(n) Date of diagnostic test;

(o) Well schematic;

(p) Water depth;

(q) Volumes and types of fluid bled from each casing or riser evaluated;

(r) Type of diagnostic test performed:

(1) Bleed down/buildup test;

(2) Shut-in the well and monitor the pressure drop test;

(3) Constant production rate and decrease the annular pressure test;

(4) Constant production rate and increase the annular pressure test;

(5) Change the production rate and monitor the casing pressure test; and

(6) Casing pressure and tubing pressure history plot;

(s) The casing diagnostic test data for all casing exceeding 100 psig;

(t) Associated shoe strengths for casing shoes exposed to annular fluids;

(u) Concentration of any H_2S that may be present;

(v) Whether the structure on which the well is located is manned or unmanned;

(w) Additional comments; and

(x) Request date.

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

§ 250.529 What are the terms of my casing pressure request?

Casing pressure requests are approved by the Regional Supervisor, Field Operations, for a term to be determined by the Regional Supervisor on a case-by-case basis. The Regional Supervisor may impose additional restrictions or requirements to allow continued operation of the well.

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

§ 250.530 What if my casing pressure request is denied?

(a) If your casing pressure request is denied, then the operating company must submit plans for corrective action to the respective District Manager within 30 days of receiving the denial. The District Manager will establish a specific time period in which this corrective action will be taken. You must notify the respective District Manager within 30 days after completion of your corrected action.

(b) You must submit the casing diagnostic test data to the appropriate Regional Supervisor, Field Operations, within 14 days of completion of the diagnostic test required under § 250.522(e).

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

§ 250.531 When does my casing pressure request approval become invalid?

A casing pressure request becomes invalid when:

(a) The casing or riser pressure increases by 200 psig over the approved casing pressure request pressure;

(b) The approved term ends;

(c) The well is worked-over, side-tracked, redrilled, recompleted, or acid stimulated;

(d) A different casing or riser on the same well requires a casing pressure request; or

(e) A well has more than one casing operating under a casing pressure request and one of the casing pressure requests become invalid, then all casing pressure requests for that well become invalid.

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

Subpart F—Oil and Gas Well-Workover Operations

§ 250.600 General requirements.

Well-workover operations shall be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment.

§ 250.601 Definitions.

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

Expected surface pressure means the highest pressure predicted to be exerted upon the surface of a well. In calculating expected surface pressure, you must consider reservoir pressure as well as applied surface pressure.

Routine operations mean any of the following operations conducted on a well with the tree installed:

(a) Cutting paraffin;

(b) Removing and setting pump-through-type tubing plugs, gas-lift valves, and subsurface safety valves which can be removed by wireline operations;

(c) Bailing sand;

(d) Pressure surveys;

(e) Swabbing;

(f) Scale or corrosion treatment;

(g) Caliper and gauge surveys;

(h) Corrosion inhibitor treatment;

(i) Removing or replacing subsurface pumps;

(j) Through-tubing logging (diagnostics);

(k) Wireline fishing; and

(l) Setting and retrieving other subsurface flow-control devices.

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

§ 250.602 Equipment movement.

The movement of well-workover rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-workover rigs and related equipment unless otherwise approved by the District Manager. A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation. The well to which a well-workover rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the tree and installing and testing the blowout-preventer (BOP) system. The well from which a well-workover rig or related equipment is to be moved shall also be equipped with a back pressure valve prior to removing the BOP system and installing the tree. Coiled tubing units, snubbing units, or wireline units may be moved onto a platform without shutting in wells.

§ 250.603 Emergency shutdown system.

When well-workover operations are conducted on a well with the tree removed, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station, except when there is no other hydrocarbon-producing well or other hydrocarbon flow on the platform.

§ 250.604 Hydrogen sulfide.

When a well-workover operation is conducted in zones known to contain hydrogen sulfide (H_2S) or in zones where the presence of H_2S is unknown (as defined in § 250.490 of this part), the lessee shall take appropriate precautions to protect life and property on the platform or rig, including but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps and packers. The lessee shall comply with the requirements in § 250.490 of this part as well as the appropriate requirements of this subpart.

§ 250.605 Subsea workovers.

No subsea well-workover operation including routine operations shall be commenced until the lessee obtains written approval from the District Manager in accordance with § 250.613 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will maintain adequate control of the well and permit continued safe production operations.

§ 250.606 Crew instructions.

