Title 30: Mineral Resources

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

Subpart D—Oil and Gas Drilling Operations

General Requirements

§ 250.400   Who is subject to the requirements of this subpart?

The requirements of this subpart apply to lessees, operating rights owners, operators, and their contractors and subcontractors.

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

You must take necessary precautions to keep wells under control at all times. You must:

(a) Use the best available and safest drilling technology to monitor and evaluate well conditions and to minimize the potential for the well to flow or kick;

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

(c) Ensure that the toolpusher, operator's representative, or a member of the drilling crew maintains continuous surveillance on the rig floor from the beginning of drilling operations until the well is completed or abandoned, unless you have secured the well with blowout preventers (BOPs), bridge plugs, cement plugs, or packers;

(d) Use personnel trained according to the provisions of subpart O; and

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

§ 250.402   When and how must I secure a well?

Whenever you interrupt drilling operations, you must install a downhole safety device, such as a cement plug, bridge plug, or packer. You must install the device at an appropriate depth within a properly cemented casing string or liner.

(a) Among the events that may cause you to interrupt drilling operations are:

(1) Evacuation of the drilling crew;

(2) Inability to keep the drilling rig on location; or

(3) Repair to major drilling or well-control equipment.

(b) For floating drilling operations, the District Manager may approve the use of blind or blind-shear rams or pipe rams and an inside BOP if you don't have time to install a downhole safety device or if special circumstances occur.

§ 250.403 What drilling unit movements must I report?

(a) You must report the movement of all drilling units on and off drilling locations to the District Manager. This includes both MODU and platform rigs. You must inform the District Manager 24 hours before:

(1) The arrival of an MODU on location;

(2) The movement of a platform rig to a platform;

(3) The movement of a platform rig to another slot;

(4) The movement of an MODU to another slot; and

(5) The departure of an MODU from the location.

(b) You must provide the District Manager with the rig name, lease number, well number, and expected time of arrival or departure.

(c) In the Gulf of Mexico OCS Region, you must report drilling unit movements on form BSEE–0144, Rig Movement Notification Report.

§ 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.

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

You must equip each diesel engine with an air take device to shut down the diesel engine in the event of a runaway.

(a) For a diesel engine that is not continuously manned, you must equip the engine with an automatic shutdown device;

(b) For a diesel engine that is continuously manned, you may equip the engine with either an automatic or remote manual air intake shutdown device;

(c) You do not have to equip a diesel engine with an air intake device if it meets one of the following criteria:

(1) Starts a larger engine;

(2) Powers a firewater pump;

(3) Powers an emergency generator;

(4) Powers a BOP accumulator system;

(5) Provides air supply to divers or confined entry personnel;

(6) Powers temporary equipment on a nonproducing platform;

(7) Powers an escape capsule; or

(8) Powers a portable single-cylinder rig washer.

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

You must take the following safety measures when you conduct drilling operations on a platform with producing wells or that has other hydrocarbon flow:

(a) You must install an emergency shutdown station near the driller's console;

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

(1) You move a drilling rig or related equipment on and off a platform. This includes rigging up and rigging down activities within 500 feet of the affected platform;

(2) You move or skid a drilling unit between wells on a platform;

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

§ 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.

§ 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.

§ 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)).

Applying for a Permit To Drill

§ 250.410 How do I obtain approval to drill a well?

You must obtain written approval from the District Manager before you begin drilling any well or before you sidetrack, bypass, or deepen a well. To obtain approval, you must:

(a) Submit the information required by §§250.411 through 250.418;

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

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

§ 250.411   What information must I submit with my application?

In addition to forms BSEE–0123 and BSEE–0123S, you must include the information described in the following table.

Information that you must

include with an APD Where to find a description

(a) Plat that shows locations of the proposed well §250.412

(b) Design criteria used for the proposed well §250.413

(c) Drilling prognosis §250.414

(d) Casing and cementing programs §250.415

(e) Diverter and BOP systems descriptions §250.416

(f) Requirements for using an MODU §250.417

(g) Additional information §250.418

§ 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.

§ 250.413   What must my description of well drilling design criteria address?

Your description of well drilling design criteria must address:

(a) Pore pressures;

(b) Formation fracture gradients, adjusted for water depth;

(c) Potential lost circulation zones;

(d) Drilling fluid weights;

(e) Casing setting depths;

(f) Maximum anticipated surface pressures. For this section, maximum anticipated surface pressures are the pressures that you reasonably expect to be exerted upon a casing string and its related wellhead equipment. In calculating maximum anticipated surface pressures, you must consider: drilling, completion, and producing conditions; drilling fluid densities to be used below various casing strings; fracture gradients of the exposed formations; casing setting depths; total well depth; formation fluid types; safety margins; and other pertinent conditions. You must include the calculations used to determine the pressures for the drilling and the completion phases, including the anticipated surface pressure used for designing the production string;

(g) A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, and casing setting depths in true vertical measurements;

(h) A summary report of the shallow hazards site survey that describes the geological and manmade conditions if not previously submitted; and

(i) Permafrost zones, if applicable.

