(3) A description of how you met the design requirements, load cases, and allowable stresses for each load case according to API RP 2RD (as incorporated by reference in § 250.198);

(4) Detailed information regarding the tether system used to connect the FSHR to a buoyancy air can;

(5) Descriptions of your monitoring system and monitoring plan to monitor the pipeline FSHR and tether for fatigue, stress, and any other abnormal condition (*e.g.*, corrosion) that may negatively impact the riser or tether; and

(6) Documentation that the tether system and connection accessories for the pipeline FSHR have been certified by an approved classification society or equivalent and verified by the CVA required in Subpart I; and

* * * * *

8. Revise § 250.400 to read as follows:

Subpart D—Oil and Gas Drilling Operations

§ 250.400 General Requirements.

Drilling operations must be conducted in a safe manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS), including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.

§§ 250.401 through 250.403 [Reserve]

9. Remove and reserve §§ 250.401 through 250.403.

§ 250.406 [Reserve]

10. Remove and reserve § 250.406.

11. Revise § 250.411 to read as follows:

§ 250.411 What information must I submit with my application?

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

Information that you must include with an APD	Where to find a description
(a) Plat that shows locations of the proposed well,	§ 250.412.
(b) Design criteria used for the proposed well,	§ 250.413.
(c) Drilling prognosis,	§ 250.414.
(d) Casing and cementing programs,	§ 250.415.
(e) Diverter systems descriptions,	§ 250.416.
(f) BOP system descriptions,	§ 250.731.
(g) Requirements for using a MODU, and	§ 250.713.
(h) Additional information.	§ 250.418.

12. In § 250.413, revise paragraph (g) to read as follows:

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

* * * * *

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

* * * * *

13. Amend § 250.414 by:

a. Revising paragraphs (c), (h), and (i); and

b. Adding paragraphs (j) and (k) to read as follows:

§ 250.414 What must my drilling prognosis include?

* * * * *

(c) Planned safe drilling margin that is between the estimated pore pressure and the lesser of estimated fracture gradients or casing shoe pressure integrity test and that is based on a risk assessment consistent with expected well conditions and operations.

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

(i) greater than the estimated pore pressure, and

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

(2) In lieu of meeting the criteria in paragraph (1)(ii), you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight.

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

* * * * *

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

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

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

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

14. In § 250.415, revise paragraph (a) to read as follows:

§ 250.415 What must my casing and cementing programs include?

* * * * *

(a) The following well design information:

(1) Hole sizes;

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

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

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

* * * * *

15. Revise § 250.416 to read as follows:

§ 250.416 What must I include in the diverter description?

You must include in the diverter description:

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

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

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

(2) Spool outlet internal diameter(s);

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

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

§ 250.417 [Reserve]

16. Remove and reserve § 250.417.

17. In § 250.418, remove paragraph (i), redesignate paragraph (j) as paragraph (i), revise paragraphs (g) and (h) to read as follows:

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

* * * * *

(g) A request for approval, if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

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

* * * * *

18. Amend § 250.420 by:

a. Revising the introductory text and paragraph (a)(5);

b. Redesignating paragraph (a)(6) as (a)(7);

c. Adding new paragraph (a)(6) and paragraph (b)(4); and

d. Revising paragraph (c) to read as follows:

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

You must case and cement all wells. Your casing and cementing programs must meet the applicable requirements of this subpart and of subpart G.

(a) * * *

(5) Support unconsolidated sediments;

(6) Provide adequate centralization to ensure proper cementation; and

* * * * *

(b) * * *

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

* * * * *

(c) *Cementing requirements.*

(1) You must design and conduct your cementing jobs so that cement composition, placement techniques, and waiting times ensure that the cement placed behind the bottom 500 feet of casing attains a minimum compressive strength of 500 psi before drilling out the casing or before commencing completion operations. (If a liner is used refer to § 250.421(f)).

