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Title 30: Mineral Resources

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

Subpart H—Oil and Gas Production Safety Systems

Contents

§250.800 General requirements.

(a) Production safety equipment shall be designed, installed, used, maintained, and tested in a manner to assure the safety and protection of the human, marine, and coastal environments. Production safety systems operated in subfreezing climates shall utilize equipment and procedures selected with consideration of floating ice, icing, and other extreme environmental conditions that may occur in the area. Production shall not commence until the production safety system has been approved and a preproduction inspection has been requested by the lessee.

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

(1) Comply with API RP 14J (as incorporated by reference in 30 CFR 250.198);

(2) Meet the drilling and production riser standards of API RP 2RD (as incorporated by reference in 30 CFR 250.198);

(3) Design all stationkeeping systems for floating facilities to meet the standards of API RP 2SK (as incorporated by reference in 30 CFR 250.198), as well as relevant U.S. Coast Guard regulations; and

(4) Design stationkeeping systems for floating facilities to meet structural requirements in subpart I, §§250.900 through 250.921 of this part.

§250.801 Subsurface safety devices.

(a) General. All tubing installations open to hydrocarbon-bearing zones shall be equipped with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after application and justification, the well is determined by the District Manager to be incapable of natural flowing. These devices may consist of a surface-controlled subsurface safety valve (SSSV), a subsurface-controlled SSSV, an injection valve, a tubing plug, or a tubing/annular subsurface safety device, and any associated safety valve lock or landing nipple.

(b) Specifications for SSSVs. Surface-controlled and subsurface-controlled SSSVs and safety valve locks and landing nipples installed in the OCS shall conform to the requirements in §250.806 of this part.

(c) Surface-controlled SSSVs. All tubing installations open to a hydrocarbon-bearing zone which is capable of natural flow shall be equipped with a surface-controlled SSSV, except as specified in paragraphs (d), (f), and (g) of this section. The surface controls may be located on the site or a remote location. Wells not previously equipped with a surface-controlled SSSV and wells in which a surface-controlled SSSV has been replaced with a subsurface-controlled SSSV in accordance with paragraph (d)(2) of this section shall be equipped with a surface-controlled SSSV when the tubing is first removed and reinstalled.

(d) Subsurface-controlled SSSVs. Wells may be equipped with subsurface-controlled SSSVs in lieu of a surface-controlled SSSV provided the lessee demonstrates to the District Manager's satisfaction that one of the following criteria are met:

(1) Wells not previously equipped with surface-controlled SSSVs shall be so equipped when the tubing is first removed and reinstalled,

(2) The subsurface-controlled SSSV is installed in wells completed from a single-well or multiwell satellite caisson or seafloor completions, or

(3) The subsurface-controlled SSSV is installed in wells with a surface-controlled SSSV that has become inoperable and cannot be repaired without removal and reinstallation of the tubing.

(e) Design, installation, and operation of SSSVs. The SSSVs shall be designed, installed, operated, and maintained to ensure reliable operation.

(1) The device shall be installed at a depth of 100 feet or more below the seafloor within 2 days after production is established. When warranted by conditions such as permafrost, unstable bottom conditions, hydrate formation, or paraffins, an alternate setting depth of the subsurface safety device may be approved by the District Manager.

(2) Until a subsurface safety device is installed, the well shall be attended in the immediate vicinity so that emergency actions may be taken while the well is open to flow. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

(3) The well shall not be open to flow while the subsurface safety device is removed, except when flowing of the well is necessary for a particular operation such as cutting paraffin, bailing sand, or similar operations.

(4) All SSSVs must be inspected, installed, maintained, and tested in accordance with American Petroleum Institute Recommended Practice 14B, Recommended Practice for Design, Installation, Repair, and Operation of Subsurface Safety Valve Systems (as specified in §250.198).

(f) Subsurface safety devices in shut-in wells. (1) New completions (perforated but not placed on production) and completions shut in for a period of 6 months shall be equipped with either—

(i) A pump-through-type tubing plug;

(ii) A surface-controlled SSSV, provided the surface control has been rendered inoperative; or

(iii) An injection valve capable of preventing backflow.

(2) The setting depth of the subsurface safety device shall be approved by the District Manager on a case-by-case basis, when warranted by conditions such as permafrost, unstable bottom conditions, hydrate formations, and paraffins.