§ 250.414 What must my drilling prognosis include?

Your drilling prognosis must include a brief description of the procedures you will follow in drilling the well. This prognosis includes but is not limited to the following:

(a) Projected plans for coring at specified depths;

(b) Projected plans for logging;

(c) Planned safe drilling margin between proposed drilling fluid weights and estimated pore pressures. This safe drilling margin may be shown on the plot required by §250.413(g);

(d) Estimated depths to the top of significant marker formations;

(e) Estimated depths to significant porous and permeable zones containing fresh water, oil, gas, or abnormally pressured formation fluids;

(f) Estimated depths to major faults;

(g) Estimated depths of permafrost, if applicable;

(h) A list and description of all requests for using alternative procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternative procedures afford an equal or greater degree of protection, safety, or performance, or why you need the departures; and

(i) Projected plans for well testing (refer to §250.460 for safety requirements).

§ 250.415 What must my casing and cementing programs include?

Your casing and cementing programs must include:

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

(b) Casing design safety factors for tension, collapse, and burst with the assumptions made to arrive at these values;

(c) Type and amount of cement (in cubic feet) planned for each casing string;

(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 RP 65–Part 2, Isolating Potential Flow Zones During Well Construction (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 RP 65–Part 2, Sections 3 and 4).

§ 250.416   What must I include in the diverter and BOP descriptions?

You must include in the diverter and BOP descriptions:

(a) A description of the diverter system and its operating procedures;

(b) A schematic drawing of the diverter system (plan and elevation views) that shows:

(1) The size of the annular BOP installed in the diverter housing;

(2) Spool outlet internal diameter(s);

(3) Diverter-line lengths and diameters; burst strengths and radius of curvature at each turn; and

(4) Valve type, size, working pressure rating, and location;

(c) A description of the BOP system and system components, including pressure ratings of BOP equipment and proposed BOP test pressures;

(d) A schematic drawing of the BOP system that shows the inside diameter of the BOP stack, number and type of preventers, all control systems and pods, location of choke and kill lines, and associated valves;

(e) Independent third party verification and supporting documentation that show the blind-shear rams installed in the BOP stack are capable of shearing any drill pipe in the hole under maximum anticipated surface pressure. The documentation must include test results and calculations of shearing capacity of all pipe to be used in the well including correction for MASP;

(f) When you use a subsea BOP stack, independent third party verification that shows:

(1) The BOP stack is designed for the specific equipment on the rig and for the specific well design;

(2) The BOP stack has not been compromised or damaged from previous service;

(3) The BOP stack will operate in the conditions in which it will be used; and

(g) The qualifications of the independent third party referenced in paragraphs (e) and (f) of this section:

(1) The independent third party in paragraph (e) in this section must be a technical classification society; an API-licensed manufacturing, inspection, or certification firm; or a licensed professional engineering firm capable of providing the verifications required under this part. The independent third party must not be the original equipment manufacturer (OEM).

(2) You must:

(i) Include evidence that the firm you are using is reputable, the firm or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, the firm carries industry-standard levels of professional liability insurance, and the firm has no record of violations of applicable law.

(ii) Ensure that an official representative of BSEE will have access to the location to witness any testing or inspections, and verify information submitted to BSEE. Prior to any shearing ram tests or inspections, you must notify the District Manager at least 24 hours in advance.

§ 250.417 What must I provide if I plan to use a mobile offshore drilling unit (MODU)?

If you plan to use a MODU, you must provide:

(a) Fitness requirements. You must provide information and data to demonstrate the drilling unit's capability to perform at the proposed drilling location. This information must include the maximum environmental and operational conditions that the unit is designed to withstand, including the minimum air gap necessary for both hurricane and non-hurricane seasons. If sufficient environmental information and data are not available at the time you submit your APD, the District Manager may approve your APD but require you to collect and report this information during operations. Under this circumstance, the District Manager has the right to revoke the approval of the APD if information collected during operations show that the drilling unit is not capable of performing at the proposed location.

(b) Foundation requirements. You must provide information to show that site-specific soil and oceanographic conditions are capable of supporting the proposed drilling unit. If you provided sufficient site-specific information in your EP, DPP, or DOCD submitted to BOEM, you may reference that information. The District Manager may require you to conduct additional surveys and soil borings before approving the APD if additional information is needed to make a determination that the conditions are capable of supporting the drilling unit.

(c) Frontier areas. (1) If the design of the drilling unit you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the unit's design. If required, you must obtain the third-party review according to §§250.915 through 250.918. You may submit this information before submitting an APD.

(2) If you plan to drill in a frontier area, you must have a contingency plan that addresses design and operating limitations of the drilling unit. Your plan must identify the actions necessary to maintain safety and prevent damage to the environment. Actions must include the suspension, curtailment, or modification of drilling or rig operations to remedy various operational or environmental situations (e.g., vessel motion, riser offset, anchor tensions, wind speed, wave height, currents, icing or ice-loading, settling, tilt or lateral movement, resupply capability).