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

19. In § 250.421, revise paragraphs (b) and (f) to read as follows:

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

*   *   *   *   *

Casing type	Casing requirements	Cementing requirements
* * * * * * *		
(b) Conductor	Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone.	Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager.
* * * * * * *		
(f) Liners	If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner.	Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing. If you have a liner lap and are unable to cement 500 feet above the previous shoe, as provided by (d) and (e), you must submit and receive approval from the District Manager on a case-by-case basis.

20. Revise § 250.423 to read as follows:

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

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

(a) You must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the casing string. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

(b) If you run a liner that has a latching mechanism or lock down mechanism, you must ensure that the latching mechanisms or lock down mechanisms are engaged upon successfully installing and cementing the liner. If there is an indication of an inadequate cement job, you must comply with § 250.428(c).

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

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

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

§§ 250.424 through 250.426 [Reserve]

21. Remove and reserve §§ 250.424 through 250.426.

22. In § 250.427, revise paragraph (b) to read as follows:

§ 250.427 What are the requirements for pressure integrity tests?

* * * * *

(b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

23. Amend § 250.428 by:

a. Revising paragraphs (b) through (d); and

b. Adding paragraph (k) to read as follows:

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

* * * * *

If you encounter the following situation:	**Then you must…**
* * * * * * *	
(b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations,	Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.
(c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment),	(1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
(d) Inadequate cement job,	Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.
* * * * * * *	
(k) Plan to use a valve(s) on the drive pipe during cementing operations for the conductor casing, surface casing, or liner,	Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must

	contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

§§ 250.440 through 250.451 [Reserve]

24. Remove the undesignated center heading "Blowout Preventer (BOP) System Requirements" and remove and reserve §§ 250.440 through 250.451.

§ 250.456 [Amended]

25. Amend § 250.456:

a. In paragraph (i), by adding the word "and" after the semi-colon

b. By removing paragraph (j); and

c. By redesignating paragraph (k) as (j).

26. Revise § 250.462 to read as follows.

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

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

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

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

(2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation

indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.

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

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

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

(3) Collocated equipment including dispersant injection equipment;

(4) Riser systems;

(5) Remotely operated vehicles (ROVs);

(6) Capture vessels;

(7) Support vessels; and

(8) Storage facilities.

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

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

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

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

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

(1) Well design changes, or

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

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

Equipment	Requirements, you must:	Additional information
(1) Capping stacks,	(i) Function test all pressure containing critical components on a quarterly frequency (not to exceed 104 days between tests),	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in after being functioned.
	(ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and a BSEE- approved verification organization.	Pressure containing critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: all blind rams, wellhead connectors, and outlet valves.
	(iii) Notify BSEE at least 21 days prior to commencing any pressure testing.	
(2) Production safety systems used for flow and capture operations,	(i) Meet or exceed the requirements set forth in §§ 250.800-250.808 of this part, excluding required equipment that would be installed below the wellhead or that is not applicable	

	to the cap and flow system.	
	(ii) Have all equipment unique to containment operations available for inspection at all times.	
(3) Subsea utility equipment,	Have all referenced containment equipment available for inspection at all times.	Subsea utility equipment includes, but is not limited to: hydraulic power sources, debris removal, and hydrate control equipment.
(4) Collocated equipment,	Have equipment available for inspection at all times.	Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.

27. In § 250.465, revise paragraph (b)(3) to read as follows:

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

* * * * *

(b) * * *

(3) Within 30 days after completing this work, you must submit an End of Operations Report (EOR), Form BSEE–0125, as required under § 250.744.

§§ 250.466 through 250.469 [Reserve]

28. Remove and reserve §§ 250.466 through 250.469.

29. Revise § 250.500 to read as follows:

Subpart E—Oil and Gas Well-Completion Operations

§ 250.500 General requirements.

Well-completion operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the OCS, including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of Subpart G.

§§ 250.502 and 250.506 [Reserve]

30. Remove and reserve §§ 250.502 and 250.506.

§ 250.514 [Amended]

31. In § 250.514, remove paragraph (d).

§§ 250.515 through 250.517 [Reserve]

32. Remove and reserve §§ 250.515 through 250.517.

33. Amend § 250.518 by:

a. Removing paragraph (b);

b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

c. Adding new paragraph (e) and paragraph (f) to read as follows:

§ 250.518 Tubing and wellhead equipment.

