

the identity, fluid content, and characteristics of any penetrated formation in accordance with requirements approved or prescribed by the District Supervisor.

(2) Inclinal surveys shall be obtained on all vertical wells at intervals not exceeding 1,000 feet during the normal course of drilling. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 500 feet during the normal course of drilling and at intervals not exceeding 100 feet in all portions of the hole when angle-changes are planned.

(3) On both vertical and directionally drilled wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 500 feet prior to or upon setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be prepared with the interval shown from the bottom of the conductor casing or, in the absence of conductor casing, from the bottom of the drive or structural casing to total depth. In calculating all surveys, a correction from the true north to Universal-Transverse-Mercator-Grid-north or Lambert-Grid-north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey or a composite measurement-while-drilling (MWD) directional survey including a listing of the directionally computed inclinations and azimuths on a well classified as vertical will be acceptable as fulfilling the applicable requirements of this paragraph. In the event a composite MWD survey is run, a multishot survey shall be obtained at each casing point in order to confirm the MWD results.

(4) Wells are classified as vertical if the calculated average of inclination readings weighted by the respective interval lengths between readings from surface to drilled depth does not exceed 3 degrees from the vertical. When the calculated average inclination readings weighted by the length of the respective interval between readings from the surface to drilled depth exceeds 3 degrees, the well is classified as directional.

(5) The Regional Supervisor at the request of a holder of an adjoining lease may, for the protection of correlative rights, furnish a copy of the directional survey for a well drilled within 500 feet of the adjacent lease to that leaseholder.

(f) *Fixed drilling platforms.* Applications for installation of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with the provisions of subpart I, Platforms and Structures, of this part. Mobile drilling units which have their jacking equipment removed or have been otherwise immobilized are classified as fixed drilling platforms.

(g) *Equipment movement.* The movement of drilling rigs and related equipment on and off an offshore platform or from well to well on the same offshore platform, including rigging up and rigging down, shall be conducted in a safe manner. All wells in the same well-bay which are capable of producing hydrocarbons shall be shut in below the surface with a pump-through-type tubing plug and at the surface with a closed master valve prior to moving such rigs and related equipment, unless otherwise approved by the District Supervisor. 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.

(h) *Emergency shutdown system.* When drilling operations are conducted on a platform where there are other hydrocarbon-producing wells or other hydrocarbon flow, an Emergency Shutdown System (ESD) manually controlled station shall be installed near the driller's console.

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§§ 250.402–250.403 [Reserved]

§ 250.404 Well casing and cementing.

(a) *General requirements.* (1) For the purpose of this subpart, the casing strings in order of normal installation are as follows:

(i) Drive or structural,

- (ii) Conductor,
- (iii) Surface,
- (iv) Intermediate, and
- (v) Production casing.

(2) The lessee shall case and cement all wells with a sufficient number of strings of casing and quantity and quality of cement in a manner necessary to prevent release of fluids from any stratum through the wellbore (directly or indirectly) into offshore waters, prevent communication between separate hydrocarbon-bearing strata, protect freshwater aquifers from contamination, support unconsolidated sediments, and otherwise provide a means of control of the formation pressures and fluids. Cement composition, placement techniques, and waiting time shall be designed and conducted so that the cement in place behind the bottom 500 feet of casing or total length of annular cement fill, if less, attains a minimum compressive strength of 500 pounds per square inch (psi). Cement placed across permafrost zones shall be designed to set before freezing and have a low heat of hydration.

(3) The lessee shall install casing designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; and combinations thereof. Safety factors in the casing program design shall be of sufficient magnitude to provide well control during drilling and to assure safe operations for the life of the well. Any portion of an annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid which has a freezing point below the minimum permafrost temperature to prevent internal freezeback and which is treated to minimize corrosion.

(4) In cases where cement has filled the annular space back to the mud line, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment if the District Supervisor determines that subsurface protection against damage to freshwater aquifers and permafrost zones and against damage caused by adverse loads, pressures, and fluid flows is not jeopardized.

(5) If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall re-cement or take other remedial actions as approved by the District Supervisor.

(6) A pressure-integrity test shall be run below the surface casing, the intermediate casing(s), and liner(s) used as intermediate casing(s). The District Supervisor may require a pressure-integrity test to be run at the conductor casing shoe due to local geologic conditions or planned casing setting depths. Pressure-integrity tests shall be made after drilling new hole below the casing shoe and before drilling more than 50 feet of new hole below a respective casing string. These tests shall be conducted either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as specified in the approved APD. A safe margin, as approved by the District Supervisor, shall be maintained between the mud weight in use and the equivalent mud weight at the casing shoe as determined in the pressure-integrity test. Drilling operations shall be suspended when the safe margin is not maintained. Pressure-integrity and pore-pressure test results and related hole-behavior observations, such as gas-cut mud and well kicks made during the course of drilling, shall be used in adjusting the drilling mud program and the approved setting depth of the next casing string. The results of all tests and of hole-behavior observations made during the course of drilling related to formation integrity and pore pressure shall be recorded in the driller's report.

(b) *Drive or structural casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth as may be prescribed or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, a quantity of cement sufficient to fill the

annular space back to the mud line shall be used.

