5. INSPECTION AND TESTING PROCEDURES

5-1 GENERAL

a. If **BOPE inspection and/or testing is required on the division's Permit to Conduct Well Operations (Form OG 111)**, inspections must be made by a division representative accompanied by the operator's and/or contractor's representative. The division inspector must verify that all of the requirements for casing, BOPE, hole-fluid monitoring equipment, and pressure rating are satisfied.

b. In most cases, **BOPE tests are conducted prior to drilling below the casing shoe or kick-off point (KOP)**. In situations where the casing is open to the formation, a sealing device (either cement or mechanical) must be placed as close as practical to the shoe or KOP (whichever is higher) so that the casing's mechanical integrity can be determined. The anchor casing string, to which the BOP stack is attached, is an integral part of the BOPE and must be tested, either separately or in conjunction with the BOP stack.

c. When **pressure testing blowout prevention equipment**, all components of the BOP stack, kill- and choke-line valves, working-string safety valve, internal preventer, kelly cock(s), and standpipe valve must be tested in the direction of blowout flow. Clean water should be used as the test fluid, especially in critical areas.

d. When **selecting a suitable test pressure** for the BOPE and anchor casing string, two factors need to be considered: the Maximum Predicted Casing Pressure (MPCP) for the well, and the Minimum Internal Yield Pressure (MIYP) of the anchor casing string. When testing casing in conjunction with the BOPE, the maximum pressure applied to the shoe of the anchor string (or KOP) must not exceed 125 percent of the MPCP or 80 percent of the MIYP, whichever is lower.

To calculate the appropriate maximum test pressure, determine the following values:

1) The hydrostatic pressure (hp) of the fluid in the well.
2) The surface pressure equivalent of 125 percent of the MPCP (see paragraph 2-5a to calculate MPCP).
3) The surface pressure equivalent of 80 percent of the MIYP of the anchor string (see Appendix D for MIYP values).

Example: <u>Well 1X</u>

Surface casing: 13 3/8" cem 1000'

Intermediate casing: 9 5/8", 40#, N-80 cem 4220' (4000' TVD)

Proposed TD: 9450' MD (8800' TVD)

TD formation pressure: 4200 psi

Mud weight (MW): 9.6 ppg

1) hp @ shoe = (MW ppg X 0.052) X TVD
= (9.6 ppg X 0.052) X 5000'
= 2496 psi

2) MPCP surface test pressure
= (MPCP X 1.25) – hp
= (3486 X 1.25) – 2496
= **2360 psi**

3) 80% MIYP surface test pressure
= (MIYP X 0.80) – hp
= (5750 X 0.80) – 2496
= **2104 psi**

In the example above, the surface test pressure must not exceed 2,100 psi to prevent rupturing the casing.

In non-sensitive onshore areas, the test pressure may be limited to 1,000 psi. If the pressure determined in the equations above is below 1,000 psi, then a test plug may be considered for testing the BOPE. In some cases, the operator may require a test to the full working pressure of the BOPE using a test plug. This would be followed by a separate casing test at the pressure determined from the equations above.

e. When pressure testing the BOPE and/or casing, pressure must be applied until a stabilized reading can be confirmed (a minimum of three minutes). A pressure drop of more than 10 percent is unacceptable.

f. **Results of all required tests** will be recorded on Division of Oil, Gas, and Geothermal Resources Form OGD9.

5-2 TESTING THE ACTUATING SYSTEM

a. **Accumulator Unit**

1. Determine that each valve on the unit is in good condition and operates properly with no leaks, that each is provided with a satisfactory handle, and that each valve can be operated without mechanical assistance.

2. Determine that the accumulator is fully charged to its rated working pressure (+/- 10 percent).

3. Determine that the level of the hydraulic fluid in the reservoir is within one inch of the level prescribed for the accumulator unit in use. For Hydril units, the prescribed level is indicated by a petcock on the reservoir near the accumulator pumps. For most other units, the fluid level of the fully charged accumulator(s) should be such that draining the pressurized fluid from the accumulator bank can be accomplished without causing the reservoir to overflow. This level will vary, depending on the dimensions of the reservoir and the number and operating characteristics of the accumulator(s).

4. Note the total accumulator volume. If it appears inadequate according to the graphs at Appendix F, the system can be tested using the following procedure (assuming all lines and the preventer operating chambers are filled with fluid):

   a) Isolate the accumulator pump motor from its power supply.

   b) Hang the smallest OD pipe (for which pipe rams have been installed) through the preventers and perform the following test sequence within a two-minute period:

      1) Close the ram preventer that contains the rams corresponding to the pipe size in use.

      2) Close the annular preventer.

      3) Open the pipe rams.

      4) Perform all immediate kick-control responses involving any installed auxiliary equipment that depends on the accumulator unit for actuating energy. This would include, but not be limited to, opening any hydraulically-operated control valves in the choke system.

      Extend the two-minute period for preventers with very large operating volumes when performing this sequence of actions. The time extension will cover the time that fluid is moving continuously in the system.

   c) After following the test sequence outlined in paragraph 5-2a4b), ensure that the pressure remaining in the accumulator(s) conforms to the following requirements:

      1) For accumulator units having a nominal precharge pressure of 750 psi, the remaining pressure must be **1,000 psi or higher** because 1,000 psi is the average pressure required to keep an annular preventer closed on open hole. (Note that this required pressure is 50 psi higher than the API recommendation of 200 psi above the precharge pressure.)

      2) For accumulator units having a nominal precharge pressure of 1,000 psi, the remaining pressure must be **1,200 psi or higher**.

   d) If the remaining pressure is higher than the value required for the type of system tested, reconnect the charging pump and continue with the testing. If the remaining pressure is too low, the actuating system is inadequate and testing must be suspended until the inadequacy is eliminated.

5. Suspect a low precharge pressure in a seemingly adequate accumulator unit if there is an abnormally rapid pressure drop as the preventers are actuated, or if there is an abnormally slow pressure buildup in the system when the charging pumps are restarted after performing the test outlined in paragraph 5-2a4.

The precharge pressure may be field tested using the following procedures:

a) Isolate the accumulator pump motor from its power supply.

b) If the accumulator unit in use is a 1,500 psi working-pressure unit with a separate control manifold, isolate the unit by closing the master valve on the pressure line between the accumulator unit and the control manifold. **Do not close the master valve on the accumulator line in the 2,000 or 3,000 psi working-pressure units, as this will isolate the control manifold from the accumulator bank and the test cannot be performed.**

c) Open the manifold bypass valve slowly, venting the fluid from the accumulator(s) into the reservoir. **WARNING: THE FLUID WILL OVERFLOW IF ITS LEVEL IS SIGNIFICANTLY HIGH WHEN COMPARED WITH THE RECOMMENDATIONS OF PARAGRAPH 5-2a3. BE CERTAIN THAT THE RESERVOIR IS VENTED TO PREVENT THE POSSIBILITY OF AIR BEING TRAPPED ABOVE THE RISING FLUID.** (The reservoir will be damaged severely if the vent is missing or plugged.) If gas follows the fluid into the reservoir, a ruptured separator is indicated. This condition must be corrected before testing can be continued.

d) Wait at least 30 minutes for the temperature of the accumulator gas to return to normal, because rapid expansion of the precharge gas in the accumulator(s) during the bypass process will cool the gas significantly.

e) With the bypass valve open, reconnect the charging pump motor to its power supply and observe the bypass-line port through the inspection hole in the top (or ends) of the fluid reservoir to ensure the accumulator pumps are moving fluid. Then, close the bypass valve and watch the accumulator pressure gauge. After the first few pump strokes, the pressure gauge needle should jump to the precharge pressure specified by the manufacturer, and then rise slowly to the pressure determined by the pressure switch setting. An initial pressure indication lower than the specified precharge is evidence that one or more of the accumulators in the system is precharged inadequately. This condition must be corrected before the BOPE can be approved. The graphs in Appendix F illustrate the importance of correct precharge to the performance of the accumulator.

6. Determine that all accumulator charging pumps are functioning adequately by applying the following test:

   a) Record the time required to restore full working pressure after each preventer is closed.

   b) Obtain the volume required to close each preventer from Appendix A or B, as applicable.

   c) Divide the closing volume of each preventer by the recovery time (in minutes) for that preventer and compare the result with the rated output of the pumps. The calculated output should not be less than 80 percent of the rated output.

7. Determine that the power supply to the accumulator pump motor will not be interrupted during normal well operations. The plug at the power panel must not share a common outlet with any equipment that would necessitate unplugging the accumulator power at any time.

b. **Emergency Backup System**

1. ***High-pressure Nitrogen Backup System***

   a) Determine that this system is charged adequately by performing the following test:

      1) Ensure that a gauge is installed that will register pressure in the backup system when it is isolated from the accumulator unit.

      2) Check the line valve between the backup system and the accumulator unit to ensure that the valve is closed tightly.

      3) Open and close the shutoff valve on the top of each nitrogen bottle in turn, and record the pressure indicated by the gauge. (An undercharged bottle will accept the small quantity of nitrogen left in the line from the previous bottle without a significant effect on its pressure reading.)

      4) Using the graph shown in Figure 11, find the pressure recorded for each cylinder and determine how much available working-fluid equivalent remains

in the backup system. This total working-fluid equivalent should be sufficient to close and open a ram preventer *and* close the annular preventer on pipe.

b) Determine the integrity of the system by watching the pressure gauge after all of the bottle shutoff valves have been closed. There should be no decrease in pressure.

2. ***Accumulator Backup System***

a) Determine that the active and backup bank(s) of accumulator bottles are each equipped with valves capable of isolating them from the rest of the system, and that the valve(s) for the backup system are kept closed during normal operations.

b) Determine, by calculation, that the capacity of the backup bank(s) is sufficient to perform the test required by paragraph 5-2a4.

c) Determine that the isolation valves can be operated by one person without mechanical assistance, and that there is a full charge in the backup bank(s) by performing the following test:

1) Close the isolation valve to the working bank(s).

2) Open the isolation valve to the backup bank(s) and notice the pressure indicated by the ACCUMULATOR pressure gauge on the control manifold. The pressure should be equal to the full working pressure of the accumulator unit.

3) Close the valve to the backup bank(s) and reopen the valve to the working bank(s).

c. **Control Manifold**

1. Determine that the distance is at least 50 feet from the well bore to the control manifold, which may be mounted on the accumulator unit.

2. Determine that the four-way control valves are identified as to function and the arrows showing the direction of movement of the valve handles are such that the probability of confusion during an emergency is minimized. Identification must be physically removed or otherwise obliterated from any four-way valve not connected to equipment at the wellhead.

If the four-way valve for the CSO rams has been equipped with any type of guard to prevent accidental movement of the operating handle, ensure that the guard does not interfere with actuation of the preventer from the remote station.

3. Determine that access to the control manifold is unobstructed and that the four-way valve handles can be operated by a person standing in front of the manifold at a place where the valve-identification signs are clearly visible.

4. Determine that the four-way control valves and any pressure-regulating valves can be operated by one person, without mechanical assistance of any kind.

5. As each of the four-way valves is operated, observe the flow from the return line into the fluid reservoir to ensure flow of displaced fluid stops when the preventer has finished closing or opening. A continuation of flow indicates the four-way valve is not functioning properly or that the seal rings in the associated preventer may be defective. Either of these conditions will continue to reduce the accumulator pressure and must be corrected before testing can be continued.

6. Determine, as nearly as is practicable, that the gauges indicating line pressure on each side of the annular-preventer regulating valve are functioning properly.

d. **Remote Station**

1. Determine that a remote station, when required, is located as close as is practicable to the position normally occupied by the driller or head well puller while pipe is being pulled from the hole. If the configuration of the drilling floor permits, this distance should not be more than 10 feet.

2. Use a remote station to close each of the preventers during the test.

5-3 TESTING THE BOPE STACK, CHOKE AND KILL SYSTEM, AND AUXILIARY EQUIPMENT

a. **General**. The division inspector must study the BOPE array on each well in the field so that the function of each item of BOPE is understood clearly and so conclusive testing of the entire array can be carried out.