(d) U.S. Coast Guard (USCG) documentation. You must provide the current Certificate of Inspection or Letter of Compliance from the USCG. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

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

(f) Inspection of unit. The drilling unit must be available for inspection by the District Manager before commencing operations.

(g) Once the District Manager has approved a MODU for use, you do not need to re-submit the information required by this section for another APD to use the same MODU unless changes in equipment affect its rated capacity to operate in the District.

§ 250.418 What additional information must I submit with my APD?

You must include the following with the APD:

(a) Rated capacities of the drilling rig and major drilling equipment, if not already on file with the appropriate District office;

(b) A drilling fluids program that includes the minimum quantities of drilling fluids and drilling fluid materials, including weight materials, to be kept at the site;

(c) A proposed directional plot if the well is to be directionally drilled;

(d) A Hydrogen Sulfide Contingency Plan (see §250.490), if applicable, and not previously submitted;

(e) A welding plan (see §§250.109 to 250.113) if not previously submitted;

(f) In areas subject to subfreezing conditions, evidence that the drilling equipment, BOP systems and components, diverter systems, and other associated equipment and materials are suitable for operating under such conditions;

(g) A request for approval if you plan to wash out or displace some cement to facilitate casing removal upon well abandonment;

(h) Certification of your casing and cementing program as required in §250.420(a)(6);

(i) Description of qualifications required by §250.416(f) of any independent third party; and

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

Casing and Cementing Requirements

§ 250.420 What well casing and cementing requirements must I meet?

You must case and cement all wells. Your casing and cementing programs must meet the requirements of this section and of §§250.421 through 250.428.

(a) 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; and

(6) Include certification signed by a Registered Professional Engineer that there will be at least two independent tested barriers, including one mechanical barrier, across each flow path during well completion activities and that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions. The Registered Professional Engineer must be registered in a State in the United States. Submit this certification with your APD (Form BSEE–0123).

(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) For the final casing string (or liner if it is your final string), you must install dual mechanical barriers in addition to cement, to prevent flow in the event of a failure in the cement. These may include dual float valves, or one float valve and a mechanical barrier. You must submit documentation to BSEE 30 days after installation of the dual mechanical barriers.

(c) Cementing requirements. You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out of the casing or before commencing completion operations.

§ 250.421 What are the casing and cementing requirements by type of casing string?

The table in this section identifies specific design, setting, and cementing requirements for casing strings and liners. For the purposes of subpart D, the casing strings in order of normal installation are as follows: drive or structural, conductor, surface, intermediate, and production casings (including liners). The District Manager may approve or prescribe other casing and cementing requirements where appropriate.

Casing type Casing requirements Cementing requirements

(a) Drive or Structural Set by driving, jetting, or drilling to the minimum depth as approved or prescribed by the District Manager If you drilled a portion of this hole, you must use enough cement to fill the annular space back to the mudline.

(b) Conductor Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths;

Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately Use enough cement to fill the calculated annular space back to the mudline.

Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline.

For drilling on an artificial island or when using a glory hole, you must discuss the cement fill level with the District Manager.

(c) Surface Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths Use enough cement to fill the calculated annular space to at least 200 feet inside the conductor casing.

When geologic conditions such as near-surface fractures and faulting exist, you must use enough cement to fill the calculated annular space to the mudline.

(d) Intermediate Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions Use enough cement to cover and isolate all hydrocarbon-bearing zones and isolate abnormal pressure intervals from normal pressure intervals in the well.

As a minimum, you must cement the annular space 500 feet above the casing shoe and 500 feet above each zone to be isolated.

(e) Production Design casing and select setting depth based on anticipated or encountered geologic characteristics or wellbore conditions Use enough cement to cover or isolate all hydrocarbon-bearing zones above the shoe.

As a minimum, you must cement the annular space at least 500 feet above the casing shoe and 500 feet above the uppermost hydrocarbon-bearing zone.

(f) Liners If you use a liner as conductor or surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe

If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe

Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing.

§ 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.

§ 250.423   What are the requirements for pressure testing casing?

(a) The table in this section describes the minimum test pressures for each string of casing. You may not resume drilling or other down-hole operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must re-cement, repair the casing, or run additional casing to provide a proper seal. The District Manager may approve or require other casing test pressures.

Casing type Minimum test pressure

(1) Drive or Structural Not required.

(2) Conductor 200 psi.

(3) Surface, Intermediate, and Production 70 percent of its minimum internal yield.

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

(1) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon installation of each casing string or liner.

(2) 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 liner.

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

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

(c) You must perform a negative pressure test on all wells to ensure proper casing installation. You must perform this test for the intermediate and production casing strings.

(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.

§ 250.424 What are the requirements for prolonged drilling operations?

If wellbore operations continue for more than 30 days within a casing string run to the surface:

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

(1) Caliper or pressure test the casing; and

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations.

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

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

(2) Obtain approval from the District Manager before you begin repairs.

§ 250.425 What are the requirements for pressure testing liners?

(a) You must test each drilling liner (and liner-lap) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Manager may approve or require other liner test pressures.

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

(c) You may not resume drilling or other down-hole operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test or if there is another indication of a leak, you must re-cement, repair the liner, or run additional casing/liner to provide a proper seal.