* * * * *

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

(1) All permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

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

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

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

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

34. Revise § 250.600 to read as follows:

Subpart F—Oil and Gas Well-Workover Operations

§ 250.600 General requirements.

Well-workover operations must be conducted in a manner to protect against harm or damage to life (including fish and other aquatic life), property, natural resources of the Outer Continental Shelf (OCS) including any mineral deposits (in areas leased and not leased), the National security or defense, or the marine, coastal, or human environment. In addition to the requirements of this subpart, you must also follow the applicable requirements of subpart G.

§ 250.602 [Reserve]

35. Remove and reserve § 250.602.

§ 250.606 [Reserve]

36. Remove and reserve § 250.606.

§ 250.614 [Amended]

37. In § 250.614, remove paragraph (d).

§ 250.615 [Reserve]

38. Remove and reserve § 250.615.

39. Amend § 250.616 by:

a. Revising the section heading;

b. Removing paragraphs (a) through (e); and

c. Redesignating paragraphs (f) through (h) as paragraphs (a) through (c) to read as follows:

§ 250.616 Coiled tubing and snubbing operations.

* * * * *

§§ 250.617 and 250.618 [Reserve]

40. Remove and reserve §§ 250.617 and 250.618.

41. Amend § 250.619 by:

a. Removing paragraph (b);

b. Redesignating paragraphs (c) through (e) as paragraphs (b) through (d); and

c. Adding new paragraphs (e) and (f) to read as follows:

§ 250.619 Tubing and wellhead equipment.

* * * * *

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

(1) All permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

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

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

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

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

42. Add subpart G to read as follows:

Subpart G—Well Operations and Equipment

General Requirements

Sec.

Rig Requirements

Well Operations

250.720 When and how must I secure a well?

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

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

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

250.724 What are the real-time monitoring requirements?

Blowout Preventer (BOP) System Requirements

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

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

250.732 What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?

250.733 What are the requirements for a surface BOP stack?

250.734 What are the requirements for a subsea BOP system?

250.735 What associated systems and related equipment must all BOP systems include?

Subpart G—Well Operations and Equipment

General Requirements

§ 250.700 What operations and equipment does this subpart cover?

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

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

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

§ 250.702 May I obtain departures from these requirements?

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

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

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

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

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

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

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

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

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

Rig Requirements

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

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

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

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

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

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

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

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

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

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

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

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

§ 250.712 What rig unit movements must I report?

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

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

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

(3) The departure of a rig unit from the location.

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

(c) If a MODU or platform rig is to be warm or cold stacked, you must inform the District Manager:

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

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

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

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

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

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

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

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

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

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

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

(c) *For frontier areas*. (1) If the design of the MODU you plan to use in a frontier area is unique or has not been proven for use in the proposed environment, the District Manager may require you to submit a third-party review of the MODU design. If required, you must obtain a third-party review of your MODU similar to the process outlined in §§ 250.915 through 250.918. You may submit this information before submitting an APD or APM.

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

(d) *Additional documentation.* You must provide the current Certificate of Inspection (for U.S.- flag vessels) or Certificate of Compliance (for foreign-flag vessels) from the USCG and Certificate of Classification. You must also provide current documentation of any operational limitations imposed by an appropriate classification society.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) MODU name;

(3) Initial date and time; and

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

Well Operations

§ 250.720 When and how must I secure a well?

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

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

(i) Evacuation of the rig crew;

(ii) Inability to keep the rig on location;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to re-cement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

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

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

(2) You must perform a negative pressure test prior to unlatching the BOP at any point in the well. The negative pressure test must be performed on those components, at

a minimum, that will be exposed to the negative differential pressure that will occur when the BOP is disconnected.

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

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

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

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

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

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

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

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

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

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

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

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

(2) Report the results of your evaluation to the District Manager and obtain approval of those results before resuming operations. Your report must include calculations that show the well's integrity is above the minimum safety factors, if an imaging tool or caliper is used.