Also, an operator's or contractor's BOPE test plan may not agree with some of the procedures suggested here; therefore, the division inspector should not contravene the operator's test procedures unless there is a valid reason for doing so. For example, the system of valves can be tested by progressively closing the upstream valves and opening the downstream valves while keeping pressure on the system. This procedure permits the fastest testing of each of the valves, but some people feel that such a procedure will cause the premature failure of the valves by cutting out the valve gates and/or seats. Field experience does not support this concern; however, some rig supervisors prefer bleeding the pressure between each test. Another possible drawback to the method of testing valves through progressive upstream valve closure is that certain types of gate valves absorb some of the line pressure into the pressure-balancing system in the valve body, causing a reduction in the test pressure. Although this is not necessarily an indication of leakage in the gate area of the valve, rebuilding the test pressure with the rig pumps is very difficult in such situations because of the small volumes involved. The testing sequence outlined in this section assumes a Class IV 5M BOPE array tested against a casinghead BOPE test plug as shown in Figures 27-1 through 27-6b. The actual arrangement of equipment, valves, and gauges on a well in the field will probably vary from these illustrations; however, the general test sequences given here are adaptable to other classes and arrangements of equipment, tested with or without the test plug.

CAUTION: When testing without a test plug, the division engineer must ensure that adequate pipe is run so the string will not be jacked out of the hole by the test pressures.

This testing sequence also assumes that test pressures are applied with rig pumps. If a separate test pump is to be used, certain procedures outlined here will not be applicable. Again, the division inspector must modify the testing sequence to provide for conclusive testing. (If a separate test pump is used to test the equipment, it is important that the point of attachment of the testing pressure line is pressure tested after the line is removed. This can be accomplished during the pressure test of the casing required in paragraph 5-1c.)

The division inspector should not require or recommend pressure testing needle-and-seat type chokes in the closed position. Although the operator's instructions may include requirements for such testing, most chokes of this type are not designed to function well as full-closing valves, and they are likely to get cut out if so used. It is preferable that the choke be available for the job it is designed to do, rather than risk compromising its integrity in testing. The pressure integrity of the choke bodies will be tested during the test outlined in paragraph 5-3b, which follows. Each adjustable choke should be cycled either manually or hydraulically to ensure that it is fully operable.

Drilling and workover contractors should maintain BOPE maintenance records at the rig site. These records should indicate the manufacturer, model, nominal size, pressure rating, and overhaul history of each of the preventers. The history should show the overhaul dates, a description of any work done, the manufacturer(s) of replacement and repair parts, and the manufacturer(s) of all seals, rams, and packing elements contained in the preventer(s). If the equipment has been rented, these records should be obtained from the rental company.

In the accompanying figures, Figure 27-1 is simply a diagram of the BOPE system as it should appear during normal drilling operations (the drill-ahead condition). All of the preventers are in the open position, the valves closest to the well bore (the master valves) on the kill line and the choke line are closed, the kill line high-pressure access valve and the casinghead outlet valve are closed, and all the other valves in the system are open. This configuration presents the least opportunity for choke-line plugging during circulation. This configuration may differ from one seen in the field if an operator's blowout-prevention plan calls for a soft shut in. This type of shut in would be facilitated by drilling with the wellhead valves on the choke line open and the choke manifold valves open through one choke. All of the other valves in the choke manifold would be maintained in the closed position. In such cases, the division inspector should determine that the operator's blowout prevention planning provides for flushing the choke line periodically to keep it free of obstructions.

CAUTION: If a preventer has been closed for any reason, the hole space below that preventer must be vented through the choke line or a relief valve to bleed off any trapped pressure before the preventer is reopened. In any case, all personnel must stand away from the well bore when a preventer is opened after testing.

In Figures 27-2 through 27-6, major changes are indicated in the system configurations to accommodate a particular test or series of tests. The alpha characters (a to k) that follow the figure numbers indicate changes in valve positions to test a particular item of equipment while maintaining the general configuration of the system.

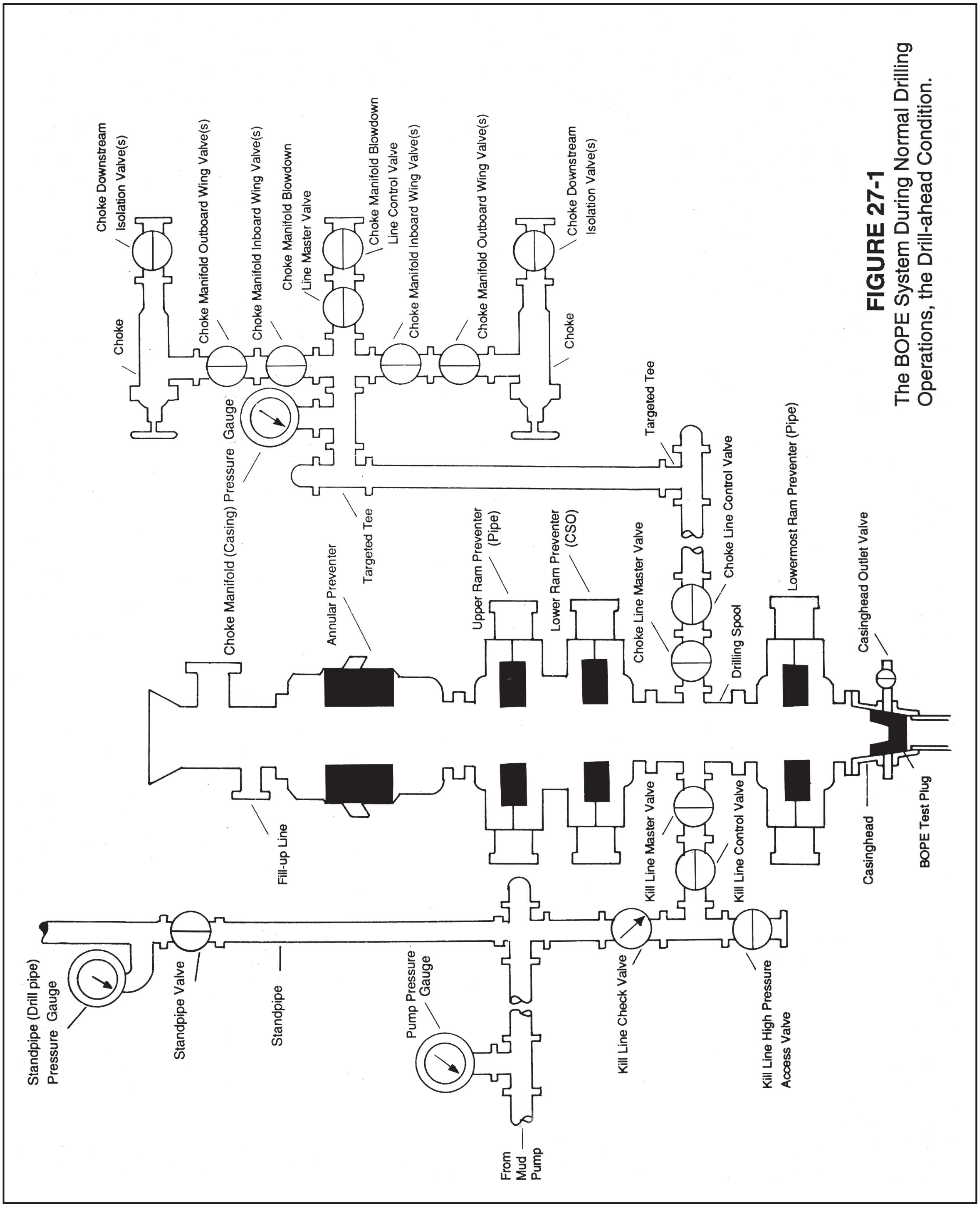


FIGURE 27-1
The BOPE System During Normal Drilling Operations, the Drill-ahead Condition.

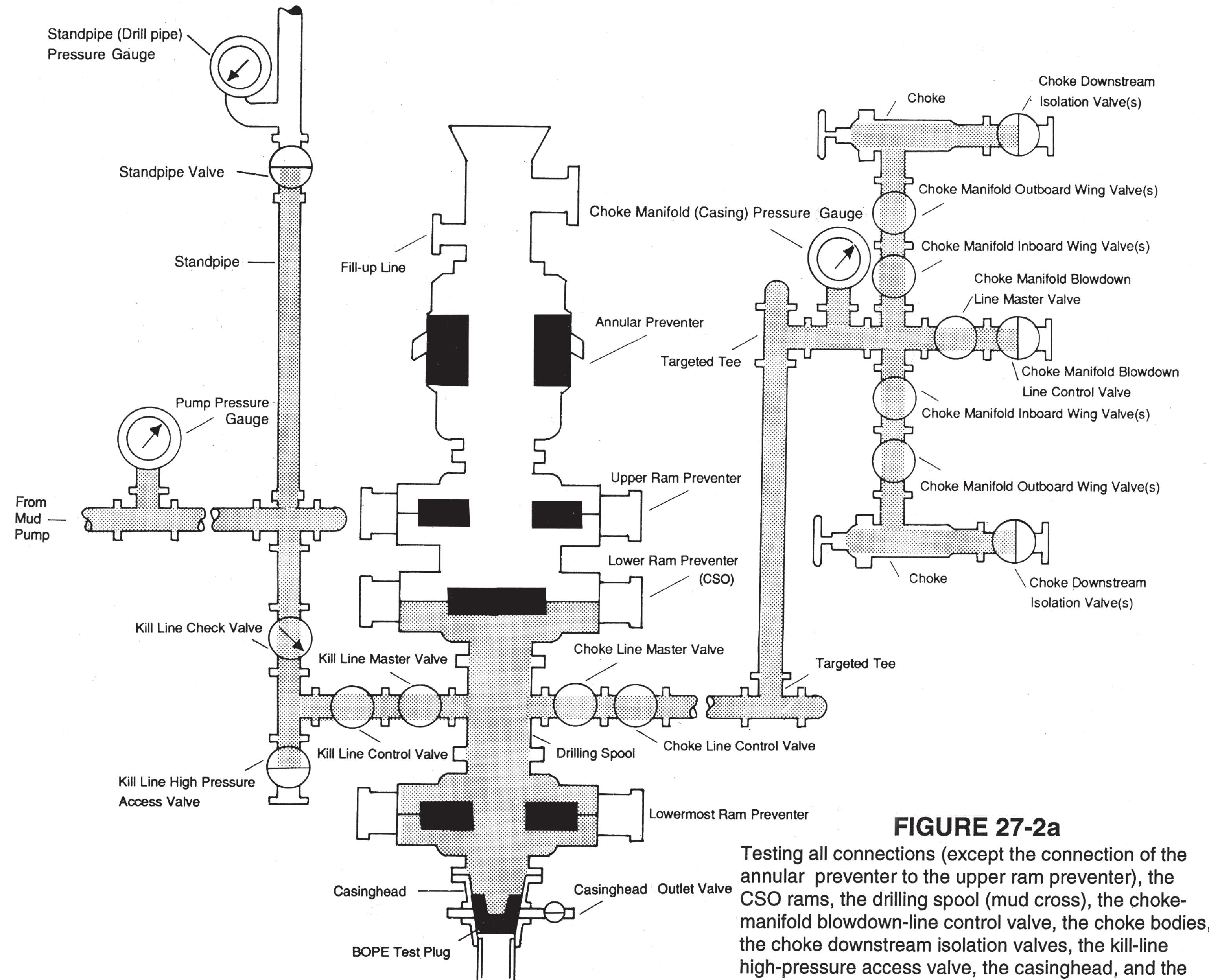


FIGURE 27-2a

Testing all connections (except the connection of the annular preventer to the upper ram preventer), the CSO rams, the drilling spool (mud cross), the choke-manifold blowdown-line control valve, the choke bodies, the choke downstream isolation valves, the kill-line high-pressure access valve, the casinghead, and the BOPE test plug.

If the system is equipped with a remote-controlled hydraulic choke, the manifold (casing) pressure gauge and the standpipe (drill pipe) pressure gauge (in Figures 27-3, 27-4, and 27-5) also will be located at the choke control panel, which usually is sited on the rig floor. During testing, the division inspector should check the panel gauges to see that the panel is connected correctly and the indicated pressures agree with those on the respective gauges in the other parts of the system.