§ 250.426 What are the recordkeeping requirements for casing and liner pressure tests?

You must record the time, date, and results of each pressure test in the driller's report maintained under standard industry practice. In addition, you must record each test on a pressure chart and have your onsite representative sign and date the test as being correct.

§ 250.427 What are the requirements for pressure integrity tests?

You must conduct a pressure integrity test below the surface casing or liner and all intermediate casings or liners. The District Manager may require you to run a pressure-integrity test at the conductor casing shoe if warranted by local geologic conditions or the planned casing setting depth. You must conduct each pressure integrity test after drilling at least 10 feet but no more than 50 feet of new hole below the casing shoe. You must test to either the formation leak-off pressure or to an equivalent drilling fluid weight if identified in an approved APD.

(a) You must use the pressure integrity test and related hole-behavior observations, such as pore-pressure test results, gas-cut drilling fluid, and well kicks to adjust the drilling fluid program and the setting depth of the next casing string. You must record all test results and hole-behavior observations made during the course of drilling related to formation integrity and pore pressure in the driller's report.

(b) While drilling, you must maintain the safe drilling margin identified in the approved APD. When you cannot maintain this safe margin, you must suspend drilling operations and remedy the situation.

§ 250.428 What must I do in certain cementing and casing situations?

The table in this section describes actions that lessees must take when certain situations occur during casing and cementing activities.

If you encounter the following situation: Then you must . . .

(a) Have unexpected formation pressures or conditions that warrant revising your casing design, Submit a revised casing program to the District Manager for approval.

(b) Need to increase casing setting depths more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations, Submit those changes to the District Manager for approval.

(c) Have indication of inadequate cement job (such as lost returns, cement channeling, or failure of equipment), (1) Pressure test the casing shoe; (2) Run a temperature survey; (3) Run a cement bond log; or (4) Use a combination of these techniques.

(d) Inadequate cement job, Re-cement or take other remedial actions as approved by the District Manager.

(e) Primary cement job that did not isolate abnormal pressure intervals, Isolate those intervals from normal pressures by squeeze cementing before you complete; suspend operations; or abandon the well, whichever occurs first.

(f) Decide to produce a well that was not originally contemplated for production, Have at least two cemented casing strings (does not include liners) in the well. Note: All producing wells must have at least two cemented casing strings.

(g) Want to drill a well without setting conductor casing, Submit geologic data and information to the District Manager that demonstrates the absence of shallow hydrocarbons or hazards. This information must include logging and drilling fluid-monitoring from wells previously drilled within 500 feet of the proposed well path down to the next casing point.

(h) Need to use less than required cement for the surface casing during floating drilling operations to provide protection from burst and collapse pressures, Submit information to the District Manager that demonstrates the use of less cement is necessary.

(i) Cement across a permafrost zone, Use cement that sets before it freezes and has a low heat of hydration.

(j) Leave the annulus opposite a permafrost zone uncemented, Fill the annulus with a liquid that has a freezing point below the minimum permafrost temperature and minimizes opposite a corrosion.

Diverter System Requirements

§ 250.430   When must I install a diverter system?

You must install a diverter system before you drill a conductor or surface hole. The diverter system consists of a diverter sealing element, diverter lines, and control systems. You must design, install, use, maintain, and test the diverter system to ensure proper diversion of gases, water, drilling fluid, and other materials away from facilities and personnel.

§ 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.

§ 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.

§ 250.433 What are the diverter actuation and testing requirements?

When you install the diverter system, you must actuate the diverter sealing element, diverter valves, and diverter-control systems and control stations. You must also flow-test the vent lines.

(a) For drilling operations with a surface wellhead configuration, you must actuate the diverter system at least once every 24-hour period after the initial test. After you have nippled up on conductor casing, you must pressure-test the diverter-sealing element and diverter valves to a minimum of 200 psi. While the diverter is installed, you must conduct subsequent pressure tests within 7 days after the previous test.

(b) For floating drilling operations with a subsea BOP stack, you must actuate the diverter system within 7 days after the previous actuation.

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

§ 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.

Blowout Preventer (BOP) System Requirements

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

You must design, install, maintain, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed maximum anticipated surface pressures. The BOP system includes the BOP stack and associated BOP systems and equipment.

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

(a) When you drill with a surface BOP stack, you must install the BOP system before drilling below surface casing. The surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind or blind-shear rams.

(b) Your surface BOP stack must include at least four remote-controlled, hydraulically operated BOPs consisting of an annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing the drill pipe that is in the hole.

(c) You must install an accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components. The system must perform with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost.

(d) In addition to the stack and accumulator system, you must install the associated BOP systems and equipment required by the regulations in this subpart.

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

When you drill with a subsea BOP system, you must install the BOP system before drilling below the surface casing. The District Manager may require you to install a subsea BOP system before drilling below the conductor casing if proposed casing setting depths or local geology indicate the need. The table in this paragraph outlines your requirements.