(g) Subsurface safety devices in injection wells. A surface-controlled SSSV or an injection valve capable of preventing backflow shall be installed in all injection wells. This requirement is not applicable if the District Manager concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually.

(h) Temporary removal for routine operations. (1) Each wireline- or pumpdown-retrievable subsurface safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Form BSEE-0124, Application for Permit to Modify, in §250.601 of this part for a period not to exceed 15 days.

(2) The well shall be identified by a sign on the wellhead stating that the subsurface safety device has been removed. The removal of the subsurface safety device shall be noted in the records as required in §250.804(b) of this part. If the master valve is open, a trained person shall be in the immediate vicinity of the well to attend the well so that emergency actions may be taken, if necessary.

(3) A platform well shall be monitored, but a person need not remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mud line and the master valve closed, unless otherwise approved by the District Manager.

(4) The well shall not be allowed to flow while the subsurface safety device is removed, except when flowing the well is necessary for that particular operation. The provisions of this paragraph are not applicable to the testing and inspection procedures in §250.804 of this part.

(i) Additional safety equipment. All tubing installations in which a wireline- or pumpdown-retrievable subsurface safety device is installed after the effective date of this subpart shall be equipped with a landing nipple with flow couplings or other protective equipment above and below to provide for the setting of the SSSV. The control system for all surface-controlled SSSVs shall be an integral part of the platform Emergency Shutdown System (ESD). In addition to the activation of the ESD by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled

SSSVs shall close in response to shut-in signals from the ESD and in response to the fire loop or other fire detection devices.

(j) Emergency action. In the event of an emergency, such as an impending storm, any well not equipped with a subsurface safety device and which is capable of natural flow shall have the device properly installed as soon as possible with due consideration being given to personnel safety.

§250.802   Design, installation, and operation of surface production-safety systems.

(a) General. All production facilities, including separators, treaters, compressors, headers, and flowlines shall be designed, installed, and maintained in a manner which provides for efficiency, safety of operation, and protection of the environment.

(b) Platforms. You must protect all platform production facilities with a basic and ancillary surface safety system designed, analyzed, installed, tested, and maintained in operating condition in accordance with API RP 14C (as incorporated by reference in §250.198). If you use processing components other than those for which Safety Analysis Checklists are included in API RP 14C you must utilize the analysis technique and documentation specified therein to determine the effects and requirements of these components on the safety system. Safety device requirements for pipelines are under §250.1004.

(c) Specification for surface safety valves (SSV) and underwater safety valves (USV). All wellhead SSVs, USVs, and their actuators which are installed in the OCS shall conform to the requirements in §250.806 of this part.

(d) Use of SSVs and USV's. All SSVs and USVs must be inspected, installed, maintained, and tested in accordance with API RP 14H, Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (as incorporated by reference in §250.198). If any SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(e) Approval of safety-systems design and installation features. Prior to installation, the lessee shall submit, in duplicate for approval to the District Manager a production safety system application containing information relative to design and installation features. Information concerning approved design and installation features shall be maintained by the lessee at the lessee's offshore field office nearest the OCS facility or other location conveniently available to the District Manager. All approvals are subject to field verifications. The application shall include the following:

(1) A schematic flow diagram showing tubing pressure, size, capacity, design working pressure of separators, flare scrubbers, treaters, storage tanks, compressors, pipeline pumps, metering devices, and other hydrocarbon-handling vessels.

(2) A schematic piping flow diagram (API RP 14C, Figure E, as incorporated by reference in §250.198) and the related Safety analysis Function Evaluation chart (API RP 14C, subsection 4.3c, as incorporated by reference in §250.198).

(3) A schematic piping diagram showing the size and maximum allowable working pressures as determined in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems (as incorporated by reference in §250.198).

(4) Electrical system information including the following:

(i) A plan for each platform deck outlining all hazardous areas classified according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (as incorporated by reference in §250.198), and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outlined will include the following information:

(A) All major production equipment, wells, and other significant hydrocarbon sources and a description of the type of decking, ceiling, walls (e.g., grating or solid) and firewalls; and

(B) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (e.g., type cable, conduit, or wire).

(ii) Elementary electrical schematic of any platform safety shut-down system with a functional legend.

(5) Certification that the design for the mechanical and electrical systems to be installed were approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Manager certifying that new installations conform to the approved designs of this subpart.