Two items of auxiliary equipment, the drill pipe full-opening safety valve and the internal preventer, do not appear in the figures until they are tested with the configuration shown in Figure 27-6a and 27-6b.

b. **Testing all connections** (except the connection of the annular preventer to the upper ram preventer), **the CSO rams, the drilling spool (mud cross), the choke-manifold blowdown-line control valve, the choke bodies, the choke downstream isolation valves, the kill-line high-pressure access valve, the casinghead, and the BOPE test plug (Figure 27-2a).**

1. **If the testing is to be performed with a separate test pump**, open the casinghead outlet valve and drain the drilling fluid from the BOP stack.

   If the testing is to be performed with the rig mud pumps, disregard this step.

2. Seat the BOPE test plug in the casinghead. Back the drill pipe out of the test plug, and remove the drill pipe from the hole.

3. **If fresh water is to be used as the test fluid** and the mud was not drained, use water to displace the mud in the wellhead stack. In extremely cold weather, it may be necessary to buffer the water to keep it from freezing during the test.

4. Open the casinghead outlet valve if it was not opened already in Step 1.

5. Close the CSO rams, using the remote control panel at the driller's station.

6. Close the standpipe valve.

7. Open the kill-line master valve and the choke-line master valve.

8. Close the choke downstream-isolation valves and the choke-manifold blowdown-line control valve.

9. Apply test pressure through the kill line, noting any discrepancies between the readings on the pump pressure gauge and the choke-manifold pressure gauge. These pressure readings should be within 10 percent of each other. In addition, if a remotely controlled choke has been installed, the casing pressure gauge on the choke-control panel must be checked to see that the panel has been connected correctly and the gauge is accurate. If the system does **not** hold pressure, perform the following checks.

   a) Inspect for leakage at all pressure connections, from the mud pump through the wellhead equipment and the choke manifold. The exterior of the BOPE should have been cleaned for the test, but, in some cases, it may be necessary to hose off the entire assembly and then dry it so that minor leaks become visible.

   b) Observe the outlet at the casinghead outlet valve to see if fluid is bypassing the seal rings on the BOPE test plug. If there is no leakage at that point, close the casinghead outlet valve.

   c) If the cause of the leakage has not been determined during this testing, suspect the ram rubbers, the ram-block seal rings, or the ram-shaft packing in the CSO ram preventer. If the operator filled the hole completely before starting the test, ram-block or seal-ring failure will result in flow at the flow line. A ramshaft packing leak may result in return flow into the accumulator unit reservoir. This set of problems can be solved only at the technical-service level and requires disassembly of the preventer.

c. **Testing the Kill-line Check Valve** (**Figure 27-2b**)

1. Bleed off the pressure rapidly at the mud pump. The sudden pressure drop in the kill line should cause the check valve to close. This closing is sometimes accompanied by a rather loud sound.

2. After the check valve has closed, the pressure indicated at the pump pressure gauge should drop to zero, while the reading at the choke manifold (casing) pressure gauge remains at or near the original test value.

3. Do not attempt to test the choke manifold wing valves in conjunction with the check valve, because it is difficult to identify the point of leakage if the pressure at the choke manifold (casing) pressure gauge begins to drop.

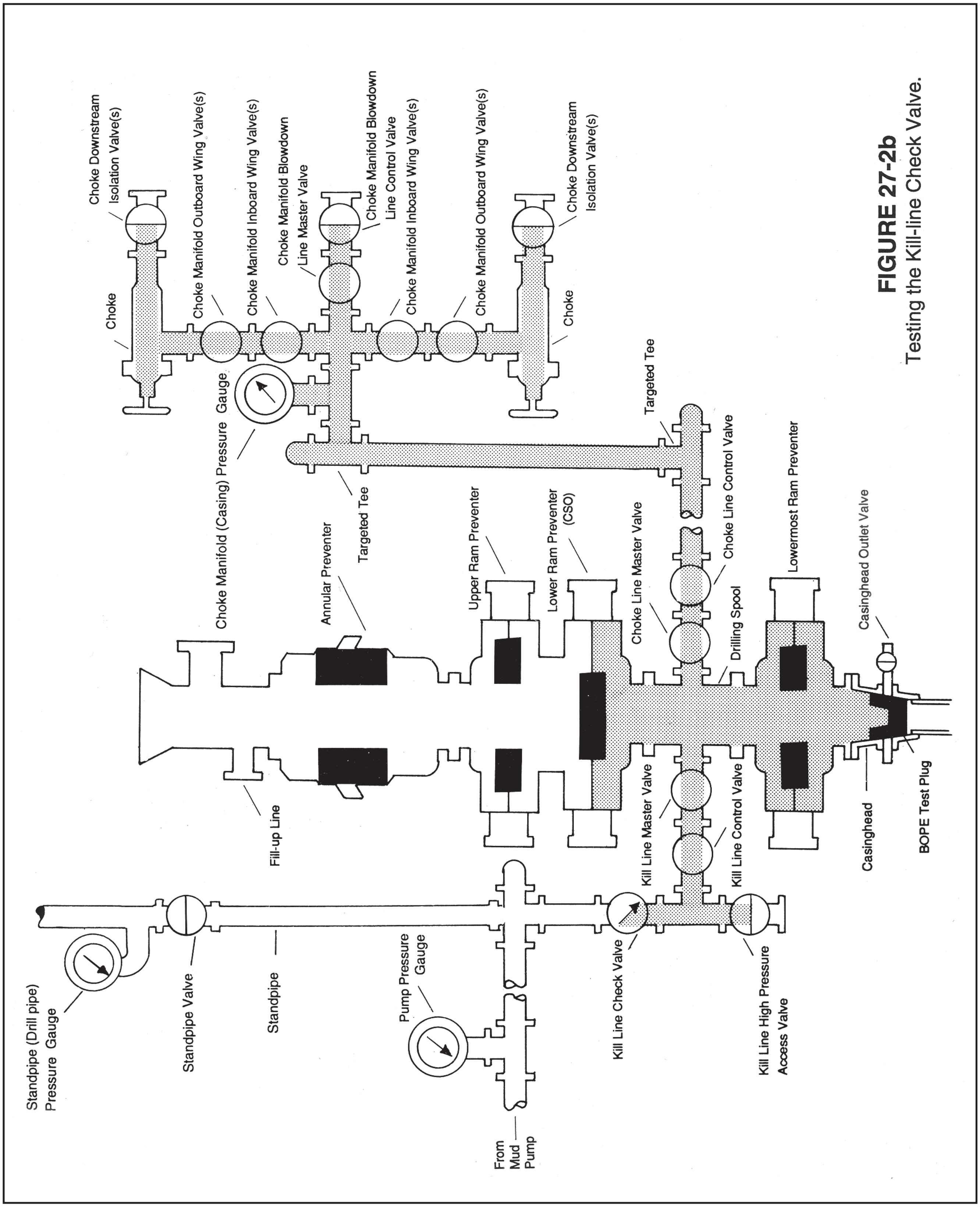


FIGURE 27-2b
Testing the Kill-line Check Valve.

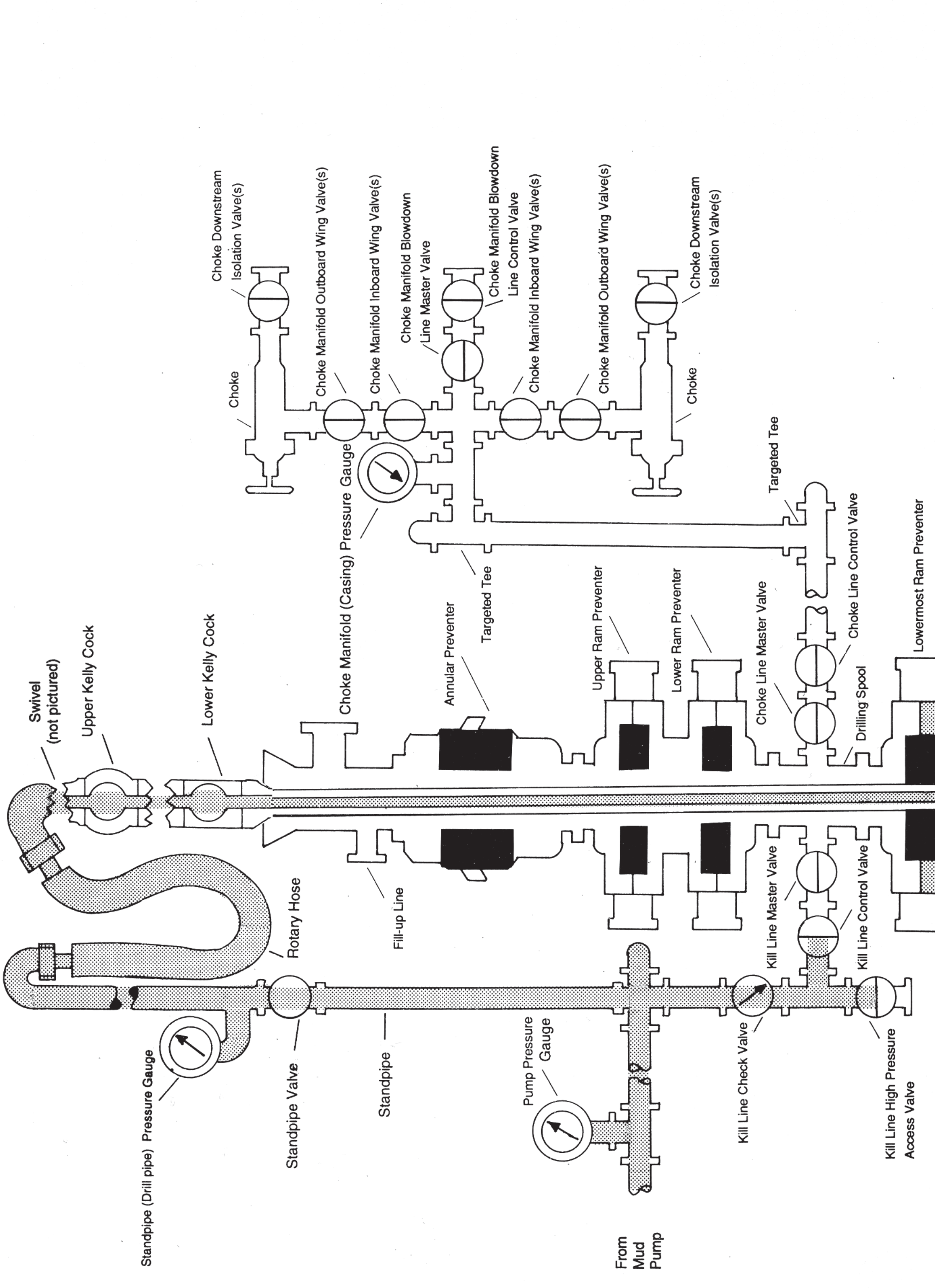


FIGURE 27-3
Testing the Lowermost Ram Preventer, the Swivel, the Rotary Hose and Connections, and the Standpipe Connections.

4. Bleed the test pressure at the choke manifold blow-down line control valve and open the CSO rams using the four-way valve at the accumulator unit.

d. **Testing the Lowermost Ram Preventer, the Swivel, the Rotary Hose and Connections, and the Standpipe Connections (Figure 27-3)**

1. Insert a joint of drill pipe into the test plug, making some provision for weeping pressure from the drill pipe to the wellhead stack. The weeping required for this step may be accomplished with a weep-hole sub installed between the drill-pipe joint and the test plug, or with a test plug that has a weep hole built into it.

2. Open the standpipe valve and close the kill-line control valve. The position of the rest of the choke- and kill-line valves during this step is unimportant because none of them will be tested.

3. Attach the kelly to the drill pipe in the BOP stack so the standpipe (drill pipe) pressure gauge will be available for testing.