When drilling with a subsea BOP system, you must: Additional requirements

(a) Have at least four remote-controlled, hydraulically operated BOPs You must have at least one annular BOP, two BOPs equipped with pipe rams, and one BOP equipped with blind-shear rams. The blind-shear rams must be capable of shearing any drill pipe in the hole under maximum anticipated surface pressures.

(b) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system

(c) Have an accumulator system to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface The accumulator system must meet or exceed the provisions of Section 13.3, Accumulator Volumetric Capacity, in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in §250.198). The District Manager may approve a suitable alternate method.

(d) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability At a minimum, the ROV must be capable of closing one set of pipe rams, closing one set of blind-shear rams and unlatching the LMRP.

(e) Maintain an ROV and have a trained ROV crew on each floating drilling rig on a continuous basis. The crew must examine all ROV related well control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well 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.

(f) Provide autoshear and deadman systems for dynamically positioned rigs (1) Autoshear system means a safety system that is designed to automatically shut in the wellbore in the event of a disconnect of the

LMRP. When the autoshear is armed, a disconnect of the LMRP closes the shear rams. This is considered a “rapid discharge” system.

(2) Deadman System means a safety system that is designed to automatically close 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.

(3) You may also have an acoustic system.

(g) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect functions Incorporate enable buttons on control panels to ensure two-handed operation for all critical functions.

(h) Clearly label all control panels for the subsea BOP system Label other BOP control panels such as hydraulic control panel.

(i) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(j) Establish minimum requirements for personnel authorized to operate critical BOP equipment Personnel must have:

(1) Training in deepwater well control theory and practice according to the requirements of 30 CFR 250, subpart O; and

(2) A comprehensive knowledge of BOP hardware and control systems.

(k) 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.

(l) Install the BOP stack in a glory hole when in ice-scour area Your glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

§ 250.443 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

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

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

(c) Side outlets on the BOP stack for separate kill and choke lines. If your stack does not have side outlets, you must install a drilling spool with side outlets.

(d) A choke and a kill line on the BOP stack. You must equip each line with two full-opening valves, one of which must be remote-controlled. For a subsea BOP system, both valves in each line must be remote-controlled. In addition:

(1) You must install the choke line above the bottom ram;

(2) You may install the kill line below the bottom ram; and

(3) For a surface BOP system, on the kill line you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

(e) A fill-up line above the uppermost BOP.

(f) Locking devices installed on the ram-type BOPs.

(g) A wellhead assembly with a rated working pressure that exceeds the maximum anticipated surface pressure.

§ 250.444 What are the choke manifold requirements?

(a) Your BOP system must include a choke manifold that is suitable for the anticipated surface pressures, anticipated methods of well control, the surrounding environment, and the corrosiveness, volume, and abrasiveness of drilling fluids and well fluids that you may encounter.

(b) Choke manifold components must have a rated working pressure at least as great as the rated working pressure of the ram BOPs. If your choke manifold has buffer tanks downstream of choke assemblies, you must install isolation valves on any bleed lines.

(c) Valves, pipes, flexible steel hoses, and other fittings upstream of the choke manifold must have a rated working pressure at least as great as the rated working pressure of the ram BOPs.

§ 250.445 What are the requirements for kelly valves, inside BOPs, and drill-string safety valves?

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

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

(b) A kelly valve installed at the bottom of the kelly (lower kelly valve). You must be able to strip the lower kelly valve through the BOP stack;

(c) If you drill with a mud motor and use drill pipe instead of a kelly, you must install one kelly valve above, and one strippable kelly valve below, the joint of drill pipe used in place of a kelly;

(d) On a top-drive system equipped with a remote-controlled valve, you must install a strippable kelly-type valve below the remote-controlled valve;

(e) An inside BOP in the open position located on the rig floor. You must be able to install an inside BOP for each size connection in the drill string;

(f) A drill-string safety valve in the open position located on the rig floor. You must have a drill-string safety valve available for each size connection in the drill string;

(g) When running casing, you must have a safety valve in the open position available on the rig floor to fit the casing string being run in the hole;

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

(i) The drilling crew must have ready access to a wrench to fit each manual valve.

§ 250.446   What are the BOP maintenance and inspection requirements?

(a) You must maintain and inspect your BOP system to ensure that the equipment functions properly. The BOP maintenance and inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections; Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (as incorporated by reference in §250.198). You must document the procedures used, record the results of your BOP inspections and maintenance actions, and make available to BSEE upon request. You must maintain your records on the rig for 2 years or from the date of your last major inspection, whichever is longer;

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

§ 250.447   When must I pressure test the BOP system?

You must pressure test your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill-string safety valve):

(a) When installed;

(b) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 14th day following the conclusion of the previous test. However, the District Manager may require more frequent testing if conditions or BOP performance warrant; and

(c) Before drilling out each string of casing or a liner. The District Manager may allow you to omit this test if you didn't remove the BOP stack to run the casing string or liner and the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test. You must indicate in your APD which casing strings and liners meet these criteria.

§ 250.448 What are the BOP pressure tests requirements?