(6) The design and schematics of the installation and maintenance of all fire- and gas-detection systems shall include the following:

(i) Type, location, and number of detection sensors;

(ii) Type and kind of alarms, including emergency equipment to be activated;

(iii) Method used for detection;

(iv) Method and frequency of calibration; and

(v) A functional block diagram of the detection system, including the electric power supply.

(7) The service fee listed in §250.125. The fee you must pay will be determined by the number of components involved in the review and approval process.

§250.803 Additional production system requirements.

(a) For all production platforms, you must comply with the following production safety system requirements, in addition to the requirements of §250.802 of this subpart and the requirements of API RP 14C (as incorporated by reference in §250.198).

(b) Design, installation, and operation of additional production systems—(1) Pressure and fired vessels. Pressure and fired vessels must be designed, fabricated, and code stamped in accordance with the applicable provisions of Sections I, IV, and VIII of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Pressure and fired vessels must have maintenance inspection, rating, repair, and alteration performed in accordance with the applicable provisions of API Pressure Vessel Inspections Code: In-Service Inspection, Rating, Repair, and Alteration, API 510 (except Sections 5.8 and 9.5) (as incorporated by reference in §250.198).

(i) Pressure relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII of the ASME Boiler and Pressure Vessel Code. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves, except completely redundant relief valves, shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

(ii) Steam generators operating at less than 15 pounds per square inch gauge (psig) shall be equipped with a level safety low (LSL) sensor which will shut off the fuel supply when the water level drops below the minimum safe level. Steam generators operating at greater than 15 psig require, in addition to an LSL, a water-feeding device which will automatically control the water level.

(iii) The lessee shall use pressure recorders to establish the new operating pressure ranges of pressure vessels at any time when there is a change in operating pressures that requires new settings for the high-pressure shut-in sensor and/or the low-pressure shut-in sensor as provided herein. The pressure-recorder charts used to determine current operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Manager. The high-pressure shut-in sensor shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the vessel. This setting shall also be set sufficiently below (5 percent or 5 psi, whichever is greater) the relief valve's set pressure to assure that the pressure source is shut in before the relief valve activates. The low-pressure shut-in sensor shall activate no lower than 15 percent or 5 psi, whichever is greater, below the lowest pressure in the operating range. The activation of low-pressure sensors on pressure vessels which operate at less than 5 psi shall be approved by the District Manager on a case-by-case basis.

(2) Flowlines. (i) You must equip flowlines from wells with high- and low-pressure shut-in sensors located in accordance with section A.1 and Figure A1 of API RP 14C (as incorporated by reference in §250.198). The lessee shall use pressure recorders to establish the new operating pressure ranges of flowlines at any time when there is a significant change in operating pressures. The most recent pressure-recorder charts used to determine operating pressure ranges shall be maintained at the lessee's field office nearest the OCS facility or at other locations conveniently available to the District Manager. The high-pressure shut-in sensor(s) shall be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the line. But in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the SSV. The low-pressure shut-in sensor(s) shall be set no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the line in which it is installed.

(ii) If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of and including the header inlet valve(s) shall have a working pressure equal to or greater than the maximum shut-in pressure of the well unless the flowline is protected by one of the following:

(A) A relief valve which vents into the platform flare scrubber or some other location approved by the District Manager. The platform flare scrubber shall be designed to handle, without liquid-hydrocarbon carryover to the flare, the maximum-anticipated flow of liquid hydrocarbons which may be relieved to the vessel.

(B) Two SSV's with independent high-pressure sensors installed with adequate volume upstream of any block valve to allow sufficient time for the valve(s) to close before exceeding the maximum allowable working pressure.

(iii) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(A) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec 17J (as incorporated by reference in §250.198);

(B) Determine that the unbonded flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way;

(C) Submit to the BSEE District Manager the manufacturer's design specifications for the unbonded flexible pipe; and

(D) Submit to the BSEE District Manager a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of API Spec 17J (as incorporated by reference in §250.198).

(3) Safety sensors. All shutdown devices, valves, and pressure sensors shall function in a manual reset mode. Sensors with integral automatic reset shall be equipped with an appropriate device to override the automatic reset mode. All pressure sensors shall be equipped to permit testing with an external pressure source.

(4) ESD. The ESD must conform to the requirements of Appendix C, section C1, of API RP 14C (as incorporated by reference in §250.198), and the following:

(i) The manually operated ESD valve(s) shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. Only ESD stations at the boat landing may utilize a loop of breakable synthetic tubing in lieu of a valve.

