

Subpart E—Oil and Gas Well-Completion Operations

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§ 250.500 General requirements.

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

§ 250.501 Definition.

When used in this subpart, the following term shall have the meaning given below:

Well-completion operations means the work conducted to establish the production of a well after the production-casing string has been set, cemented, and pressure-tested.

§ 250.502 Equipment movement.

The movement of well-completion rigs and related equipment on and off a platform or from well to well on the same platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving well-completion rigs and related equipment, unless otherwise approved by the District Manager. A closed surface-controlled subsurface safety valve of the pump-through type may be used in lieu of the pump-through-type tubing plug, provided that the surface control has been locked out of operation. The well from which the rig or related equipment is to be moved shall also be equipped with a back-pressure valve prior to removing the blowout preventer (BOP) system and installing the tree.

§ 250.503 Emergency shutdown system.

When well-completion operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an emergency shutdown system (ESD) manually controlled station shall be installed near the driller's console or well-servicing unit operator's work station.

§ 250.504 Hydrogen sulfide.

When a well-completion operation is conducted in zones known to contain hydrogen sulfide (H₂ S) or in zones where the presence of H₂ S is unknown (as defined in § 250.490 of this part), the lessee shall take appropriate precautions to protect life and property on the

platform or completion unit, including, but not limited to operations such as blowing the well down, dismantling wellhead equipment and flow lines, circulating the well, swabbing, and pulling tubing, pumps, and packers. The lessee shall comply with the requirements in § 250.490 of this part as well as the appropriate requirements of this subpart.

§ 250.505 Subsea completions.

No subsea well completion shall be commenced until the lessee obtains written approval from the District Manager in accordance with § 250.513 of this part. That approval shall be based upon a case-by-case determination that the proposed equipment and procedures will adequately control the well and permit safe production operations.

§ 250.506 Crew instructions.

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

§§ 250.507-250.508 [Reserved]

§ 250.509 Well-completion structures on fixed platforms.

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

§ 250.510 Diesel engine air intakes.

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

§ 250.511 Traveling-block safety device.

All units being used for well-completion operations that have

both a traveling block and a crown block must be equipped with a safety device that is designed to prevent the traveling block from striking the crown block. The device must be checked for proper operation weekly and after each drill-line slipping operation. The results of the operational check must be entered in the operations log.

§ 250.512 Field well-completion rules.

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

§ 250.513 Approval and reporting of well-completion operations.

(a) No well-completion operation may begin until the lessee receives written approval from the District Manager. If completion is planned and the data are available at the time you submit the Application for Permit to Drill and Supplemental APD Information Sheet (Forms BSEE-0123 and BSEE-0123S), you may request approval for a well-completion on those forms (see §§ 250.410 through 250.418 of this part). If the District Manager has not approved the completion or if the completion objective or plans have significantly changed, you must submit an Application for Permit to Modify (Form BSEE-0124) for approval of such operations.

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

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

(2) A schematic drawing of the well showing the proposed producing zone(s) and the subsurface well-completion equipment to be used;

(3) For multiple completions, a partial electric log showing the zones proposed for completion, if logs have not been previously submitted;

(4) All applicable information required in § 250.515.

(5) When the well-completion is in a zone known to contain H₂ S or a zone where the presence of H₂ S is unknown, information pursuant to § 250.490 of this part; and

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

(c) Within 30 days after completion, you must submit to the District Manager an End of Operations Report (Form BSEE-0125), including a schematic of the tubing and subsurface equipment.

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

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

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

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

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

- (1) A fill-up line above the uppermost BOP;
- (2) A well-control, fluid-volume measuring device for determining fluid volumes when filling the hole on trips; and
- (3) A recording mud-pit-level indicator to determine mud-pit-volume gains and losses. This indicator shall include both a visual and an audible warning device.

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

(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.

§ 250.515 What BOP information must I submit?

For completion 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 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; and

(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.