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

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

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

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

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

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

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

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

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

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

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

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

(d) All wells in the same well-bay which are capable of producing hydrocarbons must be shut-in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving rig units and related equipment, unless otherwise approved by the District Manager.

(1) A closed surface-controlled subsurface safety valve of the pump-through-type may be used in lieu of the pump-through-type tubing plug provided that the surface control has been locked out of operation.

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

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

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

§ 250.724 What are the real-time monitoring requirements?

(a) No later than [INSERT DATE 3 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER], when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an HPHT environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following:

(1) The BOP control system;

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

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

(b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c). Onshore personnel who monitor real-time data must have the capability to contact rig personnel during operations. After operations, you must preserve and store these data onshore for recordkeeping purposes as required in §§ 250.740 and 250.741. You must provide BSEE with access to your designated real-time monitoring data onshore upon request. You must include in your APD a certification that you have a real-time monitoring plan that meets the criteria in paragraph (c).

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

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

(2) A description of how your real-time monitoring data will be transmitted onshore during operations, how the data will be labeled and monitored by qualified onshore personnel, and how it will be stored onshore;

(3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring data including, if applicable, the location of any onshore data monitoring or data storage facilities;

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

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

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

offshore communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.

Blowout Preventer (BOP) System Requirements

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

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

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

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

(i) ANSI/API Spec. 6A;

(ii) ANSI/API Spec. 16A;

(iii) ANSI/API Spec. 16C;

(iv) API Spec. 16D; and

(v) ANSI/API Spec. 17D.

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

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

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

(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and:

(1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and the manufacturer of such equipment within 30 days

after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.

(2) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report.

(3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs.

(4) You must send the reports required in this paragraph to: Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement;, 45600 Woodland Road, Sterling, VA 20166.

(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

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

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

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

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

You must submit:	**Including:**
(a) A complete description of the BOP system and system components,	(1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations);

	(8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes).
(b) Schematic drawings,	(1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled, including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.
(c) Certification by a BSEE-approved verification organization (BAVO),	Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system.
(d) Additional certification by a BAVO, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility,	Verification that: (1) The BOP stack is designed and suitable 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; and (3) The BOP stack will operate in the conditions in which it will be used.
(e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems,	A listing of the functions with their sequences and timing.
(f) Certification stating that the MIA Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	

§ 250.732 What are the BSEE-approved verification organization (BAVO) requirements for BOP systems and system components?

(a) BSEE will maintain a list of BSEE-approved verification organizations (BAVOs) on its public website that you must use to satisfy any provision in this subpart that requires a BAVO certification, verification, report, or review. You must comply with all requirements in this subpart for BAVO certification, verification, or reporting no later than 1 year from the date BSEE publishes a list of BAVOs.

(1) Until such time as you use a BAVO to perform the actions that this subpart requires to be performed by a BAVO, but not after 1 year from the date BSEE publishes a list of BAVOs, you must use an independent third-party meeting the criteria specified in paragraph (a)(2) to prepare certifications, verifications, and reports as required by §§ 250.731(c) - (d), 250.732 (b) - (c), 250.734(b)(1), 250.738(b)(4), and 250.739(b).

(2) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the certifications, verifications, and reports required under paragraph (a)(1).

(3) For an organization to become a BAVO, it must submit the following information to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

(i) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;

(ii) Technical capabilities;

(iii) Size and type of organization;

(iv) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;

(v) Ability to perform the verification functions for projects considering current commitments;

(vi) Previous experience with BSEE requirements and procedures; and

(vii) Any additional information that may be relevant to BSEE's review.

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

You must submit verification and documentation related to:	**That:**
(1) Shear testing,	(i) Demonstrates that the BOP will shear the drill pipe and any electric-, wire-, and slick-line to be used in the well, no later than [INSERT DATE 2 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER]; (ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards; (iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe; (iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism as required in § 250.734(a)(16); (v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and (vi) Includes relevant testing results.
(2) Pressure integrity testing, and	(i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the RWP of the BOP for 30 minutes; and (iii) Includes all relevant test results.
(3) Calculations.	Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP.