Prior to engaging in well-workover operations, crew members shall be instructed in the safety requirements of the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment. Date and time of safety meetings shall be recorded and available at the facility for review by a BSEE representative.

§§ 250.607–250.608 [Reserved]

§ 250.609 Well-workover structures on fixed platforms.

Derricks, masts, substructures, and related equipment shall be selected, designed, installed, used, and maintained so as to be adequate for the potential loads and conditions of loading that may be encountered during the operations proposed. Prior to moving a well-workover rig or well-servicing equipment onto a platform, the lessee shall determine the structural capability of the platform to safely support the equipment and proposed operations, taking into consideration the corrosion protection, age of the platform, and previous stresses to the platform.

§ 250.610 Diesel engine air intakes.

No later than May 31, 1989, diesel engine air intakes shall be equipped with a device to shut down the diesel engine in the event of runaway. Diesel engines which are continuously attended shall be equipped with either remote operated manual or automatic shutdown devices. Diesel engines which are not continuously attended shall be equipped with automatic shutdown devices.

§ 250.611 Traveling-block safety device.

After May 31, 1989, all units being used for well-workover operations which have both a traveling block and a crown block shall be equipped with a safety device which is designed to prevent the traveling block from striking the crown block. The device shall be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check shall be entered in the operations log.

§ 250.612 Field well-workover rules.

When geological and engineering information available in a field enables the District Manager to determine specific operating requirements, field well-workover rules may be established on the District Manager's initiative or in response to a request from a lessee. Such rules may modify the specific requirements of this subpart. After field well-workover rules have been established, well-workover operations in the field shall be conducted in accordance with such rules and other requirements of this subpart. Field well-workover rules may be amended or canceled for cause at any time upon the initiative of the District Manager or upon the request of a lessee.

§ 250.613 Approval and reporting for well-workover operations.

(a) No well-workover operation except routine ones, as defined in § 250.601 of this part, shall begin until the lessee receives written approval from the District Manager. Approval for these operations must be requested on Form BSEE–0124, Application for Permit to Modify.

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

(1) A brief description of the well-workover procedures to be followed, a statement of the expected surface pressure, and type and weight of workover fluids;

(2) When changes in existing subsurface equipment are proposed, a schematic drawing of the well showing the zone proposed for workover and the workover equipment to be used;

(3) All information required in § 250.615.

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

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

(c) The following additional information shall be submitted with Form BSEE–0124 if completing to a new zone is proposed:

(1) Reason for abandonment of present producing zone including supportive well test data, and

(2) A statement of anticipated or known pressure data for the new zone.

(d) Within 30 days after completing the well-workover operation, except routine operations, Form BSEE–0124, Application for Permit to Modify, shall be submitted to the District Manager, showing the work as performed. In the case of a well-workover operation resulting in the initial recompletion of a well into a new zone, a Form BSEE–

0125, End of Operations Report, shall be submitted to the District Manager and shall include a new schematic of the tubing subsurface equipment if any subsurface equipment has been changed.

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

§250.614 Well-control fluids, equipment, and operations.

The following requirements apply during all well-workover operations with the tree removed:

(a) Well-control fluids, equipment, and operations shall be designed, utilized, maintained, and/or tested as necessary to control the well in foreseeable conditions and circumstances, including subfreezing conditions. The well shall be continuously monitored during well-workover operations and shall not be left unattended at anytime unless the well is shut in and secured.

(b) When coming out of the hole with drill pipe or a workover string, the annulus shall be filled with well-control fluid before the change in such fluid level decreases the hydrostatic pressure 75 pounds per square inch (psi) or every five stands of drill pipe or workover string, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe or workover string and drill collars that may be pulled prior to filling the hole and the equivalent well-control fluid volume shall be calculated and posted near the operator's station. A mechanical, volumetric, or electronic device for measuring the amount of well-control fluid required to fill the hold shall be utilized.

(c) The following well-control-fluid equipment shall be installed, maintained, and utilized:

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

(2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and

(3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

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

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

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

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

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

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

§250.615 What BOP information must I submit?

For well-workover operations, your APM must include the following BOP descriptions:

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

(b) 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;

(c) 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 (including workstring and tubing) in the hole under maximum anticipated surface pressure. The documentation must include actual shearing and subsequent pressure integrity test results for the most rigid pipe to be used and calculations of shearing capacity of all pipe to be used in the well, including correction for under maximum anticipated surface pressure;

(d) 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

(e) The qualifications of the independent third-party referenced in paragraphs (c) and (d) of this section:

(1) The independent third-party in this section must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the verifications required under this part.