§ 250.516 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure rating of the BOP system and BOP system components shall exceed the expected surface pressure to which they may be subjected. If the expected surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with Form BSEE-0124 or Form BSEE-0123, as appropriate, a well-control procedure that indicates how the annular preventer will be utilized, and the pressure limitations that will be applied during each mode of pressure control.

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

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

	set of variable bore rams for two sets of pipe rams.
(5) You use a subsea BOP stack,	The requirements in § 250.442(a) of this part.

(c) The BOP systems for well completions must be equipped with the following:

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

(2) A secondary power source, independent from the primary power source, with sufficient capacity to close all BOP system components and hold them closed.

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

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

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

(d) An inside BOP or a spring-loaded, back-pressure safety valve and an essentially full-opening, work-string safety valve in the open position shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting valves in the work string.

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

§ 250.517 Blowout preventer system tests, inspections, and maintenance.

(a) *BOP pressure testing timeframes.* You must pressure test your BOP system:

(1) When installed; and

(2) Before 14 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before 12 a.m. (midnight) on the 14th day following the conclusion of the previous test. However, the District Manager may require testing every 7 days if conditions or BOP performance warrant.

(b) *BOP test pressures.* When you test the BOP system, you must conduct a low pressure and a high pressure test for each BOP component. Each individual pressure test must hold pressure long enough to demonstrate that the tested component(s) holds the required pressure. The District Manager may approve or require other test pressures or practices. Required test pressures are as follows:

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

(2) For ram-type BOP's, choke manifold, and other BOP equipment, the high pressure test must equal the rated working pressure of the equipment.

(3) For annular-type BOP's, the high pressure test must equal 70 percent of the rated working pressure of the equipment.

(c) *Duration of pressure test.* Each test must hold the required pressure for 5 minutes.

(1) For surface BOP systems and surface equipment of a subsea BOP system, a 3-minute test duration is acceptable if you record your test pressures on the outermost half of a 4-hour chart, on a 1-hour chart, or on a digital recorder.

(2) If the equipment does not hold the required pressure during a test, you must remedy the problem and retest the affected component(s).

(d) Additional BOP testing requirements. You must:

(1) Use water to test the surface BOP system;

(2) Stump test a 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.

(3) Alternate tests between control stations and pods. If a control station or pod is not functional, you must suspend further completion operations until that station or pod is operable;

(4) Pressure test the blind or blind-shear ram at least every 30 days;

(5) Function test annulars and rams every 7 days;

(6) Pressure-test variable bore-pipe rams against all sizes of pipe in use, excluding drill collars and bottom-hole tools;

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

(8) 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

(9) 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 all your test results and make them available to BSEE upon request.

(e) *Postponing BOP tests.* You may postpone a BOP test if you have well-control problems. You must conduct the required BOP test as soon as possible (*i.e.*, first trip out of the hole) after the problem has been remedied. You must record the reason for postponing any test in the driller's report.

(f) *Weekly crew drills.* You must conduct a weekly drill to familiarize all personnel engaged in well-completion operations with appropriate safety measures.

(g) *BOP inspections.* (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.

(h) *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.

(i) *BOP test records.* You must record the time, date, and results of all pressure tests, actuations, crew drills, and inspections of the BOP system, system components, and marine riser in the driller's report. In addition, you must:

- (1) Record BOP test pressures on pressure charts;
- (2) Have your onsite representative certify (sign and date) BOP test charts and reports as correct;
- (3) Document the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. You may reference a BOP test plan if it is available at the facility;
- (4) Identify the control station or pod used during the test;
- (5) Identify any problems or irregularities observed during BOP system and equipment testing and record actions taken to remedy the problems or irregularities;
- (6) Retain all records including pressure charts, driller's report,

and referenced documents pertaining to BOP tests, actuations, and inspections at the facility for the duration of the completion activity; and

(7) After completion of the well, you must retain all the records listed in paragraph (i)(6) of this section for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Manager.