(ii) Closure of the SSV shall not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV shall close in not more than 2 minutes after the shut-in signal has closed the SSV. Design-delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and be approved by the District Manager.

(iii) A schematic of the ESD which indicates the control functions of all safety devices for the platforms shall be maintained by the lessee on the platform or at the lessee's field office nearest the OCS facility or other location conveniently available to the District Manager.

(5) Engines: (i) Engine exhaust. You must equip engine exhausts to comply with the insulation and personnel protection requirements of API RP 14C, section 4.2c(4) (as incorporated by reference in §250.198). Exhaust piping from diesel engines must be equipped with spark arresters.

(ii) Diesel engine air intake. All diesel engine air intakes must be equipped with a device to shutdown the diesel engine in the event of runaway. Diesel engines that are continuously attended must be equipped with either remote operated manual or automatic shutdown devices. Diesel engines that are not continuously attended must be equipped with automatic shutdown devices.

(6) Glycol dehydration units. A pressure relief system or an adequate vent shall be installed on the glycol regenerator (reboiler) which will prevent overpressurization. The discharge of the relief valve shall be vented in a nonhazardous manner.

(7) Gas compressors. You must equip compressor installations with the following protective equipment as required in API RP 14C, Sections A4 and A8 (as incorporated by reference in §250.198).

(i) A Pressure Safety High (PSH), a Pressure Safety Low (PSL), a Pressure Safety Valve (PSV), and a Level Safety High (LSH), and an LSL to protect each interstage and suction scrubber.

(ii) A Temperature Safety High (TSH) on each compressor discharge cylinder.

(iii) The PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designated to actuate automatic shutdown valves (SDV) located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources. All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover. Unless otherwise approved by the District Manager, gas—well gas affected by the closure of the automatic SDV on a compressor suction shall be diverted to the pipeline or shut in at the wellhead.

(iv) A blowdown valve is required on the discharge line of all compressor installations of 1,000 horsepower (746 kilowatts) or greater.

(8) Firefighting systems. Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons shall conform to subsection 5.2, Firewater systems, of API RP 14G (as incorporated by reference in §250.198), Fire Prevention and Control Open Type Offshore Production Platforms, and shall require approval of the District Manager. The following additional requirements shall apply for both open- and closed-production platforms:

(i) A firewater system consisting of rigid pipe with firehose stations or fixed firewater monitors shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed waterspray system shall be installed in enclosed well-bay areas where hydrocarbon vapors may accumulate.

(ii) Fuel or power for firewater pump drivers shall be available for at least 30 minutes of run time during a platform shut-in. If necessary, an alternate fuel or power supply shall be installed to provide for this pump-operating time unless an alternate firefighting system has been approved by the District Manager.

(iii) A firefighting system using chemicals may be used in lieu of a water system if the District Manager determines that the use of a chemical system provides equivalent fire-protection control.

(iv) A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the facility or structure.

(v) For operations in subfreezing climates, the lessee shall furnish evidence to the District Manager that the firefighting system is suitable for the conditions.

(9) Fire- and gas-detection system. (i) Fire (flame, heat, or smoke) sensors shall be installed in all enclosed classified areas. Gas sensors shall be installed in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation which is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit (LEL). One approved method of providing adequate ventilation is a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater. Enclosed areas (e.g., buildings, living quarters, or doghouses) are defined as those areas confined on more than four of their six possible sides by walls, floors, or ceilings more restrictive to air flow than

grating or fixed open louvers and of sufficient size to all entry of personnel. A classified area is any area classified Class I, Group D, Division 1 or 2, following the guidelines of API RP 500 (as incorporated by reference in §250.198), or any area classified Class I, Zone 0, Zone 1, or Zone 2, following the guidelines of API RP 505 (as incorporated by reference in §250.198).

(ii) All detection systems shall be capable of continuous monitoring. Fire-detection systems and portions of combustible gas-detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas-detection systems related to the lower gas-concentration level may be of the automatic-reset type.

(iii) A fuel-gas odorant or an automatic gas-detection and alarm system is required in enclosed, continuously manned areas of the facility which are provided with fuel gas. Living quarters and doghouses not containing a gas source and not located in a classified area do not require a gas detection system.

(iv) The District Manager may require the installation and maintenance of a gas detector or alarm in any potentially hazardous area.