(c) *Conductor and surface casing requirements.* (1) *Conductor and surface casing setting depths.* Conductor and surface casing design and setting depths shall be based upon relevant engineering and geologic factors including the presence or absence of hydrocarbons, potential hazards, and water depths. The approved casing setting depths may be adjusted when the change is approved by the District Supervisor to permit the casing shoe to be set in a competent formation or below formations which should be isolated from the wellbore by casing for safer drilling operations. However, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas or, if the presence of oil or gas is unknown, upon encountering a formation containing oil or gas. Upon encountering unexpected formation pressures, the lessee shall submit a revised casing program to the District Supervisor for approval. The District Supervisor may permit a lessee to drill a well without setting conductor casing provided the information from approved logging and mud-monitoring programs for wells previously drilled in the immediate vicinity combined with other available geologic data are sufficient to demonstrate the absence of shallow hydrocarbons or hazards.

(2) *Conductor casing cementing requirements.* Conductor casing shall be cemented with a quantity of cement that fills the calculated annular space back to the mud line except as applicable to the bottom of an excavation (glory hole) or to the surface of an artificial island. Cement fill in annular spaces shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible, additional quantities of cement shall be used to assure fill to the mud line.

(3) *Surface casing cementing requirements.* (i) Surface casing shall be cemented with a quantity of cement that fills the calculated annular space to at least 200 feet inside the conductor casing. When geologic conditions such as near-surface fractures and faulting exist, surface casing shall be cemented

with a quantity of cement that fills the calculated annular space to the mud line, or as approved or prescribed by the District Supervisor.

(ii) For floating drilling operations, a lesser volume of cement may be used to prevent sealing the annular space between the conductor casing and surface casing if the District Supervisor determines that the uncemented space is necessary to provide protection from burst and collapse pressures which may be applied inadvertently to the annulus between casings during blowout preventer (BOP) testing operations. Any annular space open to the drilled hole shall be sealed in accordance with the requirements for abandonment in subpart G, Abandonment of Wells, of this part.

(d) *Intermediate casing requirements.* (1) Intermediate casing string(s) shall be set for protection when geologic characteristics or wellbore conditions, as anticipated or as encountered, so indicate.

(2) Quantities of cement that cover and isolate all hydrocarbon-bearing zones in the well and isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 500 feet above the zones to be isolated or 500 feet above the casing shoe in wells where zonal coverage is not required.

(3) If a liner is to be used as an intermediate string below a surface casing string, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for intermediate casing. When a liner is to be used as production casing below a surface casing string, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

(e) *Production casing requirements.* (1) Production casing shall be cemented to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a volume sufficient to fill the annular space at least 500 feet

above the uppermost hydrocarbon-bearing zone shall be used.

(2) When a liner is to be used as production casing below intermediate casing, it shall be lapped a minimum of 100 feet into the previous casing string and cemented as required for the production casing.

§ 250.405 Pressure testing of casing.

(a) Prior to drilling the plug after cementing and in the cases of plugs in production casing strings and liners not planned to be subsequently drilled out, all casings, except the drive or structural casing, shall be pressure tested to 70 percent of the minimum internal-yield pressure of the casing or as otherwise approved or required by the District Supervisor. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run and the casing pressure tested again. Additional remedial actions shall be taken until a satisfactory pressure test is obtained. The results of all casing pressure tests shall be recorded in the driller's report.

(b) Each production liner lap shall be tested to a minimum of 500 psi above formation fracture pressure at the shoe of the casing into which the liner is lapped, or as otherwise approved or required by the District Supervisor. The drilling liner-lap test pressure shall be equal to or exceed the pressure that will be encountered at the liner lap when conducting the planned pressure-integrity test below the liner shoe. The test results shall be recorded on the driller's report. If the test indicates an improper seal, remedial action shall be taken which provides a proper seal as demonstrated by a satisfactory pressure test.

(c) In the event of prolonged drill-pipe rotation within a casing string run to the surface or extended operations such as milling, fishing, jarring, washing over, and other operations which could damage the casing, the casing shall be pressure tested or evaluated by a logging technique such as a caliper log every 30 days. The evaluation results shall be submitted to the District Supervisor with a determination of effects of operations on the in-

tegrity of the casing for continued service during drilling operations and over the producing life of the well. If the integrity of the casing in the well has deteriorated to an unsafe level, remedial operations shall be conducted or additional casing set in accordance with a plan approved by the District Supervisor prior to continuing drilling operations.

(d) After cementing any string of casing other than the structural casing string, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string and 12 hours under pressure for all other casing strings. Cement is considered under pressure if one or more float valves are shown to be holding the cement in place or when other means of holding pressure are used.

§ 250.406 Blowout preventer systems and system components.

(a) *General.* The BOP systems and system components shall be designed, installed, used, maintained, and tested to assure well control.

(b) *BOP stacks.* The BOP stacks shall consist of an annular preventer and the number of ram-type preventers as specified under paragraphs (e)(1), (f), and (g) of this section. The pipe rams shall be of a proper size(s) to fit the drill pipe in use.

(c) *Working pressure.* The working-pressure rating of any BOP component shall exceed the anticipated surface pressure to which it may be subjected. The District Supervisor may approve a lower working pressure rating for the annular preventer if the lessee demonstrates that the anticipated or actual well conditions will not place demands above its rated working pressure. (Refer to related requirements in § 250.414(f)(3)(ii) of this part.)

(d) *BOP equipment.* All BOP systems shall be equipped and provided with the following:

(1) An accumulator system which shall provide sufficient capacity to supply 1.5 times the volume of fluid necessary to close and hold closed all BOP equipment units with a minimum pressure of 200 psi above the precharge pressure without assistance from a