(j) *Alternate methods.* The District Manager may require, or approve, more frequent testing, as well as different test pressures and inspection methods, or other practices.

§ 250.518 Tubing and wellhead equipment.

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

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

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

If you . . .	you must equip . . .	so you can monitor . . .
(1) fixed platform wells,	the wellhead,	all annuli (A, B, C, D, <i>etc.</i> ,annuli).
(2) subsea wells,	the tubing head,	the production casing annulus (A annulus).
(3) hybrid * wells,	the surface wellhead,	all annuli at the surface (A and B riser annuli). If the production casing below the mudline and the production casing riser above the mudline are pressure isolated from each other, provisions must be made to monitor the production casing below the mudline for casing pressure.

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

(d) Wellhead, tree, and related equipment shall have a pressure rating greater than the shut-in tubing pressure and shall be designed, installed, used, maintained, and tested so as to achieve and maintain pressure control. New wells completed as flowing or gas-lift wells

shall be equipped with a minimum of one master valve and one surface safety valve, installed above the master valve, in the vertical run of the tree.

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

Casing Pressure Management

§ 250.519 What are the requirements for casing pressure management?

Once you install your wellhead, you must meet the casing pressure management requirements of API RP 90 (as incorporated by reference in § 250.198) and the requirements of §§ 250.519 through 250.530. If there is a conflict between API RP 90 and the casing pressure requirements of this subpart, you must follow the requirements of this subpart.

§ 250.520 How often do I have to monitor for casing pressure?

You must monitor for casing pressure in your well according to the following table:

If you have . . .	you must monitor . . .	with a minimum one pressure data point recorded per . . .
(a) fixed platform wells,	monthly,	month for each casing.
(b) subsea wells,	continuously,	day for the production casing.
(c) hybrid wells,	continuously,	day for each riser and/or the production casing.
(d) wells operating under a casing pressure request on a manned fixed platform,	daily,	day for each casing.
(e) wells operating under a casing pressure request on an unmanned fixed platform,	weekly,	week for each casing.

§ 250.521 When do I have to perform a casing diagnostic test?

(a) You must perform a casing diagnostic test within 30 days after first observing or imposing casing pressure according to the following table:

If you have a	you must perform a casing diagnostic test if . . .
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...	
(1) fixed platform well,	the casing pressure is greater than 100 psig.
(2) subsea well,	the measurable casing pressure is greater than the external hydrostatic pressure plus 100 psig measured at the subsea wellhead.
(3) hybrid well,	a riser or the production casing pressure is greater than 100 psig measured at the surface.

(b) You are exempt from performing a diagnostic pressure test for the production casing on a well operating under active gas lift.

§ 250.522 How do I manage the thermal effects caused by initial production on a newly completed or recompleted well?

A newly completed or recompleted well often has thermal casing pressure during initial startup. Bleeding casing pressure during the startup process is considered a normal and necessary operation to manage thermal casing pressure; therefore, you do not need to evaluate these operations as a casing diagnostic test. After 30 days of continuous production, the initial production startup operation is complete and you must perform casing diagnostic testing as required in §§ 250.520 and 250.522.

§ 250.523 When do I have to repeat casing diagnostic testing?

Casing diagnostic testing must be repeated according to the following table:

When . . .	you must repeat diagnostic testing . . .
(a) your casing pressure request approved term has expired,	immediately.
(b) your well, previously on gas lift, has been shut-in or returned to flowing status without gas lift for more than 180 days,	immediately on the production casing (A annulus). The production casing (A annulus) of wells on active gas lift are exempt from diagnostic testing.
(c) your casing pressure request becomes invalid,	within 30 days.
(d) a casing or riser has an increase in pressure greater than 200 psig over the previous casing diagnostic test,	within 30 days.
(e) after any corrective action has	within 30 days.

been taken to remediate undesirable casing pressure, either as a result of a casing pressure request denial or any other action,	
(f) your fixed platform well production casing (A annulus) has pressure exceeding 10 percent of its minimum internal yield pressure (MIYP), except for production casings on active gas lift,	once per year, not to exceed 12 months between tests.
(g) your fixed platform well's outer casing (B, C, D, etc., annuli) has a pressure exceeding 20 percent of its MIYP,	once every 5 years, at a minimum.