(v) Fire- and gas-detection systems must be an approved type, designed and installed according to API RP 14C, API RP 14G, and either API RP 14F or API RP 14FZ (the preceding four documents as incorporated by reference in §250.198).

(10) Electrical equipment. Electrical equipment and systems shall be designed, installed, and maintained in accordance with the requirements in §250.114 of this part.

(11) Erosion. A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. Records by lease, indicating the wells which have erosion-control programs in effect and the results of the programs, shall be maintained by the lessee for a period of 2 years and shall be made available to BSEE upon request.

(c) General platform operations. (1) Surface or subsurface safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions until the safety devices are placed back in service. Any surface or subsurface safety device which is temporarily out of service shall be flagged.

(2) When wells are disconnected from producing facilities and blind flanged, equipped with a tubing plug, or the master valves have been locked closed, you are not required to comply with the provisions of API RP 14C (as incorporated by reference in §250.198) or this regulation concerning the following:

(i) Automatic fail-close SSV's on wellhead assemblies, and

(ii) The PSH and PSL shut-in sensors in flowlines from wells.

(3) When pressure or atmospheric vessels are isolated from production facilities (e.g., inlet valve locked closed or inlet blind-flanged) and are to remain isolated for an extended period of time, safety device compliance with API RP 14C or this subpart is not required.

(4) All open-ended lines connected to producing facilities and wells shall be plugged or blind-flanged, except those lines designed to be open-ended such as flare or vent lines.

(d) Welding and burning practices and procedures. All welding, burning, and hot-tapping activities shall be conducted according to the specific requirements in §§250.109 through 250.113 of this part.

§250.804 Production safety-system testing and records.

(a) Inspection and testing. The safety-system devices shall be successfully inspected and tested by the lessee at the interval specified below or more frequently if operating conditions warrant. Testing must be in accordance with API RP 14C, Appendix D (as incorporated by reference in §250.198), and the following:

(1) Testing requirements for subsurface safety devices are as follows:

(i) Each surface-controlled subsurface safety device installed in a well, including such devices in shut-in and injection wells, shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, or if a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. Testing shall be in accordance with API RP 14B (as incorporated by reference in §250.198) to ensure proper operation.

(ii) Each subsurface-controlled SSSV installed in a well shall be removed, inspected, and repaired or adjusted, as necessary, and reinstalled or replaced at intervals not exceeding 6 months for those valves not installed in a landing nipple and 12 months for those valves installed in a landing nipple.

(iii) Each tubing plug installed in a well shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 200 cubic centimeters per minute or a gas leakage rate in excess of 5 cubic feet per minute is observed, the device shall be removed, repaired and reinstalled, or replaced. An additional tubing plug may be installed in lieu of removal.

(iv) Injection valves shall be tested in the manner as outlined for testing tubing plugs in paragraph (a)(1)(iii) of this section. Leakage rates outlined in paragraph (a)(1)(iii) of this section shall apply.

(2) All PSV's shall be tested for operation at least once every 12 months. These valves shall be either bench-tested or equipped to permit testing with an external pressure source. Weighted disk vent valves used as PSV's on atmospheric tanks may be disassembled and inspected in lieu of function testing.

(3) The following safety devices (excluding electronic pressure transmitters and level sensors) must be tested at least once each calendar month, but at no time will more than 6 weeks elapse between tests:

(i) All PSH and PSL,

(ii) All LSH and LSL controls,

(iii) All automatic inlet SDV's which are actuated by a sensor on a vessel or compressor, and

(iv) All SDV's in liquid discharge lines and actuated by vessel low-level sensors.

(4) The following electronic pressure transmitters and level sensors must be tested at least once every 3 months, but at no time may more than 120 days elapse between tests:

(i) All PSH and PSL, and

(ii) All LSH and LSL controls.

(5) All SSV's and USV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The SSV's and USV's must be tested in accordance with the test procedures specified in API RP 14H (as incorporated by reference in §250.198). If the SSV or USV does not operate properly or if any fluid flow is observed during the leakage test, the valve shall be repaired or replaced.

(6) All flowline Flow Safety Valves (FSV) shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's must be tested for leakage in accordance with the test procedures specified in API RP 14C, Appendix D, section D4, table D2, subsection D (as incorporated by reference in §250.198). If the leakage measured exceeds a liquid flow of 200 cubic centimeters per minute or a gas flow of 5 cubic feet per minute, the FSV's shall be repaired or replaced.