(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BAVO that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BAVO access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment.

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

(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BAVO. You must submit this report to the Chief, Office of Offshore Regulatory

Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166. This report must include:

(1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.

(2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.

(3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.

(4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.

(5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.

(6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and any applicable OEM requirements.

(7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.

(8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

(9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.

(10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.

(11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.

(12) Verification that any inspection, maintenance, or repair work meets the manufacturer’s design and material specifications.

(13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.

(14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

(e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

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

(a) When you drill or conduct operations with a surface BOP stack, you must install the BOP system before drilling or conducting operations to deepen the well below the surface casing and after the well is deepened below the surface casing point. The surface

BOP stack must include at least four remote-controlled, hydraulically operated BOPs, consisting of one annular BOP, one BOP equipped with blind shear rams, and two BOPs equipped with pipe rams.

(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to [INSERT DATE 2 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER], and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.

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

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

(1) For BOPs installed after [INSERT DATE 3 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER], follow the BOP requirements in § 250.734(a)(1).

(2) For risers installed after [INSERT DATE 90 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER], use a dual bore riser configuration before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to

the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198), including appropriate design for the maximum anticipated operating and environmental conditions.

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

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

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

(d) You must install a choke and a kill line on the BOP stack. You must equip each line with two full-bore, full-opening valves, one of which must be remote-controlled. On the kill line, you may install a check valve and a manual valve instead of the remote-controlled valve. To use this configuration, both manual valves must be readily accessible and you must install the check valve between the manual valves and the pump.

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

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

When operating with a subsea BOP system, you must:	Additional requirements
(1) Have at least five remote-controlled, hydraulically operated BOPs;	You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the dual ram requirement, you must comply with this requirement no later than [INSERT DATE 5 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER]. (i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, except tubing with exterior control lines and flat packs, a bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools. (ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to [INSERT DATE 2 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER], appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole no later than [INSERT DATE 2 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER]; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).
(2) Have an operable redundant pod control system to ensure proper and independent operation of the BOP system;	
(3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface;	The accumulator capacity must: (i) Operate each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function *i.e.*, flying leads. (iii) No later than [INSERT DATE 5 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER] have bottles for the autoshear, and deadman that are dedicated to, but may be shared between, those functions. (iv) Perform under MASP conditions as defined for the operation.
(4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention	The ROV must be capable of opening and closing each shear ram, ram locks, one pipe ram, and

capability;	LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).
(5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must examine all ROV-related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;	The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.
(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs;	(i) *Autoshear system* means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a *rapid discharge* system. (ii) *Deadman system* means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a *rapid discharge* system. (iii) *Emergency Disconnect Sequence (EDS) system* means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a *rapid discharge* system. (iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing its expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum sealing efficiency. (vi) The control system for the emergency functions must be a fail-safe design once activated.
(7) Demonstrate that any acoustic control system will function in the proposed environment and conditions;	If you choose to use an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic control system will function in the proposed environment and conditions. The District Manager may require additional information as appropriate to clarify or evaluate the acoustic control system information provided in your demonstration.
(8) Have operational or physical barrier(s) on BOP control panels to prevent accidental disconnect	You must incorporate enable buttons, or a similar feature, on control panels to ensure two-