§ 250.524 How long do I keep records of casing pressure and diagnostic tests?

Records of casing pressure and diagnostic tests must be kept at the field office nearest the well for a minimum of 2 years. The last casing diagnostic test for each casing or riser must be retained at the field office nearest the well until the well is abandoned.

§ 250.525 When am I required to take action from my casing diagnostic test?

You must take action if you have any of the following conditions:

- (a) Any fixed platform well with a casing pressure exceeding its maximum allowable wellhead operating pressure (MAWOP);
- (b) Any fixed platform well with a casing pressure that is greater than 100 psig and that cannot bleed to 0 psig through a 1/2 -inch needle valve within 24 hours, or is not bled to 0 psig during a casing diagnostic test;
- (c) Any well that has demonstrated tubing/casing, tubing/riser, casing/casing, riser/casing, or riser/riser communication;
- (d) Any well that has sustained casing pressure (SCP) and is bled down to prevent it from exceeding its MAWOP, except during initial startup operations described in § 250.521;
- (e) Any hybrid well with casing or riser pressure exceeding 100 psig; or
- (f) Any subsea well with a casing pressure 100 psig greater than the external hydrostatic pressure at the subsea wellhead.

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

Within 14 days after you perform a casing diagnostic test requiring action under § 250.524:

You must submit either . . .	to the appropriate . . .	and it must include . . .	You must also . . .
(a) a notification of corrective action; or,	District Manager and copy the Regional Supervisor, Field Operations,	requirements under § 250.526,	submit an Application for Permit to Modify or Corrective Action Plan within 30 days of the diagnostic test.
(b) a casing pressure request,	Regional Supervisor, Field Operations,	requirements under § 250.527.	

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

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

- (a) Lessee or Operator name;
- (b) Area name and OCS block number;
- (c) Well name and API number; and
- (d) Casing diagnostic test data.

§ 250.528 What must I include in my casing pressure request?

The following information must be included in the casing pressure request:

- (a) API number;
- (b) Lease number;
- (c) Area name and OCS block number;
- (d) Well number;
- (e) Company name and mailing address;
- (f) All casing, riser, and tubing sizes, weights, grades, and MIYP;
- (g) All casing/riser calculated MAWOPs;
- (h) All casing/riser pre-bleed down pressures;
- (i) Shut-in tubing pressure;
- (j) Flowing tubing pressure;
- (k) Date and the calculated daily production rate during last well test (oil, gas, basic sediment, and water);
- (l) Well status (shut-in, temporarily abandoned, producing, injecting, or gas lift);

- (m) Well type (dry tree, hybrid, or subsea);
- (n) Date of diagnostic test;
- (o) Well schematic;
- (p) Water depth;
- (q) Volumes and types of fluid bled from each casing or riser evaluated;
- (r) Type of diagnostic test performed:
 - (1) Bleed down/buildup test;
 - (2) Shut-in the well and monitor the pressure drop test;
 - (3) Constant production rate and decrease the annular pressure test;
 - (4) Constant production rate and increase the annular pressure test;
 - (5) Change the production rate and monitor the casing pressure test; and
 - (6) Casing pressure and tubing pressure history plot;
- (s) The casing diagnostic test data for all casing exceeding 100 psig;
- (t) Associated shoe strengths for casing shoes exposed to annular fluids;
- (u) Concentration of any H₂ S that may be present;
- (v) Whether the structure on which the well is located is manned or unmanned;
- (w) Additional comments; and
- (x) Request date.

§ 250.529 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.

§ 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).

§ 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.