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

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

(b) High-pressure test for ram-type BOPs, the choke manifold, and other BOP components. The high-pressure test must equal the rated working pressure of the equipment or be 500 psi greater than your calculated maximum anticipated surface pressure (MASP) for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.

(c) High pressure test for annular-type BOPs. The high pressure test must equal 70 percent of the rated working pressure of the equipment or to a pressure approved in your APD.

(d) Duration of pressure test. Each test must hold the required pressure for 5 minutes. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

§ 250.449 What additional BOP testing requirements must I meet?

You must meet the following additional BOP testing requirements:

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

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

(c) Alternate tests between control stations and pods;

(d) Pressure test the blind or blind-shear ram BOP during stump tests and at all casing points;

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

(f) Pressure test variable bore-pipe ram BOPs against the largest and smallest sizes of pipe in use, excluding drill collars and bottom-hole tools;

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

(h) Function test annular and ram BOPs every 7 days between pressure tests;

(i) Actuate safety valves assembled with proper casing connections before running casing;

(j) Test all ROV intervention functions on your subsea BOP stack during the stump test. You must also test at least one set of rams during the initial test on the seafloor. You must submit test procedures with your APD or APM for District Manager approval. You must:

(1) ensure that the ROV hot stabs are function tested and are capable of actuating, at a minimum, one set of pipe rams and one set of blind-shear rams and unlatching the LMRP; and

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

(k) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system during the initial test on the seafloor.

(1) You must submit test procedures with your APD or APM for District Manager approval.

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

§ 250.450   What are the recordkeeping requirements for BOP tests?

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

(a) Record BOP test pressures on pressure charts;

(b) Require your onsite representative to sign and date BOP test charts and reports as correct;

(c) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. For subsea BOP systems, you must also record the closing times for annular and ram BOPs. You may reference a BOP test plan if it is available at the facility;

(d) Identify the control station and pod used during the test;

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

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

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

The table in this section describes actions that lessees must take when certain situations occur with BOP systems during drilling activities.

If you encounter the following situation: Then you must . . .

(a) BOP equipment does not hold the required pressure during a test, Correct the problem and retest the affected equipment.

(b) Need to repair or replace a surface or subsea BOP system, First place the well in a safe, controlled condition (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer).

(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck drill pipe, Record the reason for postponing the test in the driller's report and conduct the required BOP test on the first trip out of the hole.

(d) BOP control station or pod that does not function properly, Suspend further drilling operations until that station or pod is operable.

(e) Want to drill with a tapered drill-string, Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller-size drill string.

(f) Install casing rams in a BOP stack, Test the ram bonnets before running casing.

(g) Want to use an annular BOP with a rated working pressure less than the anticipated surface pressure, Demonstrate that your well control procedures or the anticipated well conditions will not place demands above its rated working pressure and obtain approval from the District Manager.

(h) Use a subsea BOP system in an ice-scour area, Install the BOP stack in a glory hole. The glory hole must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.

(i) You activate blind-shear rams or casing shear rams during a well control situation, in which pipe or casing is sheared, Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled.

Drilling Fluid Requirements

§ 250.455   What are the general requirements for a drilling fluid program?

You must design and implement your drilling fluid program to prevent the loss of well control. This program must address drilling fluid safe practices, testing and monitoring equipment, drilling fluid quantities, and drilling fluid-handling areas.

§ 250.456   What 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;

(j) Before displacing kill-weight drilling fluid from the wellbore, you must obtain prior approval from the District Manager. To obtain approval, you must submit with your APD or APM your reasons for displacing the kill-weight drilling 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 that are in place for each flow path,

(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 fluids entering and leaving the wellbore; and

(k) In areas where permafrost and/or hydrate zones are present or may be present, you must control drilling fluid temperatures to drill safely through those zones.

§ 250.457   What equipment 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.

§ 250.458 What quantities of drilling fluids are required?

(a) You must use, maintain, and replenish quantities of drilling fluid and drilling fluid materials at the drill site as necessary to ensure well control. You must determine those quantities based on known or anticipated drilling conditions, rig storage capacity, weather conditions, and estimated time for delivery.

(b) You must record the daily inventories of drilling fluid and drilling fluid materials, including weight materials and additives in the drilling fluid report.

(c) If you do not have sufficient quantities of drilling fluid and drilling fluid material to maintain well control, you must suspend drilling operations.

§ 250.459 What are the safety requirements for drilling fluid-handling areas?

You must classify drilling fluid-handling areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities, 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.

Other Drilling Requirements

§ 250.460 What are the requirements for conducting a well test?

(a) If you intend to conduct a well test, you must include your projected plans for the test with your APD (form 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.

§ 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 directional well. You must conduct directional surveys on each directional well and digitally record the results. Surveys must give both inclination and azimuth at intervals not to exceed 500 feet during the normal course of drilling. Intervals during angle-changing portions of the hole may not exceed 100 feet.

(c) Measurement while drilling. You may use measurement-while-drilling technology if it meets the requirements of this section.