4. Close the lowermost rams using the remote control panel at the driller's station.

5. Apply test pressure through the drill pipe. Note any discrepancies between the readings on the pump pressure gauge and the standpipe (drill pipe) pressure gauge. These pressure readings should be within 10 percent of each other. In addition, if a remotely controlled choke has been installed, the drill pipe pressure gauge on the choke-control panel must be checked to see that the panel has been connected correctly and that the gauge is accurate.

6. If the stack was completely filled with fluid before the test, leakage past the preventer ram blocks (ram rubbers or seal rings) will be evidenced by flow at the flow line. Leakage past the ram-shaft packing might cause a flow of fluid into the accumulator-unit reservoir.

7. Bleed the test pressure back through the pump, and open the lowermost ram preventer using the four-way valve at the accumulator unit.

e. **Testing the Upper Pipe-ram Preventer and the Standpipe Valve (Figure 27-4a)**

1. Close the upper pipe rams using the remote control panel at the driller's station.

2. Open the kill line control valve.

3. Build test pressure through the drill pipe, observing pressure on the pump pressure gauge, the choke manifold (casing) pressure gauge, and the standpipe (drill pipe) pressure gauge.

4. Close the standpipe valve and bleed the pressure at the pump. This should cause the check valve to close again. The pressure should drop to zero on the pump pressure gauge, but should remain constant at the standpipe pressure gauge and on the choke manifold pressure gauge. If pressure leakage occurs, close the lower kelly cock. If the pressure drop ceases at the choke manifold pressure gauge, but continues at a faster rate at the standpipe pressure gauge, the problem lies in the standpipe valve. If that situation does not occur, suspect the ram rubbers, the seal rings, or the ram-shaft packing in the upper pipe-ram preventer. Also, there may be concurrent leakage of the standpipe valve and the lower kelly cock, although this is unlikely.

f. **Testing the Upper Kelly Cock (Figure 27-4b)**

1. Close the upper kelly cock.

2. Open the standpipe valve. The pressure at the standpipe pressure gauge should drop to zero. Because the upper kelly cock has been closed (Step f1), little or no change should occur at the choke manifold pressure gauge.

3. If there is pressure loss, reclose the standpipe valve and watch the standpipe pressure gauge. If the gauge shows a pressure increase, the upper kelly cock is bypassing fluid.

4. Because it would probably be very difficult to open the upper kelly cock with test pressure on one side of the valve, it may necessary to bleed the pressure through the choke-manifold blowdown-line control valve and open the upper kelly cock.

g. **Testing the Lower Kelly Cock (Figure 27-4c)**

1. Close both the standpipe valve and the lower kelly cock. Then, rebuild the test pressure through the kill line, observing the pressure at the pump pressure gauge and/or the choke-manifold pressure gauge.

2. If there is pressure loss, check the standpipe pressure gauge. An increase at that gauge would indicate leakage past the lower kelly cock.

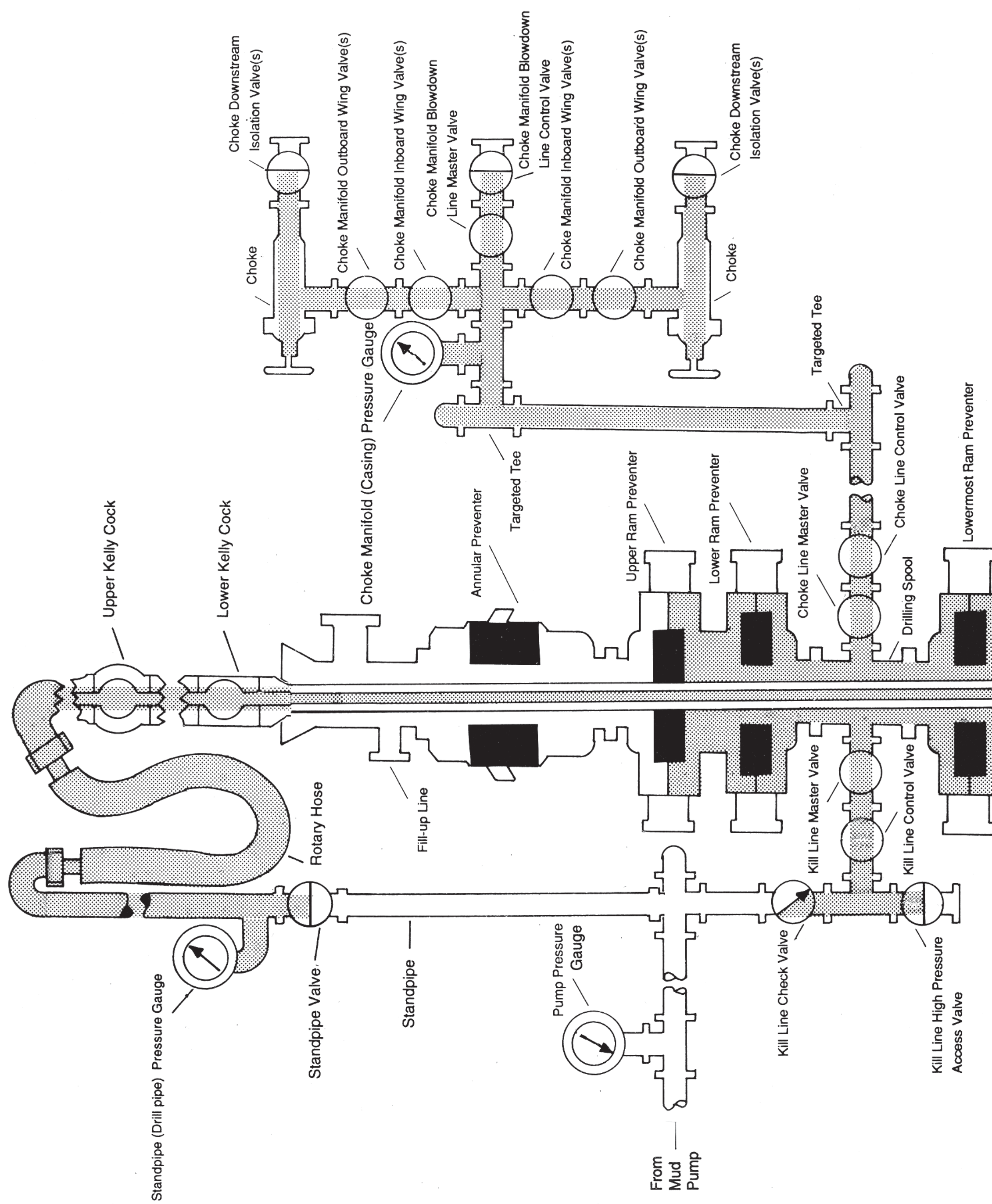


FIGURE 27-4a
Testing the Upper Pipe-ram Preventer and the Standpipe Valve.

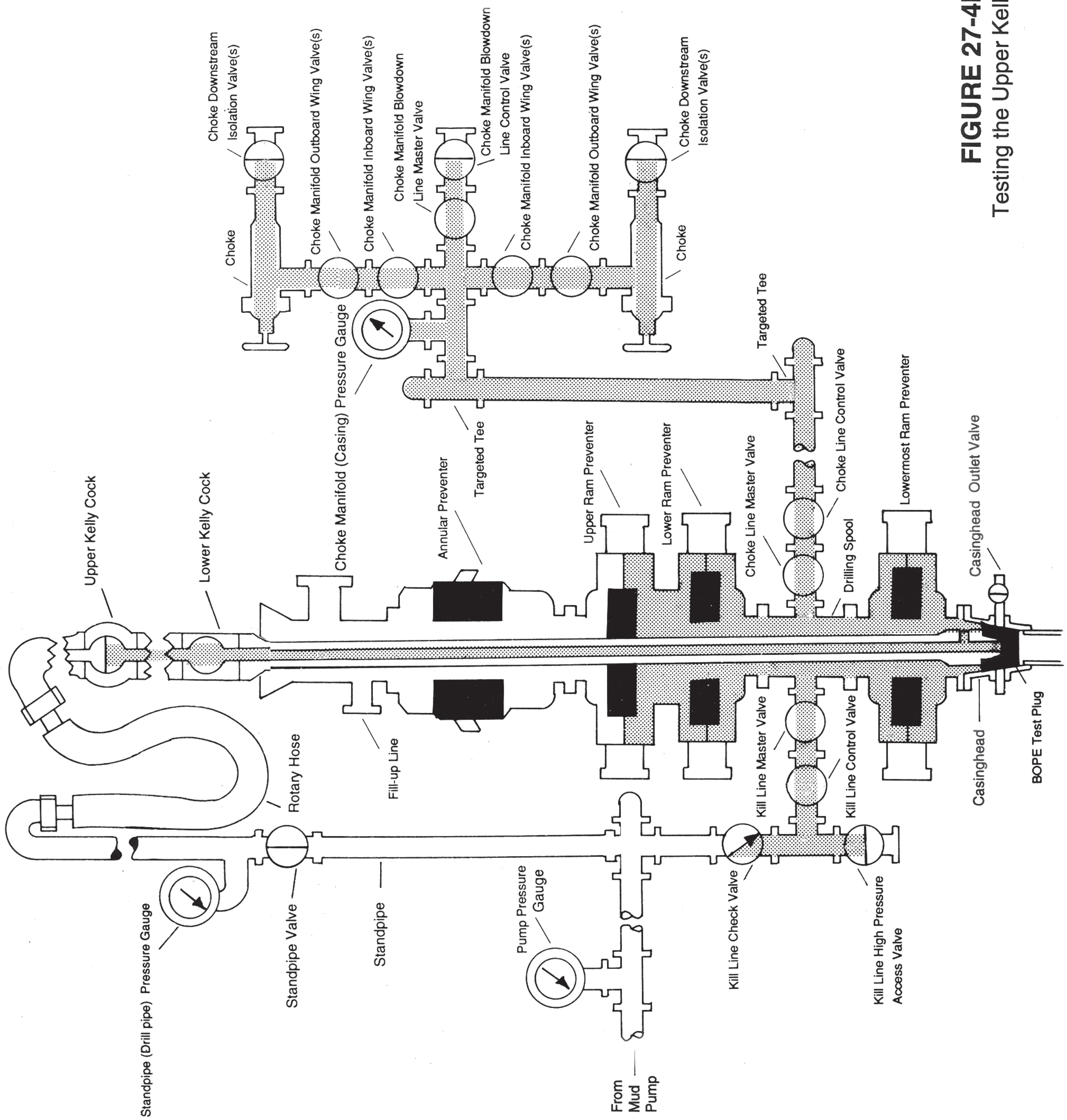


FIGURE 27-4b
Testing the Upper Kelly Cock.