(7) The TSH shutdown controls installed on compressor installations which can be nondestructively tested shall be tested every 6 months and repaired or replaced as necessary.

(8) All pumps for firewater systems shall be inspected and operated weekly.

(9) All fire- (flame, heat, or smoke) detection systems shall be tested for operation and recalibrated every 3 months provided that testing can be performed in a nondestructive manner. Open flame or devices operating at temperatures which could ignite a methane-air mixture shall not be used. All combustible gas-detection systems shall be calibrated every 3 months.

(10) All TSH devices shall be tested at least once every 12 months, excluding those addressed in paragraph (a)(7) of this section and those which would be destroyed by testing. Burner safety low and flow safety low devices shall also be tested at least once every 12 months.

(11) The ESD shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The test shall be conducted by alternating ESD stations monthly to close at least one wellhead SSV and verify a surface-controlled SSSV closure for that well as indicated by control circuitry actuation.

(12) Prior to the commencement of production, the lessee shall notify the District Manager when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Manager upon commencement of production in order that a complete inspection may be conducted.

(b) Records. The lessee shall maintain records for a period of 2 years for each subsurface and surface safety device installed. These records shall be maintained by the lessee at the lessee's field office nearest the OCS facility or other locations conveniently available to the District Manager. These records shall be available for review by a representative of BSEE. The records shall show the present status and history of each device, including dates and details of installation, removal, inspection, testing, repairing, adjustments, and reinstallation.

§250.805 Safety device training.

Personnel installing, inspecting, testing, and maintaining these safety devices and personnel operating the production platforms shall be qualified in accordance with 30 CFR 250, subpart O.

§250.806 Safety and pollution prevention equipment quality assurance requirements.

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

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

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

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

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

(i) ANSI/ASME SPPE-1-1994 and SPPE-1d-1996 Addenda, Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations (as incorporated by reference in §250.198); and

(ii) API Spec Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry (as incorporated by reference in §250.198).

(3) All SSV's and USV's must meet the technical specifications of API Spec 6A and 6AV1. All SSSVs must meet the technical specifications of API Specification 14A (as incorporated by reference in §250.198). However, SSSVs and related equipment planned to be used in high pressure high temperature environments must meet the additional requirements set forth in §250.807.

(4) For information on all standards mentioned in this section, see §250.198.

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

(2) On or after April 1, 1998:

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

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

(c) Recognizing other quality assurance programs. The BSEE will consider recognizing other quality assurance programs covering the manufacture of SPPE. If you want BSEE to evaluate other quality assurance programs, submit relevant information about the program and reasons for recognition by BSEE to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; MS-4020; 381 Elden Street, Herndon, Virginia 20170-4817.

§250.807 Additional requirements for subsurface safety valves and related equipment installed in high pressure high temperature (HPHT) environments.

(a) If you plan to install SSSVs and related equipment in an HPHT environment, you must submit detailed information with your Application for Permit to Drill (APD), Application for Permit to Modify (APM), or

Deepwater Operations Plan (DWOP) that demonstrates the SSSVs and related equipment are capable of performing in the applicable HPHT environment. Your detailed information must include the following:

(1) A discussion of the SSSVs' and related equipment's design verification analysis;

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

(3) An explanation of why the analysis, process, and procedures ensure that the SSSVs and related equipment are fit-for-service in the applicable HPHT environment.

(b) For this section, HPHT environment means when one or more of the following well conditions exist:

(1) The completion of the well requires completion equipment or well control equipment assigned a pressure rating greater than 15,000 psig or a temperature rating greater than 350 degrees Fahrenheit;

(2) The maximum anticipated surface pressure or shut-in tubing pressure is greater than 15,000 psig on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead; or

(3) The flowing temperature is equal to or greater than 350 degrees Fahrenheit on the seafloor for a well with a subsea wellhead or at the surface for a well with a surface wellhead.

(c) For this section, related equipment includes wellheads, tubing heads, tubulars, packers, threaded connections, seals, seal assemblies, production trees, chokes, well control equipment, and any other equipment that will be exposed to the HPHT environment.

§250.808   Hydrogen sulfide.

Production operations in zones known to contain hydrogen sulfide (H2S) or in zones where the presence of H2S is unknown, as defined in §250.490 of this part, shall be conducted in accordance with that section and other relevant requirements of subpart H, Production Safety Systems.