(d) Composite survey requirements. (1) Your composite directional survey must show the interval from the bottom of the conductor casing to total depth. In the absence of conductor casing, the survey must show the interval from the bottom of the drive or structural casing to total depth; and

(2) You must correct all surveys to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north after making the magnetic-to-true-north correction. Surveys must show the magnetic and grid corrections used and include a listing of the directionally computed inclinations and azimuths.

(e) If you drill within 500 feet of an adjacent lease, the Regional Supervisor may require you to furnish a copy of the well's directional survey to the affected leaseholder. This could occur when the adjoining leaseholder requests a copy of the survey for the protection of correlative rights.

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

You must conduct a weekly well-control drill with each drilling crew. Your drill must familiarize the crew with its roles and functions so that all crew members can perform their duties promptly and efficiently.

(a) Well-control drill plan. You must prepare a well control drill plan for each well. Your plan must outline the assignments for each crew member and establish times to complete each portion of the drill. You must post a copy of the well control drill plan on the rig floor or bulletin board.

(b) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to drilling operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping.

(c) Recordkeeping requirements. For each drill, you must record the following in the driller's report:

(1) The time to be ready to close the diverter or BOP system; and

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

(d) BSEE ordered drill. A BSEE authorized 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.

§ 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.

Applying for a Permit To Modify and Well Records

§ 250.465 When must I submit an Application for Permit to Modify (APM) or an End of Operations Report to 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 form BSEE–0124 with detailed information about the work to the District Manager, unless you have already provided sufficient information in a Well Activity Report, form BSEE–0133 (§250.468(b)).

§ 250.466 What records must I keep?

You must keep complete, legible, and accurate records for each well. You must keep drilling records onsite while drilling activities continue. After completion of drilling activities, you must keep all drilling and other well records for the time periods shown in §250.467. You may keep these records at a location of your choice. The records must contain complete information on all of the following:

(a) Well operations;

(b) Descriptions of formations penetrated;

(c) Content and character of oil, gas, water, and other mineral deposits in each formation;

(d) Kind, weight, size, grade, and setting depth of casing;

(e) All well logs and surveys run in the wellbore;

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager in the interests of resource evaluation, waste prevention, conservation of natural resources, and the protection of correlative rights, safety, and environment.

§ 250.467 How long must I keep records?

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

You must keep records relating to . . . Until . . .

(a) Drilling, Ninety days after you complete drilling operations.

(b) Casing and liner pressure tests, diverter tests, and BOP tests, Two years after the completion of drilling operations.

(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone, You permanently plug and abandon the well or until you forward the records with a lease assignment.

§ 250.468 What well records am I required to submit?

(a) You must submit copies of logs or charts of electrical, radioactive, sonic, and other well-logging operations; directional and vertical-well surveys; velocity profiles and surveys; and analysis of cores to BSEE. Each Region will provide specific instructions for submitting well logs and surveys.

(b) For drilling operations in the GOM OCS Region, you must submit form BSEE–0133, Well Activity Report, to the District Manager on a weekly basis.

(c) For drilling operations in the Pacific or Alaska OCS Regions, you must submit form BSEE–0133, Well Activity Report, to the District Manager on a daily basis.

§ 250.469 What other well records could I be required to submit?

The District Manager or Regional Supervisor may require you to submit copies of any or all of the following well records.

(a) Well records as specified in §250.466;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional

Supervisor may issue a Notice to Lessees that prescribes the manner, timeframe, and format for submitting this information;

(c) Service company reports on cementing, perforating, acidizing, testing, or other similar services; or

(d) Other reports and records of operations.

Hydrogen Sulfide

§ 250.490   Hydrogen sulfide.

(a) What precautions must I take when operating in an H 2 S area? You must:

(1) Take all necessary and feasible precautions and measures to protect personnel from the toxic effects of H2S and to mitigate damage to property and the environment caused by H2S. You must follow the requirements of this section when conducting drilling, well-completion/well-workover, and production operations in zones with H2S present and when conducting operations in zones where the presence of H2S is unknown. You do not need to follow these requirements when operating in zones where the absence of H2S 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 2 S absent means:

(1) Drilling, logging, coring, testing, or producing operations have confirmed the absence of H2S in concentrations that could potentially result in atmospheric concentrations of 20 ppm or more of H2S; or

(2) Drilling in the surrounding areas and correlation of geological and seismic data with equivalent stratigraphic units have confirmed an absence of H2S throughout the area to be drilled.

H 2 S present means that drilling, logging, coring, testing, or producing operations have confirmed the presence of H2S in concentrations and volumes that could potentially result in atmospheric concentrations of 20 ppm or more of H2S.

H 2 S unknown means the designation of a zone or geologic formation where neither the presence nor absence of H2S 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 2 S. You must:

(1) Request and obtain an approved classification for the area from the Regional Supervisor before you begin operations. Classifications are “H2S absent,” H2S present,” or “H2S 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 H2S that could potentially result in atmospheric concentrations of 20 ppm or more in areas not previously classified as having H2S present, you must immediately notify BSEE and begin to follow requirements for areas with H2S 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 2 S Contingency Plan. Before you begin operations, you must submit an H2S 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 H2S 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 H2S alert. You must have at least two briefing areas on each facility and use the briefing area that is upwind of the H2S 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 H2S alerts, describe the types of H2S 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_2concentration and exposure hazard when H_2S is burned;

(18) Increased monitoring and warning procedures you will take when the SO_2concentration in the atmosphere reaches 2 ppm;

(19) Personnel protection measures or evacuation procedures you will initiate when the SO_2concentration 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 H2S 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 H2S and SO2; and

(B) Instructions on their responsibilities in the event of an H2S release.