(2) You must:

(i) Include evidence that the registered professional engineer, or a technical classification society, or engineering firm you are using or its employees hold appropriate licenses to perform the verification in the appropriate jurisdiction, and evidence to demonstrate that the individual, society, or firm has the expertise and experience necessary to perform the required verifications.

(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 BSEE District Manager at least 72 hours in advance.

[77 FR 50895, Aug. 22, 2012]

§ 250.616 Blowout prevention equipment.

(a) The BOP system, system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form BSEE–0124, requesting approval of the well-workover operation, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

(b) The minimum BOP system for well-workover operations with the tree removed must meet the appropriate standards from the following table:

When . . .	The minimum BOP stack must include . . .
(1) The expected pressure is less than 5,000 psi,	Three BOPs consisting of an annular, one set of pipe rams, and one set of blind-shear rams.
(2) The expected pressure is 5,000 psi or greater or you use multiple tubing strings,	Four BOPs consisting of an annular, two sets of pipe rams, and one set of blind-shear rams.
(3) You handle multiple tubing strings simultaneously,	Four BOPs consisting of an annular, one set of pipe rams, one set of dual pipe rams, and one set of blind-shear rams.
(4) You use a tapered drill string,	At least one set of pipe rams that are capable of sealing around each size of drill string. If the expected pressure is greater than 5,000 psi, then you must have at least two sets of pipe rams that are capable of sealing around the larger size drill string. You may substitute one set of variable bore rams for two sets of pipe rams.
(5) You use a subsea BOP stack,	The requirements in § 250.442(a) of this part.

(c) The BOP systems for well-workover operations with the tree removed must be equipped with the following:

(1) A hydraulic-actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a charging system. Accumulator regulators supplied by rig air and without a secondary source of pneumatic supply, must be equipped with manual overrides, or alternately, other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) A secondary power source, independent from the primary power

source, with sufficient capacity to close all BOP system components and hold them closed;

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

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

(5) A choke line and a kill line each equipped with two full opening valves and a choke manifold. At least one of the valves on the choke-line shall be remotely controlled. At least one of the valves on the kill line shall be remotely controlled, except that a check valve on the kill line in lieu of the remotely controlled valve may be installed provided two readily accessible manual valves are in place and the check valve is placed between the manual valves and the pump. This equipment shall have a pressure rating at least equivalent to the ram preventers.

(d) The minimum BOP-system components for well-workover operations with the tree in place and performed through the wellhead inside of conventional tubing using small-diameter jointed pipe (usually ¾ inch to 1¼ inch) as a work string, *i.e.*, small-tubing operations, shall include the following:

(1) Two sets of pipe rams, and

(2) One set of blind rams.

(e) The subsea BOP system for well-workover operations must meet the requirements in § 250.442 of this part.

(f) For coiled tubing operations with the production tree in place, you must meet the following minimum requirements for the BOP system:

(1) BOP system components must be in the following order from the top down:

BOP system when expected surface pressures are less than or equal to 3,500 psi	BOP system when expected surface pressures are greater than 3,500 psi	BOP system for wells with returns taken through an outlet on the BOP stack
Stripper or annular-type well control component.	Stripper or annular-type well control component.	Stripper or annular-type well control component.
Hydraulically-operated blind rams	Hydraulically-operated blind rams	Hydraulically-operated blind rams
Hydraulically-operated shear rams	Hydraulically-operated shear rams	Hydraulically-operated shear rams.
Kill line inlet	Kill line inlet	Kill line inlet.
Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams	Hydraulically-operated two-way slip rams.
		Hydraulically-operated pipe rams.
Hydraulically-operated pipe rams	Hydraulically-operated pipe rams	A flow tee or cross.
	Hydraulically-operated blind-shear rams. These rams should be located as close to the tree as practical.	Hydraulically-operated pipe rams.
		Hydraulically-operated blind-shear rams on wells with surface pressures > 3,500 psi. As an option, the pipe rams can be placed below the blind-shear rams. The blind-shear rams should be located as close to the tree as practical.

(2) You may use a set of hydraulically-operated combination rams for the blind rams and shear rams.

(3) You may use a set of hydraulically-operated combination rams for the hydraulic two-way slip rams and the hydraulically-operated pipe rams.

