpose from that facility.

(g) For exploratory drilling operations taking place on the Arctic OCS, if BSEE determines that the CAP or progress toward implementing the CAP is not satisfactory, BSEE may order you to shut down all or part of your operations.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013; 81 FR 36151, June 6, 2016; 81 FR 46563, July 15, 2016]

Back to Top

§250.1921 What qualifications must the ASP meet?

(a) The ASP must meet or exceed the qualifications, competency, and training criteria contained in Section 3 and Sections 6 through 10 of *Qualification and Competence Requirements for Audit Teams and Auditors Performing Third-party SEMS Audits of Deepwater Operations,* COS-2-01, (incorporated by reference as specified in §250.198) or its equivalent;

(b) The ASP must be accredited by a BSEE-approved AB; and

(c) The ASP must perform an audit in accordance with 250.1920(a).

[78 FR 20442, Apr. 5, 2013]

Back to Top

§250.1922 What qualifications must an AB meet?

(a) In order for BSEE to approve an AB, the organization must satisfy the requirements of the International Organization for Standardization's (ISO/IEC 17011) *Conformity assessment—General requirements for accreditation bodies accrediting conformity assessment bodies,* First Edition 2004-09-01; Corrected Version 2005-02-15 (incorporated by reference as specified in §250.198) or its equivalent.

(1) The AB must have an accreditation process that meets or exceeds the requirements contained in Section 6 of *Requirements for Accreditation of Audit Service Providers Performing SEMS Audits and Certification of Deepwater Operations,* COS-2-04 (incorporated by reference as specified in §250.198) or its equivalent, and other requirements specified in this subpart. Organizations requesting approval must submit documentation to BSEE describing the process for assessing an ASP for accreditation and approving, maintaining, and withdrawing the accreditation of an ASP. Requests for approval must be sent to DOI/BSEE, ATTN: Chief, Office of Offshore Regulatory Programs, 381 Elden Street, HE-3314, Herndon, VA 20170.

(2) An AB may be subject to BSEE audits and other requirements deemed necessary to verify compliance with the accreditation requirements.

(b) An AB must have procedures in place to avoid conflicts of interest with the ASP and make such information available to BSEE upon request.

[78 FR 20442, Apr. 5, 2013]

Back to Top

§250.1923 [Reserved]

Back to Top

§250.1924 How will BSEE determine if my SEMS program is effective?

(a) The BSEE, or its authorized representative, may evaluate or visit your facility(ies) to determine whether your SEMS program is in place, addresses all required elements, is effective in protecting worker safety and health and the environment, and preventing incidents. The BSEE, or its authorized representative, may evaluate any and all aspects of your SEMS program as outlined in this subpart. These evaluations or visits may be random and may be based upon your performance or that of your contractors.

(b) For the evaluations, you must make the following available to BSEE upon request:

(1) Your SEMS program;

(2) Your audit team's qualifications;

(3) The SEMS audits conducted of your program;

(4) Documents or information relevant to whether you have addressed and corrected the deficiencies of your audit; and

(5) Other relevant documents or information.

(c) During the site visit BSEE may verify that:

(1) Personnel are following your SEMS program,

(2) You can explain and demonstrate the procedures and policies included in your SEMS program; and

(3) You can produce evidence to support the implementation of your SEMS program.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013]

Back to Top

§250.1925 May BSEE direct me to conduct additional audits?

(a) The BSEE may direct you to have an ASP audit of your SEMS program if BSEE identifies safety or non-compliance concerns based on the results of our inspections and evaluations, or as a result of an event. This BSEE-directed audit is in addition to the regular audit required by §250.1920. Alternatively, BSEE may conduct an audit.

(1) If BSEE directs you to have an ASP audit, you are responsible for all of the costs associated with the audit, and

(i) The ASP must meet the requirements of §§250.1920 and 250.1921 of this subpart.

(ii) You must submit an audit report of the audit findings, observations, deficiencies identified, and conclusions to BSEE within 60 days of the audit completion date.

(2) If BSEE conducts the audit, BSEE will provide you with a report of the audit findings, observations, deficiencies identified, and conclusions as soon as practicable.

(b) You must provide BSEE a copy of your CAP for addressing the deficiencies identified in the BSEE-directed audit within 60 days of the audit completion date. Your CAP must include the name and job title of the personnel responsible for correcting the identified deficiency(ies). The BSEE will notify you as soon as practicable after receipt of your CAP if your proposed schedule is not acceptable or if the CAP does not effectively address the audit findings.

[78 FR 20442, Apr. 5, 2013]

Back to Top

§250.1926 [Reserved]

Back to Top

§250.1927 What happens if BSEE finds shortcomings in my SEMS program?

If BSEE determines that your SEMS program is not in compliance with this subpart we may initiate one or more of the following enforcement actions:

(a) Issue an Incident(s) of Noncompliance;

(b) Assess civil penalties; or

(c) Initiate probationary or disqualification procedures from serving as an OCS operator.