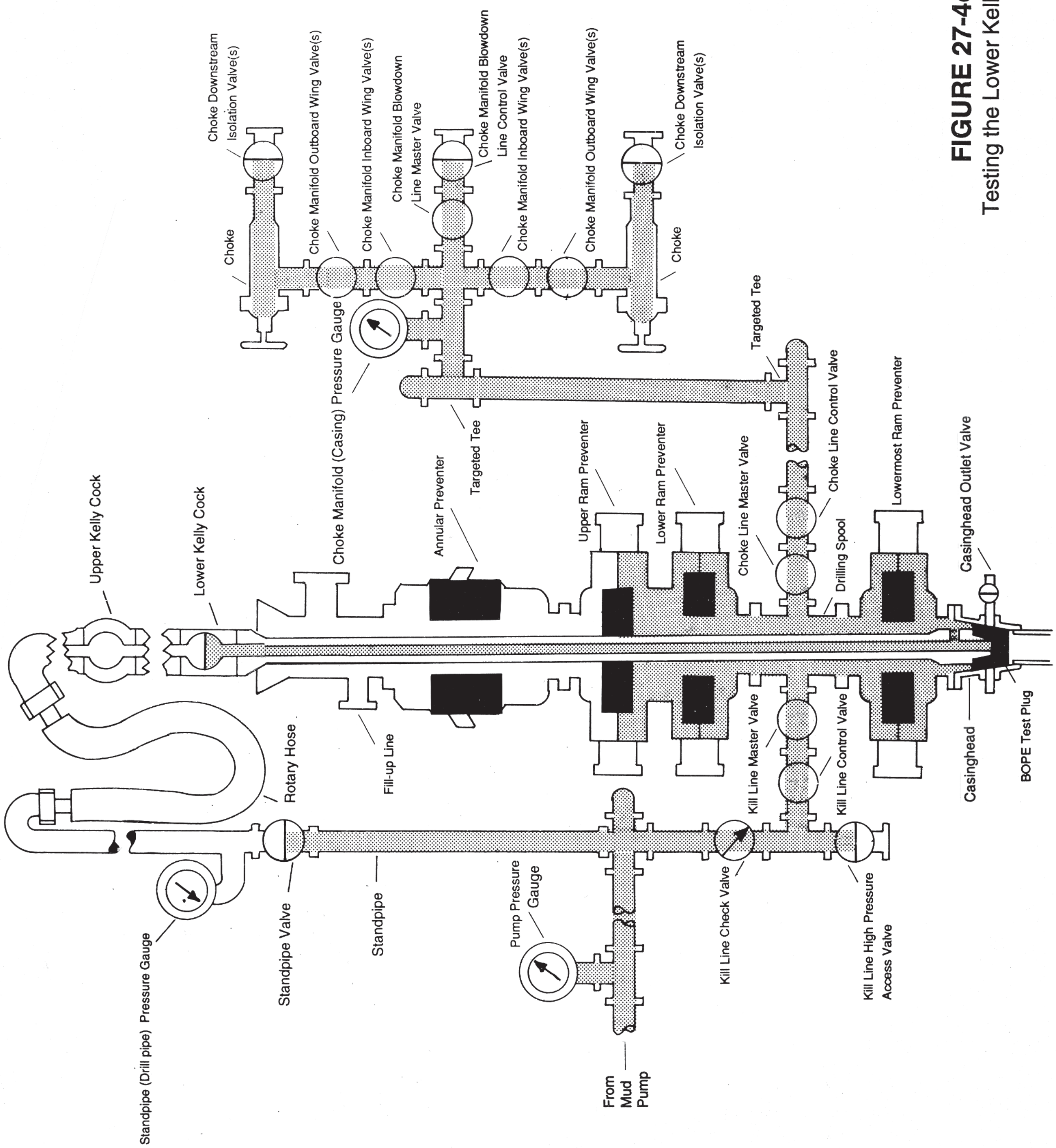


FIGURE 27-4c
Testing the Lower Kelly Cock.

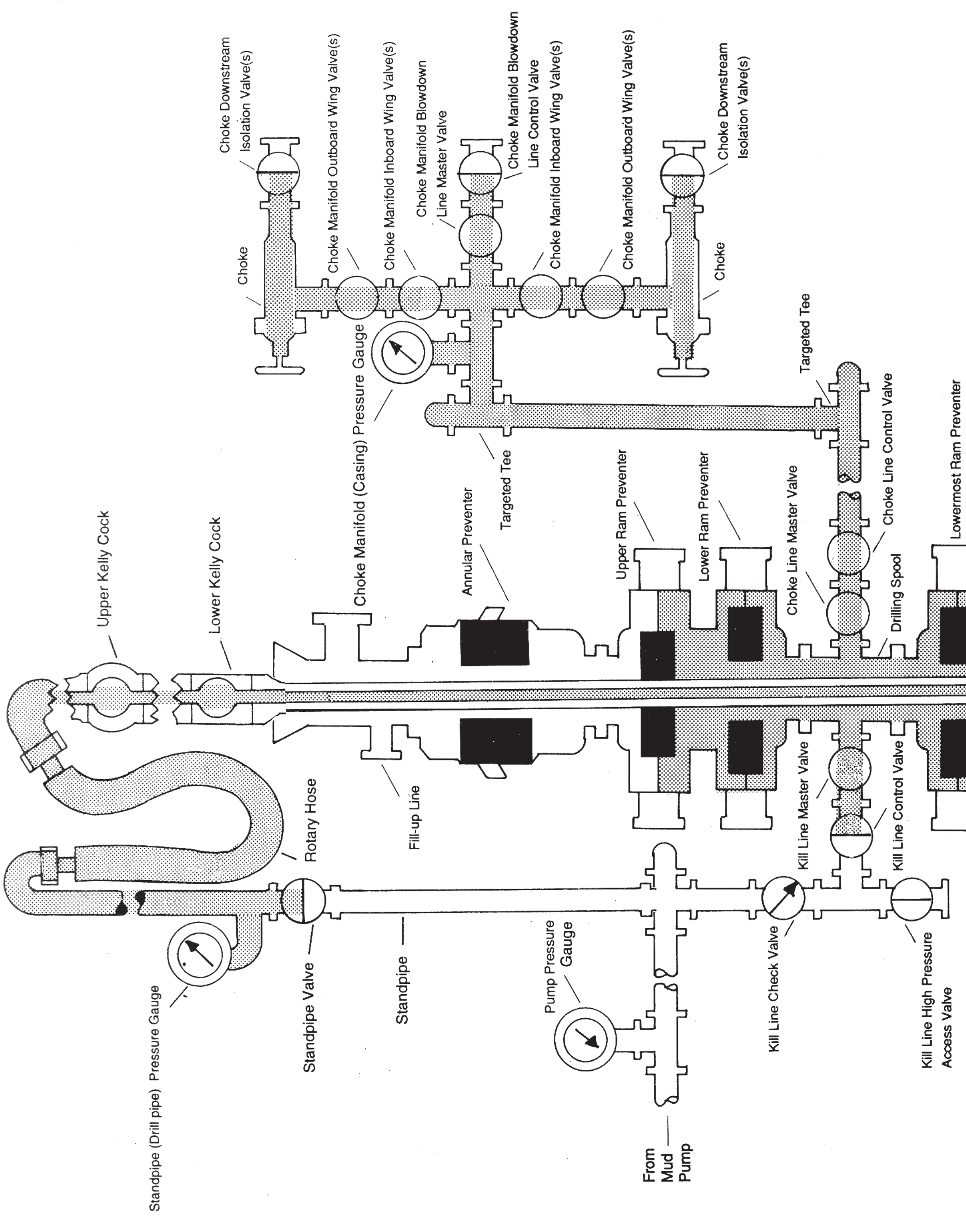


FIGURE 27-4d
Testing the Kill-line Control Valve.

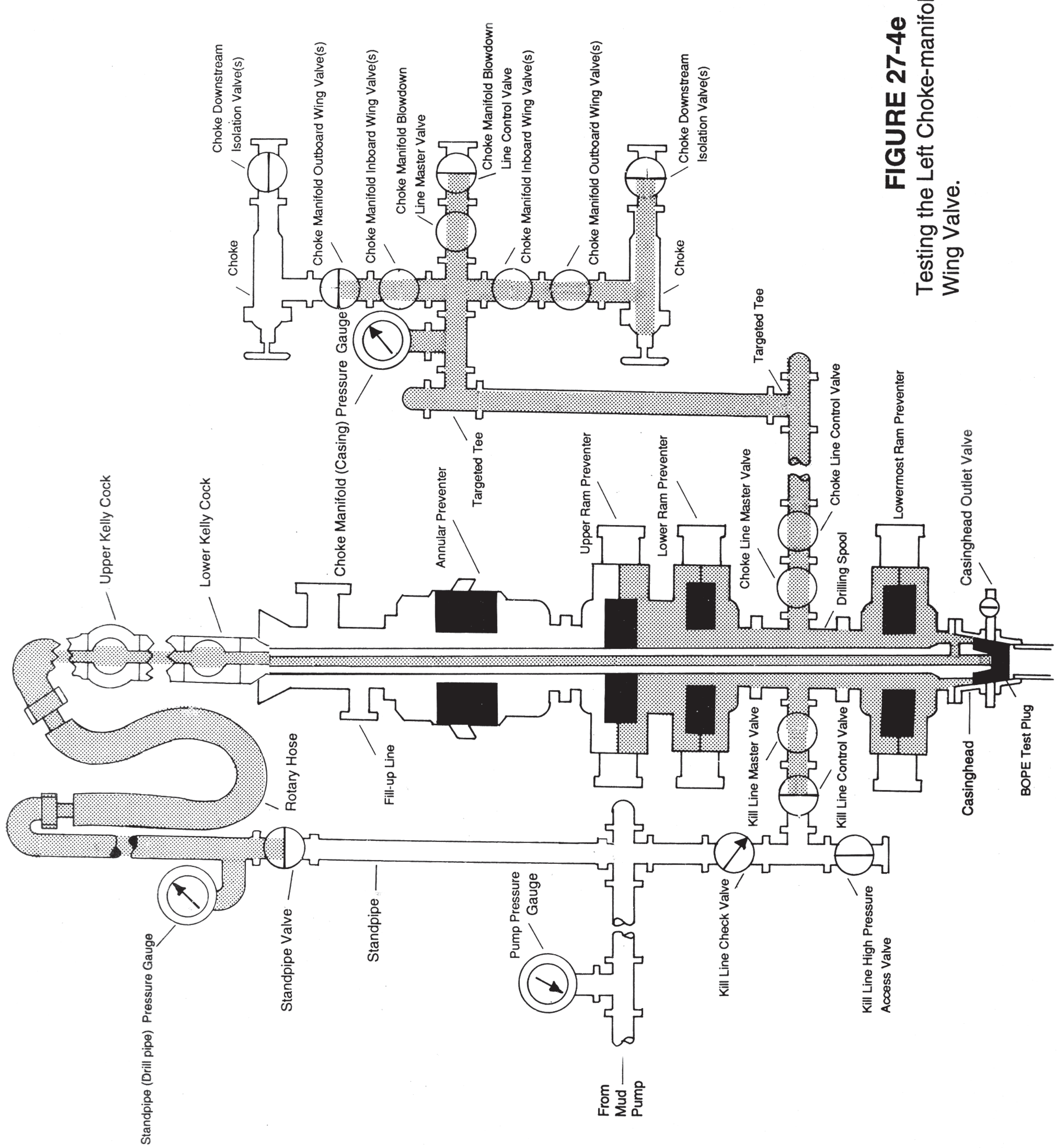


FIGURE 27-4e
Testing the Left Choke-manifold Outboard Wing Valve.