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

(i) Hazards of H2S and of SO2and the provisions for personnel safety contained in the H2S Contingency Plan;

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

(iii) Location of protective breathing equipment, H2S 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 H2S exposure. During all drills and training sessions, you must address procedures for rescue and first aid for H2S 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 2 S 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 H2S considerations at the facility, and other updated H2S 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 H2S and on facilities that process gas containing H2S 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 H2S 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-H2S,” 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 H2S.

(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 2 S-detection and H 2 S monitoring equipment: (1) What are the requirements for an H 2 S detection system? An H2S detection system must:

(i) Be capable of sensing a minimum of 10 ppm of H2S in the atmosphere; and

(ii) Activate audible and visual alarms when the concentration of H2S 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 H2S 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 H2S.

(4) How often must I observe the sensors? During drilling, well-completion and well-workover operations, you must continuously observe the H2S 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 H2S 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 H2S 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 H2S 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 H2S 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 2 S Detectors? (i) Personnel trained to calibrate the particular H2S detector equipment being used must test detectors by exposing them to a known concentration in the range of 10 to 30 ppm of H2S.

(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 H2S present or H2S 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 H2S 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 H2S-detection and H2S-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 H2S present or H2S unknown, you must equip vessels with an H2S-detection system that activates audible and visual alarms when the concentration of H2S 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 H2S Contingency Plan.

(10) What are the requirements for nearby facilities? The District Manager may require you to equip nearby facilities with portable or fixed H2S 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 H2S concentration levels could be exceeded at nearby facilities.

(11) What must I do to protect against SO 2 if I burn gas containing H 2 S? You must:

(i) Monitor the SO2concentration in the air with portable or strategically placed fixed devices capable of detecting a minimum of 2 ppm of SO2;

(ii) Take readings at least hourly and at any time personnel detect SO2odor or nasal irritation;

(iii) Implement the personnel protective measures specified in the H2S Contingency Plan if the SO2concentration 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 SO2.

(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 H2S present or H2S 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 H2S alerts, limit helicopter flights to and from facilities to the conditions specified in the H2S 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 H2S detectors capable of detecting a 10 ppm concentration of H2S 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 H2S or SO2may accumulate; and

(iii) Provide movable ventilation devices in work areas. The movable ventilation devices must be multidirectional and capable of dispersing H2S or SO2vapors 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 2 S 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 H2S 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 H2S present or H2S 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 H2S, you must immediately conduct either the Garrett-Gas-Train test or a comparable test for soluble sulfides to confirm the presence of H2S.

(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 H2S, well-control fluid pH, and corrosion equipment.

(i) Scavengers. You must have scavengers for control of H2S available on the facility. When H2S 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 H2S 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 H2S and other gases must be through pressurized or atmospheric mud-separator equipment depending on volume, pressure and concentration of H2S. 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 H2S and restore and maintain the proper quality.

(o) Well testing in a zone known to contain H 2 S. When testing a well in a zone with H2S 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 H2S 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 H2S 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 H2S, you must activate SO2monitoring equipment in accordance with paragraph (j)(11) of this section. If you detect SO2in excess of 2 ppm, you must implement the personnel protective measures in your H2S 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 H2S service.

(5) Use tubulars suitable for H2S 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 H2S 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 H2S service.

(p) Metallurgical properties of equipment. When operating in a zone with H2S 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 H2S 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 H2S service.

(2) Use BOP system components, wellhead, pressure-control equipment, and related equipment exposed to H2S-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 H2S service.

(4) When producing in zones bearing H2S, 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 2 S zone: (1) Coring operations. When you conduct coring operations in H2S-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 H2S.

(2) Logging operations. You must treat and condition well-control fluid in use for logging operations to minimize the effects of H2S 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 H2S reaches 20 ppm or if the well is under pressure.

(4) Gas-cut well-control fluid or well kick from H 2 S-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 H2S 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 (H2S and CO2) 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 H2S exists.

(8) Wireline lubricators. Lubricators which may be exposed to fluids containing H2S must be of H2S-resistant materials.

(9) Fuel and/or instrument gas. You must not use gas containing H2S for instrument gas. You must not use gas containing H2S 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 H2S-bearing fluids must be constructed of H2S-corrosion resistant materials or coated so as to resist H2S corrosion.

(11) Elastomer seals. You must use H2S-resistant materials for all seals which may be exposed to fluids containing H2S.

(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 H2S 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 H2S. The District Manager may require the submittal of an updated analysis if the water disposal rate or the potential H2S content increases.

(13) Deck drains. You must equip open deck drains with traps or similar devices to prevent the escape of H2S 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 H2S is present.