

§ 250.1624 Blowout prevention equipment.

(a) The BOP system and system components and related well-control equipment shall be designed, used, maintained, and tested in a manner necessary to assure well control in foreseeable conditions and circumstances, including subfreezing conditions. The working pressure of the BOP system and system components shall equal or exceed the expected surface pressure to which they may be subjected.

(b) The minimum BOP stack for well-completion operations or for well-workover operations with the tree removed shall consist of the following:

(1) Three remote-controlled, hydraulically operated preventers including at least one equipped with pipe rams, one with blind rams, and one annular type.

(2) When a tapered string is used, the minimum BOP stack shall consist of either of the following:

(i) An annular preventer, one set of variable bore rams capable of sealing around both sizes in the string, and one set of blind rams; or

(ii) An annular preventer, one set of pipe rams capable of sealing around the larger size string, a preventer equipped with blind-shear rams, and a crossover sub to the larger size pipe that shall be readily available on the rig floor.

(c) The BOP systems for well-completion operations, or for well-workover operations with the tree removed, shall be equipped with the following:

(1) An accumulator system that provides sufficient capacity to supply 1.5 times the volume 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 charging system. After February 14, 1992, accumulator regulators supplied by rig air which do not have a secondary source of pneumatic supply shall be equipped with manual overrides or alternately other devices provided to ensure capability of hydraulic operations if rig air is lost;

(2) An automatic backup to the accumulator system supplied by a power source independent from the power source to the primary accumulator system and possessing sufficient capacity

to close all BOP's and hold them closed;

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

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

(5) A choke line and a kill line each equipped with two full-opening valves and a choke manifold. One of the choke-line valves and one of the kill-line valves shall be remotely controlled except that a check valve may be installed on the kill line in lieu of the remotely-controlled valve provided that two readily accessible manual valves are in place, and the check valve is placed between the manual valve and the pump.

(d) The minimum BOP-stack components for well-workover operations with the tree in place and performed through the wellhead inside of the sulphur line using small diameter jointed pipe (usually $\frac{3}{4}$ inch to $1\frac{1}{4}$ inch) as a work string; *i.e.*, small-tubing operations, shall consist of the following:

(1) For air line changes, the well shall be killed prior to beginning operations. The procedures for killing the well shall be included in the description of well-workover procedures in accordance with § 250.1622 of this part. Under these circumstances, no BOP equipment is required.

(2) For other work inside of the sulphur line, a tubing stripper or annular preventer shall be installed prior to beginning work.

(e) An essentially full-opening, work-string safety valve shall be maintained on the rig floor at all times during well-completion operations. A wrench to fit the work-string safety valve shall be readily available. Proper connections shall be readily available for inserting a safety valve in the work string.

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§ 250.1625 Blowout preventer system testing, records, and drills.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) Ram-type BOP's and the choke manifold shall be pressure tested with water to a rated working pressure or as

otherwise approved by the District Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

- (1) When installed;
- (2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;
- (3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is a stuck drill pipe or there are pressure control operations, and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The time, date, and reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams;
- (4) Blind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than necessary to indicate proper operation of the rams is not required;
- (5) Variable bore-pipe rams shall be pressure tested against all sizes of pipe in use, excluding drill collars and bottomhole tools; and
- (6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly, the pressure tests may be limited to the affected component.

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

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Manager. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

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

- (1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the operations log may reference a BOP test plan that contains the required information and is retained on file at the facility.
- (2) The control station used during the test shall be identified in the operations log.
- (3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the operations log.
- (4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections shall be available for MMS review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Manager.