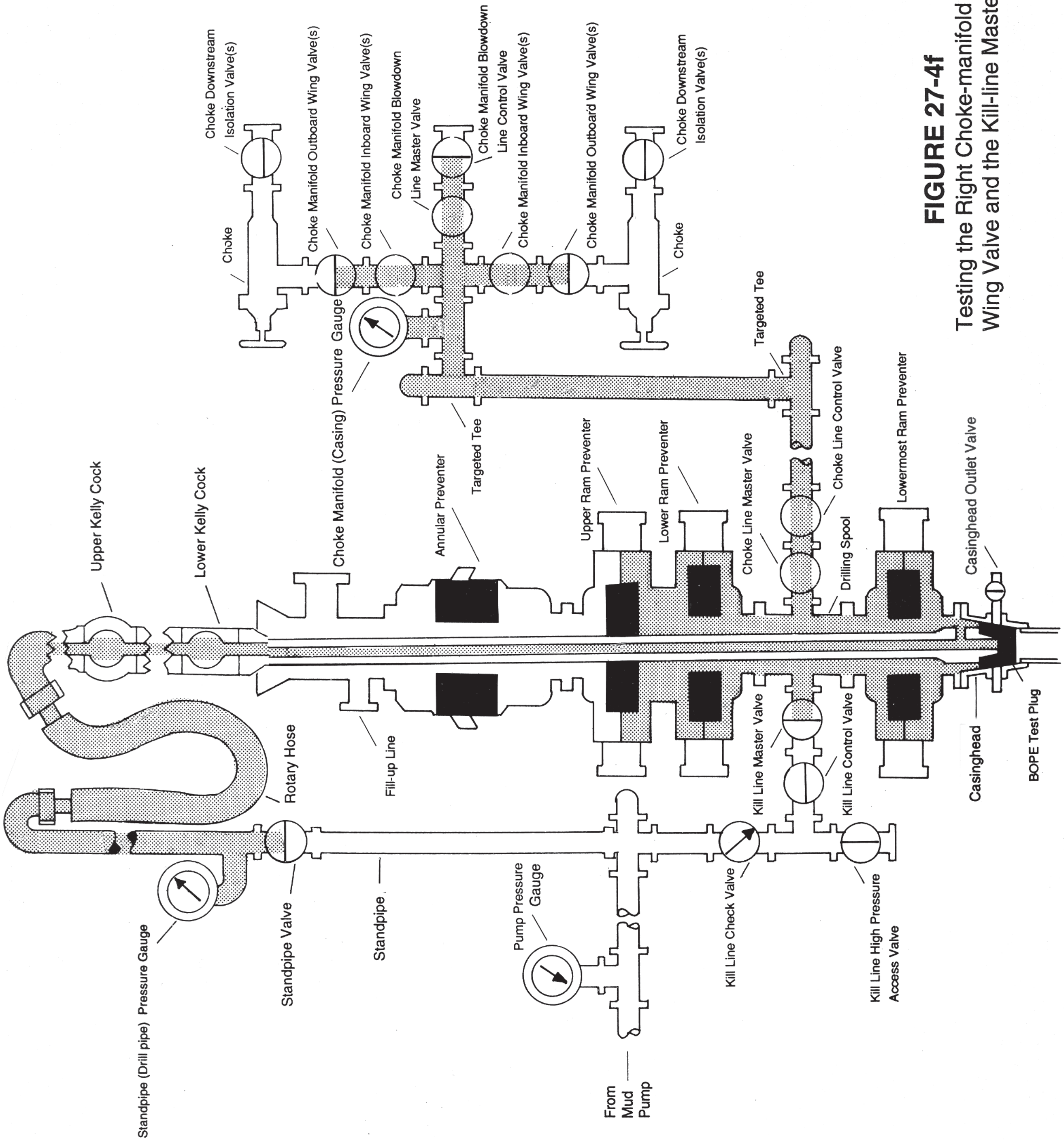


FIGURE 27-4f
Testing the Right Choke-manifold Outboard Wing Valve and the Kill-line Master Valve.

3. If there is no pressure loss, bleed the pressure through the choke-manifold blowdown-line control valve.

4. Open the lower kelly cock and the standpipe valve.

h. **Testing the Kill-line Control Valve (Figure 27-4d)**

1. Close the kill line control valve.

2. Rebuild the test pressure through the drill pipe, checking the pressure on the pump pressure gauge, the choke-manifold pressure gauge, and/or the standpipe pressure gauge.

3. Close the standpipe valve.

4. Bleed the pressure at the pump.

5. Open the kill-line high-pressure access valve. If the system does not include this valve, it will be necessary to dismantle the check valve to check the kill-line master valve and the kill-line control valve in the direction of blowout flow.

6. If there is pressure loss, check the opening at the kill-line high-pressure access valve or look into the check valve to see if the kill line control valve is leaking.

i. **Testing the Choke-manifold Outboard Wing Valve(s) and the Kill-line Master Valve (Figures 27-4e and 27-4f)**

1. Test the choke-manifold left-outboard wing valve by closing it and opening the left-choke downstream isolation valve. Watch the choke-manifold (casing) pressure gauge for a pressure drop.

2. Test the choke-manifold right-outboard wing valve by closing it and opening the right-choke, downstream isolation valve. Watch the choke manifold (casing) pressure gauge for a pressure drop.

3. Test the kill-line master valve by closing it and opening the kill-line control valve. Watch the opening at the kill-line high-pressure access valve for leakage.

j. **Testing the Choke Manifold Inboard Wing Valve(s) (Figures 27-4g and 27-4h)**

1. Test the choke-manifold left-inboard wing valve by closing it and opening the choke-manifold left-outboard wing valve. Watch the choke-manifold (casing) pressure gauge for pressure drop.

2. Test the choke-manifold right-inboard wing valve by closing it and opening the choke-manifold right-outboard wing valve. Watch the choke-manifold (casing) pressure gauge for pressure drop.

k. **Testing the Choke-manifold Blowdown-line Master Valve (Figure 27-4i)**

1. Close the choke-manifold blowdown-line master valve.

2. Open the choke-manifold blowdown-line control valve, watching the choke-manifold (casing) pressure gauge for a pressure drop.

l. **Testing the Choke-line Control Valve (Figure 27-4j)**

1. Close the choke-line control valve.

2. Open the choke-manifold blowdown-line master valve. The pressure should drop to zero on the choke-manifold (casing) pressure gauge and remain at the test-pressure value on the standpipe-pressure gauge.

m. **Testing the Choke-line Master Valve (Figure 27-4k)**

1. Close the choke-line master valve.

2. Open the choke-line control valve. Watch the standpipe pressure gauge for a pressure drop.

3. Open the standpipe valve and bleed the pressure back through the pump.

4. Open the upper pipe rams, using the four-way valve at the accumulator unit.

n. **Testing the Annular Preventer and the Connection of the Annular Preventer to the Upper Ram Preventer (Figure 27-5)**

1. Close the annular preventer from the remote station. Check the closing pressure at the applicable gauge on the accumulator unit.

2. Open the choke-line master valve and close the choke-manifold, inboard wing valves and the choke-manifold blowdown-line master valve so the standpipe pressure gauge and the choke-manifold pressure gauge can be compared dur-

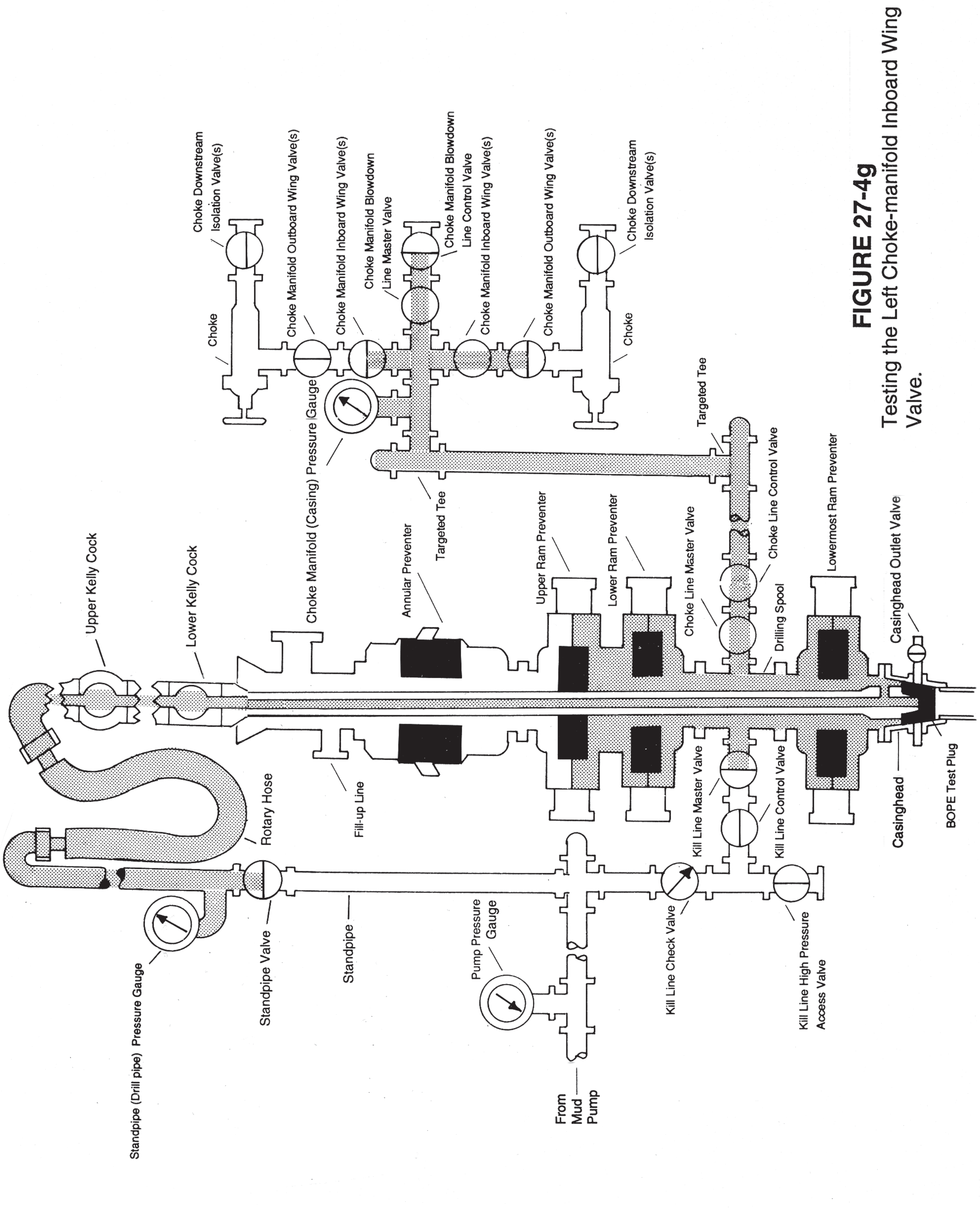


FIGURE 27-4g
Testing the Left Choke-manifold Inboard Wing Valve.

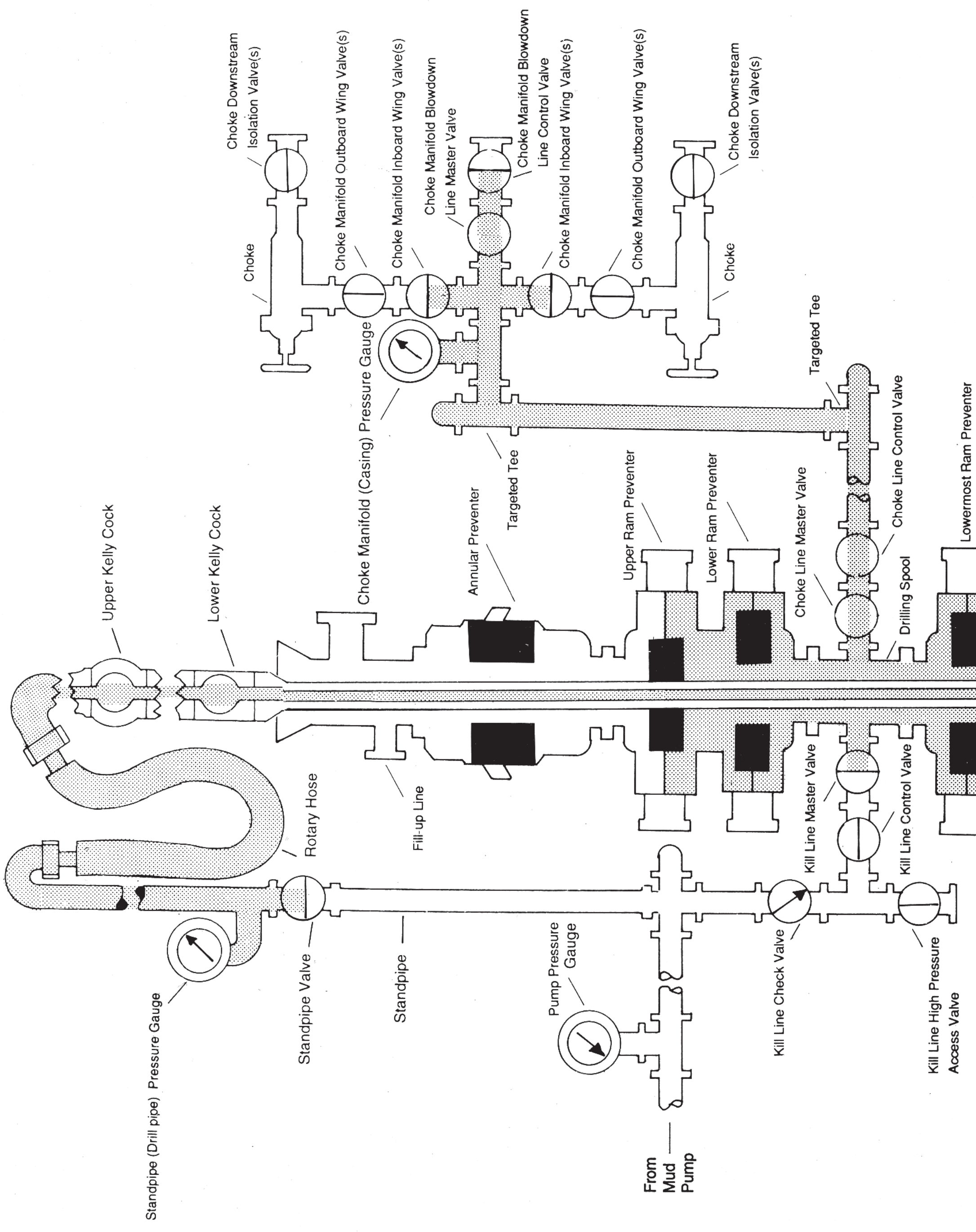


FIGURE 27-4h
Testing the Right Choke-manifold Inboard Wing Valve.