functions;	handed operation for all critical functions.
(9) Clearly label all control panels for the subsea BOP system;	Label other BOP control panels, such as hydraulic control panel.
(10) Develop and use a management system for operating the BOP system, including the prevention of accidental or unplanned disconnects of the system;	The management system must include written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
(11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;	Personnel must have: (i) Training in deepwater well-control theory and practice according to the requirements of Subparts O and S; and (ii) A comprehensive knowledge of BOP hardware and control systems.
(12) Before removing the marine riser, displace the fluid in the riser with seawater;	You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).
(13) Install the BOP stack in a well cellar when in an ice-scour area;	Your well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(14) Install at least two side outlets for a choke line and two side outlets for a kill line;	(i) If your stack does not have side outlets, you must install a drilling spool with side outlets. (ii) Each side outlet must have two full-bore, full-opening valves. (iii) The valves must hold pressure from both directions and must be remote-controlled. (iv) You must install a side outlet below the lowest sealing shear ram. You may have a pipe ram or rams between the shearing ram and side outlet.
(15) Install a gas bleed line with two valves for the annular preventer no later than [INSERT DATE 2 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER];	(i) The valves must hold pressure from both directions; (ii) If you have dual annulars, you must install the gas bleed line below the upper annular.
(16) Use a BOP system that has the following mechanisms and capabilities;	(i) A mechanism coupled with each shear ram to position the entire pipe, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism no later than [INSERT DATE 7 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER]; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;

	(iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

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

(1) Submit a revised permit with a verification report from a BAVO documenting the repairs and that the BOP is fit for service;

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

(3) Receive approval from the District Manager.

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

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

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

(a) An accumulator system (as specified in API Standard 53, and incorporated by reference in § 250.198) that provides the volume of fluid capacity (as specified in API

Standard 53, Annex C) necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate the BOP functions as defined in API Standard 53, without assistance from a charging system, and still have a minimum pressure of 200 psi remaining on the bottles above the pre-charge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

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

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

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

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

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

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

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

(2) For surface BOPs,

(i) Remotely-operated locking devices must be installed on blind shear rams no later than [INSERT DATE 3 YEARS AFTER PUBLICATION IN THE FEDERAL REGISTER];

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

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

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

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

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

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

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

(1) The applicable kelly-type valves as described in API Standard 53;

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

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

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

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

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

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

§ 250.737 What are the BOP system testing requirements?

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

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

(1) When installed;

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

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

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

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

You must conduct a…	**According to the following procedures…**
(1) Low-pressure test.	All low-pressure tests must be between 250 and 350 psi. Any initial pressure above 350 psi must be bled back to a pressure between 250 and 350 psi before starting the test. If the initial pressure exceeds 500 psi, you must bleed back to zero and reinitiate the test.
(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components.	The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.
(3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.	The high pressure test must equal 70 percent of the RWP of the equipment or be 500 psi greater than your calculated MASP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.

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

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

You must…	**Additional requirements…**
(1) Follow the testing requirements of API Standard 53 (as incorporated in § 250.198).	If there is a conflict between API Standard 53, testing requirements and this section, you must follow the requirements of this section.
(2) Use water to test a surface BOP system on the initial test. You may use drilling/completion/workover fluids to conduct subsequent tests of a surface BOP system.	(i) You must submit test procedures with your APD or APM for District Manager approval. (ii) Contact the District Manager at least 72 hours prior to beginning the initial test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the initial test results to the appropriate District Manager within 72 hours after completion of the tests.
(3) Stump test a subsea BOP system before installation.	(i) You must use water to conduct this test. You may use drilling/completion/workover fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test. (v) You must follow (b) and (c) of this section.
(4) Perform an initial subsea BOP test.	(i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for

	District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. (vi) You must pressure test the selected rams according to (b) and (c) of this section.
(5) Alternate testing pods between control stations.	(i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly, (B) The control station used for the pressure test must be alternated between pressure tests, and (C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing and 14 day pressure testing. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests and monthly thereafter.
(6) Pressure test variable bore-pipe ram BOPs against pipe sizes according to API Standard 53, excluding the bottom hole assembly that includes heavy-weight pipe or collars and bottom-hole tools.	
(7) Pressure test annular type BOPs against pipe sizes according to API Standard 53.	
(8) Pressure test affected BOP components following the disconnection or repair of any well-pressure containment seal in the wellhead or BOP stack assembly.	
(9) Function test annular and pipe/variable bore ram BOPs every 7 days between pressure tests.	
(10) Function test shear ram(s) BOPs every 14 days.	
(11) Actuate safety valves assembled with proper casing connections before running casing.	
(12) Function test autoshear/deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the	(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event. (ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be

deadman system and verify closure of the shearing rams during the initial test on the seafloor.	utilized during this operation. (iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test. (iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test. (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures. (vi) You must pressure test the blind shear ram(s) according to (b) and (c) of this section. (vii) If a casing shear ram is installed, you must describe how you will verify closure of the ram. (viii) You must document all your test results and make them available to BSEE upon request.