(4) You must attach a dual check valve assembly to the coiled tubing connector at the downhole end of the coiled tubing string for all coiled tubing well-workover operations. If you plan to conduct operations without downhole check valves, you must describe alternate procedures and equipment in Form BSEE–0124, Application for Permit to Modify and have it approved by the District Manager.

(5) You must have a kill line and a separate choke line. You must equip each line with two full-opening valves and at least one of the valves must be remotely controlled. You may use a manual valve instead of the remotely controlled valve on the kill line if you install a check valve between the two full-opening manual valves and the pump or manifold. The valves must have a working pressure rating equal to or greater than the working pressure rating of the connection to which they are attached, and you must install them between the well control

stack and the choke or kill line. For operations with expected surface pressures greater than 3,500 psi, the kill line must be connected to a pump or manifold. You must not use the kill line inlet on the BOP stack for taking fluid returns from the wellbore.

(6) You must have a hydraulic-actuating system that provides sufficient accumulator capacity to close-open-close each component in the BOP stack. This cycle must be completed with at least 200 psi above the pre-charge pressure, without assistance from a charging system.

(7) All connections used in the surface BOP system from the tree to the uppermost required ram must be flanged, including the connections between the well control stack and the first full-opening valve on the choke line and the kill line.

(g) The minimum BOP-system components for well-workover operations with the tree in place and performed by moving tubing or drill pipe in or out of a well under pressure utilizing equipment specifically designed for that purpose, *i.e.*, snubbing operations, shall include the following:

(1) One set of pipe rams hydraulically operated, and

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

(h) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-workover operations when the tree is removed or during well-workover operations with the tree installed and using small tubing as the work string. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string. The full-opening safety valve is not required for coiled tubing or snubbing operations.

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

§ 250.617 Blowout preventer system testing, records, and drills.

(a) *BOP pressure tests.* When you pressure test the BOP system you must conduct a low-pressure test and a high-pressure test for each component. You must conduct the low-pressure test before the high-pressure test. For purposes of this section, BOP system components include ram-type BOP's, related control equipment, choke and kill lines, and valves, manifolds, strippers, and safety valves. Surface BOP systems must be pressure tested with water.

(1) *Low pressure tests.* All BOP system components must be successfully tested to a low pressure between 200 and 300 psi. Any initial pressure equal to or greater than 300 psi must be bled back to a pressure between 200 and 300 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero before starting the test.

(2) *High pressure tests.* All BOP system components must be successfully tested to the rated working pressure of the BOP equipment, or as otherwise approved by the District Manager. The annular-type BOP must be successfully tested at 70 percent of its rated working pressure or as otherwise approved by the District Manager.

(3) *Other testing requirements.* Variable bore pipe rams must be pressure tested against the largest and smallest sizes of tubulars in use (jointed pipe, seamless pipe) in the well.

(b) Times. The BOP systems shall be tested at the following times:

(1) When installed;

(2) At least every 7 days, alternating between control stations and at staggered intervals to allow each crew to operate the equipment. If either control system is not functional, further operations shall be suspended until the nonfunctional, system is operable. The test every 7 days is not required for blind or blind-shear rams. The blind or blind-shear rams shall be tested at least once every 30 days during operation. A longer period between blowout preventer tests is allowed when there is a stuck pipe or pressure-control operation and remedial efforts are being performed. The tests shall be conducted as soon as possible and before normal operations resume. The reason for postponing testing shall be entered into the operations log.

(3) Following repairs that require disconnecting a pressure seal in the assembly, the affected seal will be pressure tested.

(c) *Drills.* All personnel engaged in well-workover operations shall participate in a weekly BOP drill to familiarize crew members with appropriate safety measures.

(d) *Stump tests.* You may conduct a stump test for the BOP system on location. A plan describing the stump test procedures must be included in your Form BSEE–0124, Application for Permit to Modify, and must be approved by the District Manager.

(e) *Coiled tubing tests.* You must test the coiled tubing connector to a low pressure of 200 to 300 psi, followed by a high pressure test to the rated working pressure of the connector or the expected surface pressure, whichever is less. You must successfully pressure test the dual check valves to the rated working pressure of the connector, the rated working pressure of the dual check valve, expected surface pressure, or the collapse pressure of the coiled tubing, whichever is less.

(f) *Recordings.* You must record test pressures during BOP and coiled tubing tests on a pressure chart, or with a digital recorder, unless otherwise approved by the District Manager. The test interval for each BOP system component must be 5 minutes, except for coiled tubing operations, which must include a 10 minute high-pressure test for the coiled tubing string. Your representative at the facility must certify that the charts are correct.