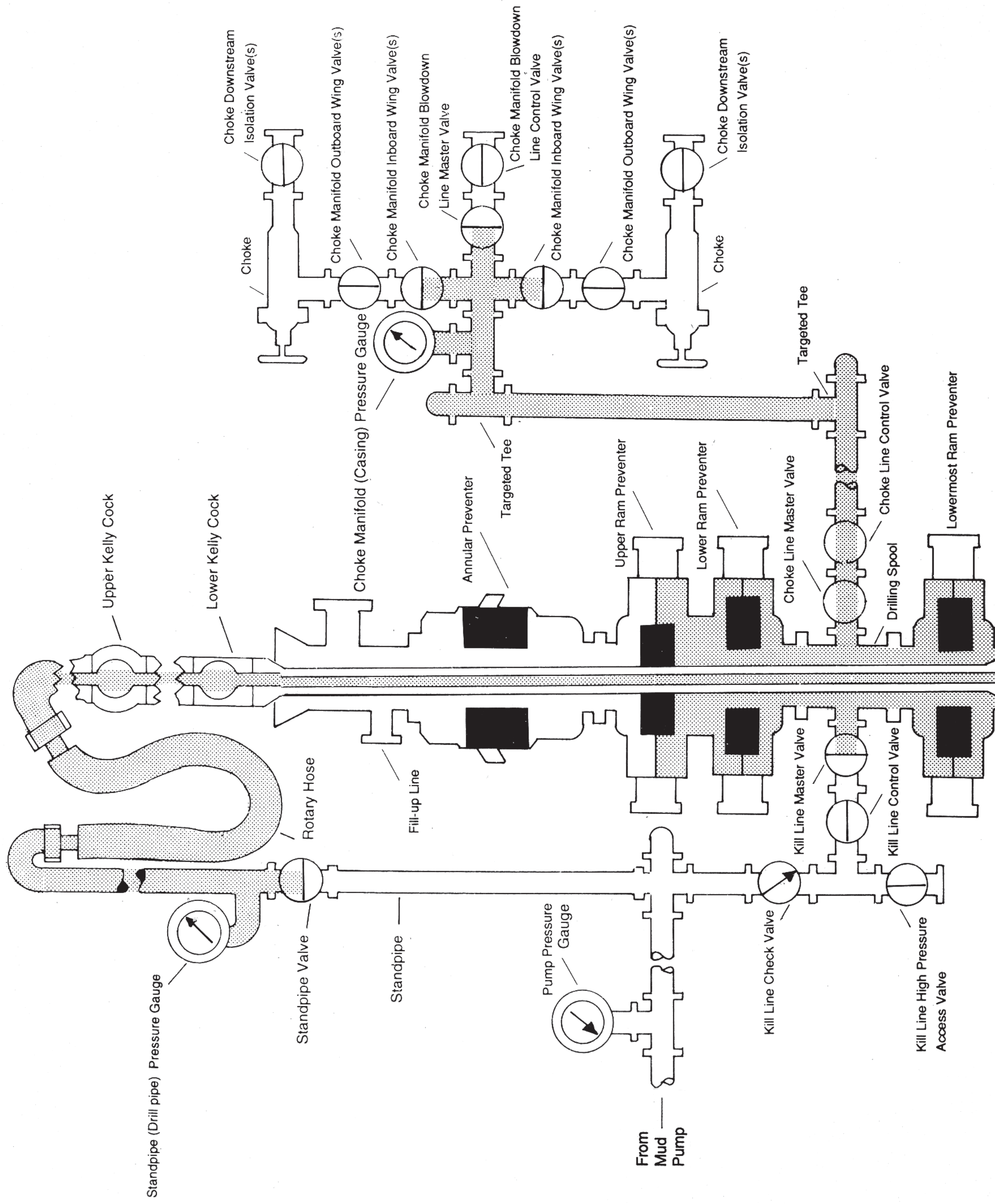


FIGURE 27-4i
Testing the Choke-manifold Blowdown-line Master Valve.

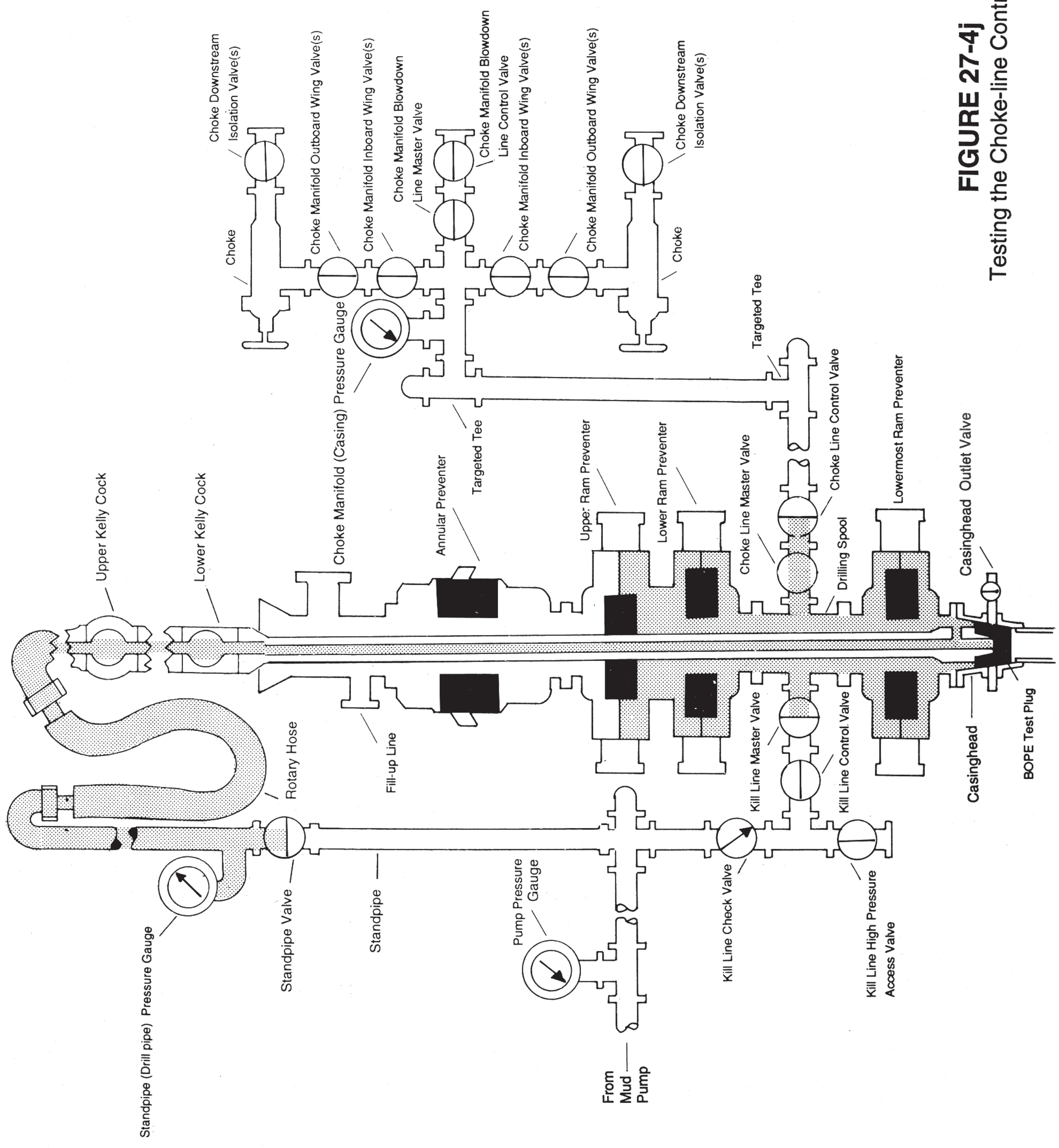


FIGURE 27-4j
Testing the Choke-line Control Valve.

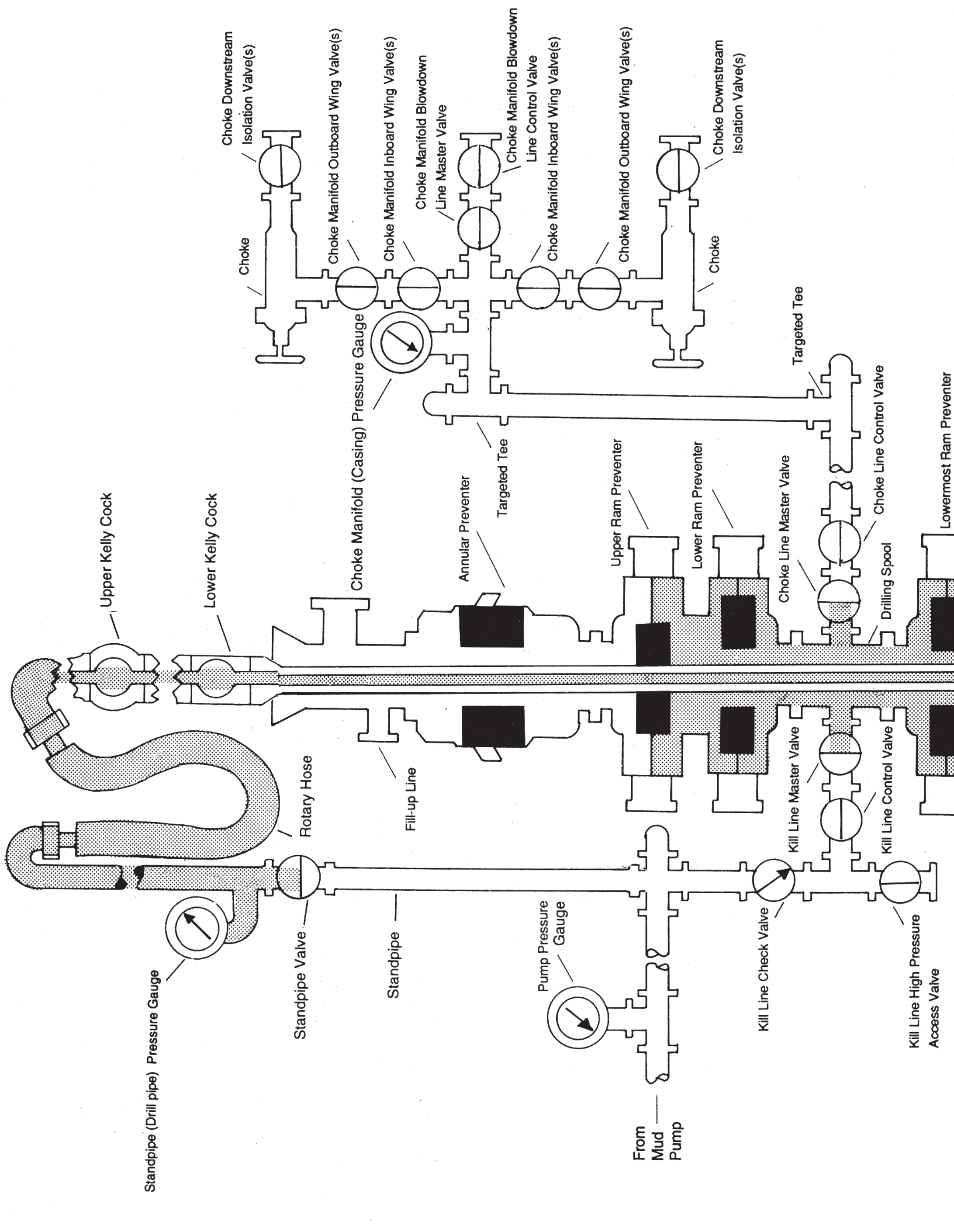


FIGURE 27-4k
Testing the Choke-line Master Valve.