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

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

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

If you encounter the following situation:	Then you must . . .
(a) BOP equipment does not hold the required pressure during a test;	Correct the problem and retest the affected equipment. You must report any problems or irregularities, including any leaks, on the daily report as required in § 250.746.

(b) Need to repair, replace, or reconfigure a surface or subsea BOP system;	(1) First place the well in a safe, controlled condition as approved by the District Manager (*e.g.*, before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. (4) You must submit a report from a BAVO to the District Manager certifying that the BOP is fit for service.
(c) Need to postpone a BOP test due to well-control problems such as lost circulation, formation fluid influx, or stuck pipe;	Record the reason for postponing the test in the daily report and conduct the required BOP test after the first trip out of the hole.
(d) BOP control station or pod that does not function properly;	Suspend operations until that station or pod is operable. You must report any problems or irregularities, including any leaks, to the District Manager.
(e) Plan to operate with a tapered string;	Install two or more sets of conventional or variable-bore pipe rams in the BOP stack to provide for the following: two sets of rams must be capable of sealing around the larger-size drill string and one set of pipe rams must be capable of sealing around the smaller size pipe, excluding the bottom hole assembly that includes heavy weight pipe or collars and bottom-hole tools.
(f) Plan to install casing rams or casing shear rams in a surface BOP stack;	Test the affected connections before running casing to the RWP or MASP plus 500 psi. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.
(g) Plan to use an annular BOP with a RWP less than the anticipated surface pressure;	Demonstrate that your well-control procedures or the anticipated well conditions will not place demands above its RWP and obtain approval from the District Manager.
(h) Plan to use a subsea BOP system in an ice-scour area;	Install the BOP stack in a well cellar. The well cellar must be deep enough to ensure that the top of the stack is below the deepest probable ice-scour depth.
(i) You activate any shear ram and pipe or casing is sheared;	Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.
(j) Need to remove the BOP stack;	Have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager

	may require additional barriers and test(s).
(k) In the event of a deadman or autoshear activation, if there is a possibility of the blind shear ram opening immediately upon re-establishing power to the BOP stack;	Place the blind shear ram opening function in the block position prior to re-establishing power to the stack. Contact the District Manager and receive approval of procedures for re-establishing power and functions prior to latching up the BOP stack or re-establishing power to the stack.
(l) If a test ram is to be used;	The wellhead/BOP connection must be tested to the MASP plus 500 psi for the hole section to which it is exposed. This can be done by: (1) Testing wellhead/BOP connection to the MASP plus 500 psi for the well upon installation; (2) Pressure testing each casing to the MASP plus 500 psi for the next hole section; or (3) Some combination of (1) and (2).
(m) Plan to utilize any other well-control equipment (*e.g.*, but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart;	Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BAVO on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.
(n) You have pipe/variable bore rams that have no current utility or well-control purposes;	Indicate in your APD or APM which pipe/variable bore rams meet these criteria and clearly label them on all BOP control panels. You do not need to function test or pressure test pipe/variable bore rams having no current utility, and that will not be used for well-control purposes, until such time as they are intended to be used during operations.
(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (*e.g.*, pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines);	Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BAVO that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
(p) Need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations.	Ensure that the well is stable prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the removal of the bottom hole assembly from across the BOP in the event of a well-control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

§ 250.739 What are the BOP maintenance and inspection requirements?

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

(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. A BAVO is required to be present during each inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This complete breakdown and inspection must be performed every 5 years from the following applicable dates, whichever is later:

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

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

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

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

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

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

Records and Reporting

§ 250.740 What records must I keep?