Back to Top

§250.1928 What are my recordkeeping and documentation requirements?

(a) Your SEMS program procedures must ensure that records and documents are maintained for a period of 6 years, except as provided below. You must document and keep all SEMS audits for 6 years and make them available to BSEE upon request. You must maintain a copy of all SEMS program documents at an onshore location.

(b) For JSAs, the person in charge of the job must document the results of the JSA in writing and must ensure that records are kept onsite for 30 days. In the case of a MODU, records must be kept onsite for 30 days or until you release the MODU, whichever comes first. You must retain these records for 2 years and make them available to BSEE upon request.

(c) You must document and date all management of change provisions as specified in §250.1912. You must retain these records for 2 years and make them available to BSEE upon request.

(d) You must keep your injury/illness log for 2 years and make them available to BSEE upon request.

(e) You must keep all evaluations completed on contractor's safety policies and procedures for 2 years and make them available to BSEE upon request.

(f) For SWA, you must document all training and reviews required by §250.1930(e). You must ensure that these records are kept onsite for 30 days. In the case of a MODU, records must be kept onsite for 30 days or until you release the MODU, whichever comes first. You must retain these records for 2 years and make them available to BSEE upon request.

(g) For EPP, you must document your employees' participation in the development and implementation of the SEMS program. You must retain these records for 2 years and make them available to BSEE upon request.

(h) You must keep all records in an orderly manner, readily identifiable, retrievable and legible, and include the date of any and all revisions.

[76 FR 64462, Oct. 18, 2011, as amended at 78 FR 20442, Apr. 5, 2013]

Back to Top

§250.1929 What are my responsibilities for submitting OCS performance measure data?

You must submit Form BSEE-0131 on an annual basis by March 31st. The form must be broken down quarterly, reporting the previous calendar year's data.

Back to Top

§250.1930 What must be included in my SEMS program for SWA?

(a) Your SWA procedures must ensure the capability to immediately stop work that is creating imminent risk or danger. These procedures must grant all personnel the responsibility and authority, without fear of reprisal, to stop work or decline to perform an assigned task when an imminent risk or danger exists. Imminent risk or danger means any condition, activity, or practice in the workplace that could reasonably be expected to cause:

(1) Death or serious physical harm; or

(2) Significant environmental harm to:

(i) Land;

(ii) Air; or

(iii) Mineral deposits, marine, coastal, or human environment.

(b) The person in charge of the conducted work is responsible for ensuring the work is stopped in an orderly and safe manner. Individuals who receive a notification to stop work must comply with that direction immediately.

(c) Work may be resumed when the individual on the facility with UWA determines that the imminent risk or danger does not exist or no longer exists. The decision to resume activities must be documented in writing as soon as practicable.

(d) You must include SWA procedures and expectations as a standard statement in all JSAs.

(e) You must conduct training on your SWA procedures as part of orientations for all new personnel who perform activities on the OCS. Additionally, the SWA procedures must be reviewed during all meetings focusing on safety on facilities subject to this subpart.

[78 FR 20443, Apr. 5, 2013]

Back to Top

§250.1931 What must be included in my SEMS program for UWA?

(a) Your SEMS program must have a process to identify the individual with the UWA on your facility(ies). You must designate this individual taking into account all applicable USCG regulations that deal with designating a person in charge of an OCS facility. Your SEMS program must clearly define who is in charge at all times. In the event that multiple facilities, including a MODU, are attached and working together or in close proximity to one another to perform an OCS operation, your SEMS program must identify the individual with the UWA over the entire operation, including all facilities.

(b) You must ensure that all personnel clearly know who has UWA and who is in charge of a specific operation or activity at all times, including when that responsibility shifts to a different individual.

(c) The SEMS program must provide that if an emergency occurs that creates an imminent risk or danger to the health or safety of an individual, the public, or to the environment (as specified in §250.1930(a)), the individual with the UWA is authorized to pursue the most effective action necessary in that individual's judgment for mitigating and abating the conditions or practices causing the emergency.

[78 FR 20443, Apr. 5, 2013]

Back to Top

§250.1932 What are my EPP requirements?

(a) Your management must consult with their employees on the development, implementation, and modification of your SEMS program.

(b) Your management must develop a written plan of action regarding how your appropriate employees, in both your offices and those working on offshore facilities, will participate in your SEMS program development and implementation.

(c) Your management must ensure that employees have access to sections of your SEMS program that are relevant to their jobs.

[78 FR 20443, Apr. 5, 2013]

Back to Top

§250.1933 What procedures must be included for reporting unsafe working conditions?

(a) Your SEMS program must include procedures for all personnel to report unsafe working conditions in accordance with §250.193. These procedures must take into account applicable USCG reporting requirements for unsafe working conditions.

(b) You must post a notice at the place of employment in a visible location frequently visited by personnel that contains the reporting information in §250.193.

[78 FR 20443, Apr. 5, 2013]

Back to Top

Need assistance?