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

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

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

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

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

(h) Stump test a subsea BOP system before installation. You must use water to conduct this test. You may use drilling or completion fluids to conduct subsequent tests of a subsea BOP system. You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. You must:

(1) Test all ROV intervention functions on your subsea BOP stack during the stump test. Each ROV must be fully compatible with the BOP stack ROV intervention panels. You must also test and verify closure of at least one set of rams during the initial test on the seafloor through an ROV hot stab. You must submit test procedures, including how you will test each ROV function, with your APM for BSEE District Manager approval. You must:

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

(ii) Notify the appropriate BSEE District Manager a minimum of 72 hours prior to the stump test and initial test on the seafloor;

(iii) Document all your test results and make them available to BSEE upon request; and

(2) Function test autoshear and deadman systems on your subsea BOP stack during the stump test. You must also test the deadman system and verify closure of at least one set of blind-shear rams during the initial test on the seafloor. When you conduct the initial deadman system test on the seafloor you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. You must:

(i) Submit test procedures with your APM for BSEE District Manager approval. The procedures for these function tests must include documentation of the controls and circuitry of the system utilized during each test. The procedure must also describe how the ROV will be utilized during this operation.

(ii) Document the results of each test and make them available to BSEE upon request.

[76 FR 64462, Oct. 18, 2011. Redesignated and amended at 77 FR 50895, 50896, Aug. 22, 2012]

§ 250.618 What are my BOP inspection and maintenance requirements?

(a) *BOP inspections*. (1) You must inspect your BOP system to ensure that the equipment functions properly. The BOP inspections must meet or exceed the provisions of Sections 17.10 and 18.10, Inspections, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.10 and 18.10 described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

(2) 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. The BSEE District Manager may approve alternate methods and frequencies to inspect a marine riser.

(b) *BOP maintenance*. You must maintain your BOP system to ensure that the equipment functions properly. The BOP maintenance must meet or exceed the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells (incorporated by reference as specified in § 250.198). You must document how you met or exceeded the provisions of Sections 17.11 and 18.11, Maintenance; and Sections 17.12 and 18.12, Quality Management, described in API RP 53, the procedures used, record the results, and make the records available to BSEE upon request. You must maintain your records on the rig for 2 years from the date the records are created, or for a longer period if directed by BSEE.

[77 FR 50896, Aug. 22, 2012]

§ 250.619 Tubing and wellhead equipment.

The lessee shall comply with the following requirements during well-workover operations with the tree removed:

(a) No tubing string shall be placed in service or continue to be used unless such tubing string has the necessary strength and pressure integrity and is otherwise suitable for its intended use.

(b) In the event of prolonged operations such as milling, fishing, jarring, or washing over that could damage the casing, the casing shall be pressure tested, calipered, or otherwise evaluated every 30 days and the results submitted to the District Manager.

(c) When reinstalling the tree, you must:

(1) Equip wells to monitor for casing pressure according to the following chart:

If you have . . .	you must equip . . .	so you can monitor . . .
(i) fixed platform wells,	the wellhead,	all annuli (A, B, C, D, *etc.,* annuli).
(ii) subsea wells,	the tubing head,	the production casing annulus (A annulus).

If you have . . .	you must equip . . .	so you can monitor . . .
(iii) hybrid* wells,	the surface wellhead,	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

*Characterized as a well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger, and a surface christmas tree.

(2) Follow the casing pressure management requirements in subpart E of this part.

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. The tree shall be equipped with a minimum of one master valve and one surface safety valve in the vertical run of the tree when it is reinstalled.

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

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

§250.620 Wireline operations.

The lessee shall comply with the following requirements during routine, as defined in §250.601 of this part, and nonroutine wireline workover operations:

(a) Wireline operations shall be conducted so as to minimize leakage of well fluids. Any leakage that does occur shall be contained to prevent pollution.

(b) All wireline perforating operations and all other wireline operations where communication exists between the completed hydrocarbon-bearing zone(s) and the wellbore shall use a lubricator assembly containing at least one wireline valve.

(c) When the lubricator is initially installed on the well, it shall be successfully pressure tested to the expected shut-in surface pressure.

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

Subpart G [Reserved]

Subpart H—Oil and Gas Production Safety Systems

§250.800 General requirements.

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

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

(1) Comply with API RP 14J (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