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

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

(b) Descriptions of formations penetrated;

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

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

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

(f) Any significant malfunction or problem; and

(g) All other information required by the District Manager as appropriate to ensure compliance with the requirements of this section and to enable BSEE to determine that the well operations are consistent with conservation of natural resources and protection of safety and the environment on the OCS.

§ 250.741 How long must I keep records?

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

You must keep records relating to . . .	**Until . . .**
(a) Drilling;	90 days after you complete operations.
(b) Casing and liner pressure tests, diverter tests, BOP tests, and real-time monitoring data;	2 years after the completion of operations.
(c) Completion of a well or of any workover activity that materially alters the completion configuration or affects a hydrocarbon-bearing zone.	You permanently plug and abandon the well or until you assign the lease and forward the records to the assignee.

§ 250.742 What well records am I required to submit?

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

§ 250.743 What are the well activity reporting requirements?

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

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

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

§ 250.744 What are the end of operation reporting requirements?

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

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

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

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

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

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

(a) Well records as specified in § 250.740;

(b) Paleontological interpretations or reports identifying microscopic fossils by depth and/or washed samples of drill cuttings that you normally maintain for paleontological determinations. The Regional Supervisor may issue a Notice to Lessees that sets forth the manner, timeframe, and format for submitting this information;

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

(d) Other reports and records of operations.

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

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

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

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

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

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

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

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

43. Revise § 250.1612 to read as follows:

Subpart P—Sulphur Operations

§ 250.1612 Well-control drills.

Well-control drills must be conducted for each drilling crew in accordance with the requirements set forth in § 250.711 of this part or as approved by the District Manager.

44. Amend § 250.1703 by:

a. Revising paragraphs (b) and (e);

b. Redesignating paragraph (f) as paragraph (g); and

c. Adding new paragraph (f) to read as follows:

Subpart Q—Decommissioning Activities

§ 250.1703 What are the general requirements for decommissioning?

* * * * *

(b) Permanently plug all wells. Permanently installed packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198);

* * * * *

(e) Clear the seafloor of all obstructions created by your lease and pipeline right-of-way operations;

(f) Follow all applicable requirements of Subpart G; and

* * * * *

45. Amend § 250.1704 by revising paragraph (g) and adding paragraph (h) to read as follows:

§ 250.1704 When must I submit decommissioning applications and reports?

* * * * *

Decommissioning applications and reports	When to submit	Instructions
* * * * * * *		
(g) Form BSEE–0124, Application for Permit to Modify (APM). The submission of your APM must be accompanied by payment of the service fee listed in § 250.125;	(1) Before you temporarily abandon or permanently plug a well or zone,	(i) Include information required under §§ 250.1712 and 250.1721. (ii) When using a BOP for abandonment operations, include information required under § 250.731.
	(2) Before you install a subsea protective device,	Refer to § 250.1722(a).
	(3) Before you remove any casing stub or mud line suspension equipment and any subsea protective device,	Refer to § 250.1723.
(h) Form BSEE-0125, End of Operations Report (EOR);	(1) Within 30 days after you complete a protective device trawl test,	Include information required under § 250.1722(d).
	(2) Within 30 days after you complete site clearance verification activities,	Include information required under § 250.1743(a).

§ 250.1705 [Reserve]

46. Remove and reserve § 250.1705.

47. Amend § 250.1706 by:

a. Revising the section heading;

b. Removing paragraphs (a) through (e); and

c. Redesignating paragraph (f) through (h) as paragraphs (a) through (c).

The revision reads as follows:

§ 250.1706 Coiled tubing and snubbing operations.

* * * * *

§§ 250.1707 through 250.1709 [Reserve]

48. Remove and reserve §§ 250.1707 through 250.1709.

49. In § 250.1715, revise paragraph (a)(3)(iii)(B) to read as follows:

§ 250.1715 How must I permanently plug a well?

* * * * *

(a) * * *

(3) * * *

(iii) * * *

(B) A casing bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;

* * * * *

§ 250.1717 [Reserve]

50. Remove and reserve § 250.1717.

§ 250.1721 [Amended]

51. Amend § 250.1721 by removing paragraph (g) and redesignating paragraph (h) as paragraph (g).