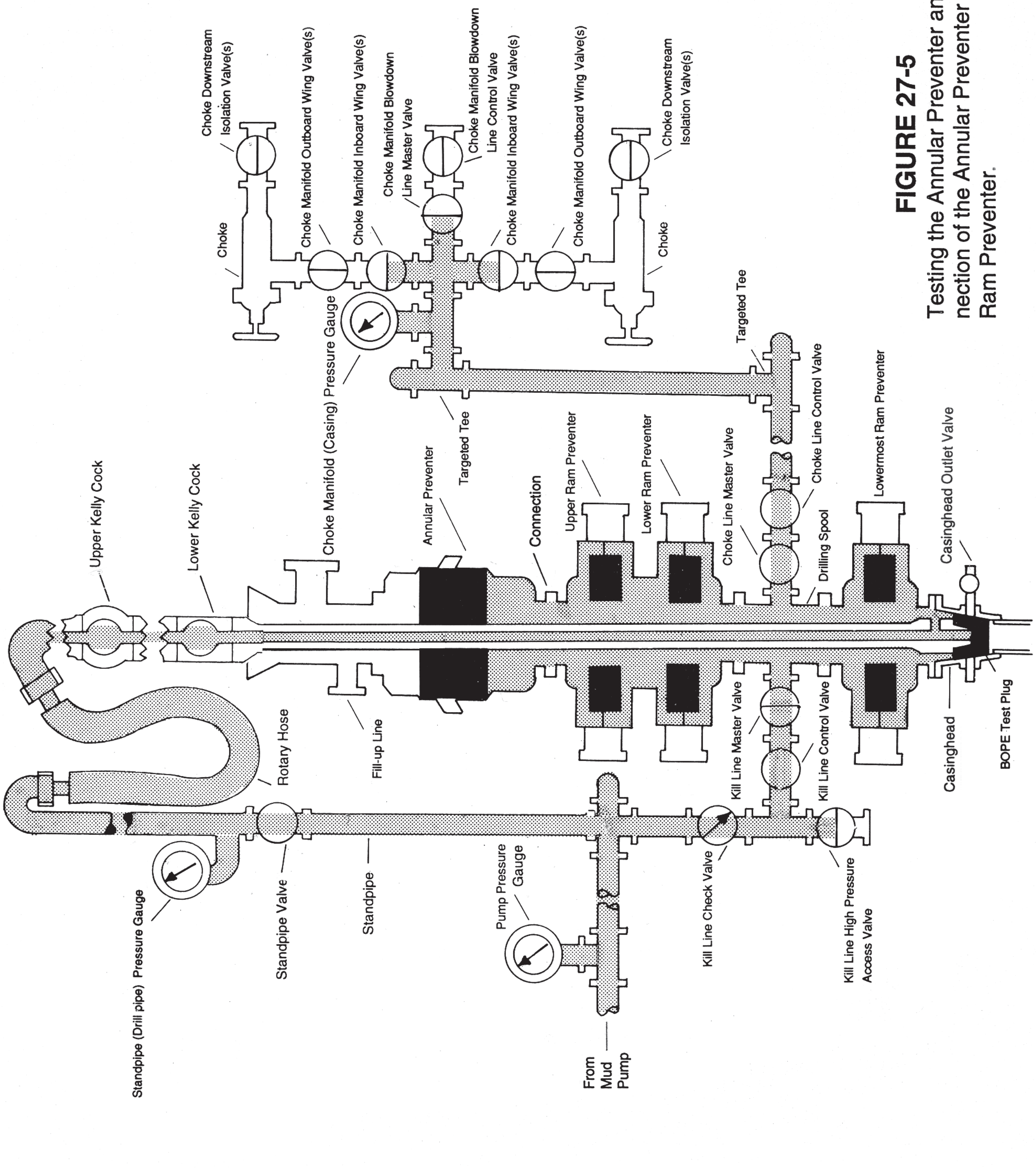


FIGURE 27-5
Testing the Annular Preventer and the Connection of the Annular Preventer to the Upper Ram Preventer.

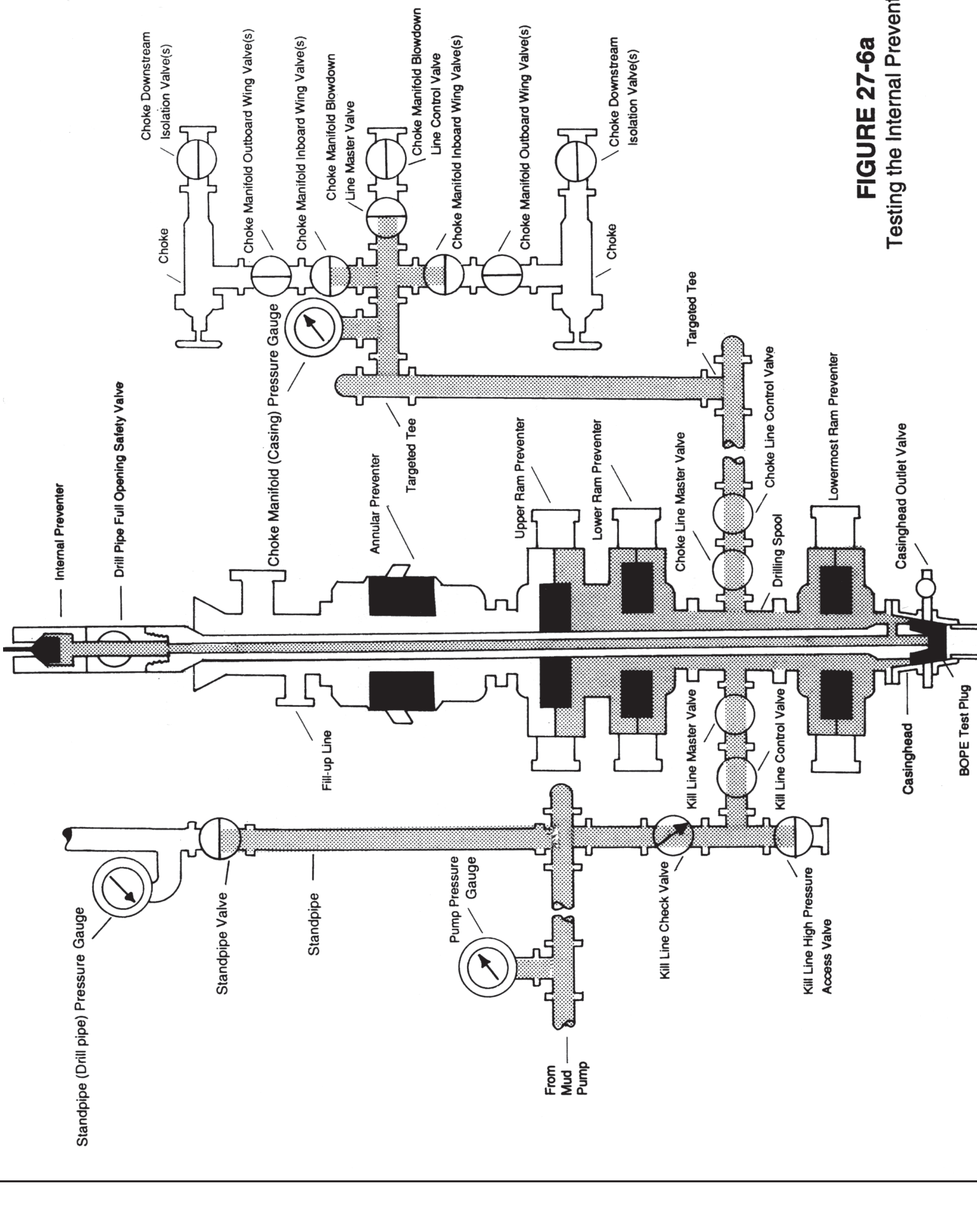


FIGURE 27-6a
Testing the Internal Preventer.

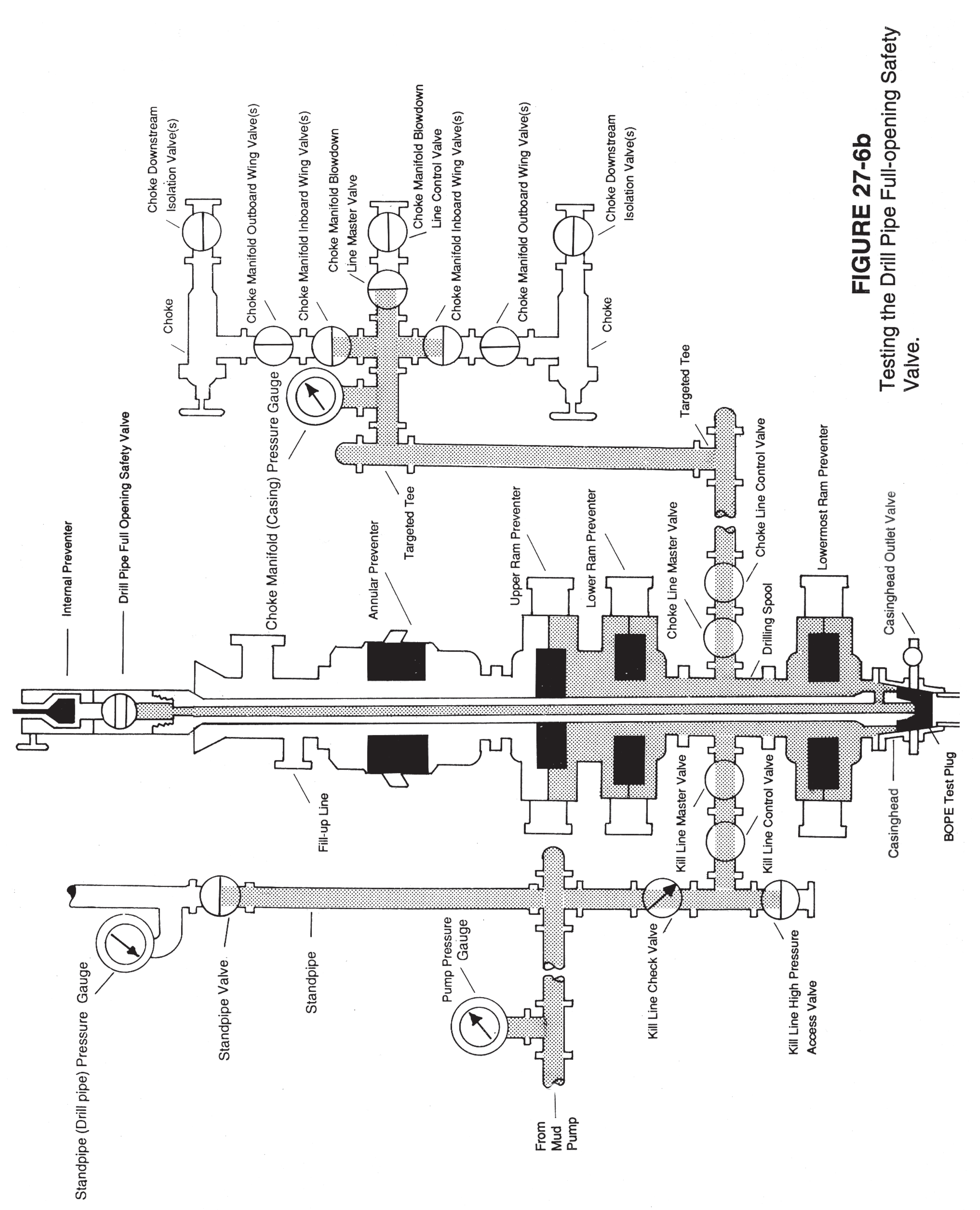


FIGURE 27-6b
Testing the Drill Pipe Full-opening Safety Valve.

ing the test, proving that the drill pipe pressure is being communicated through the weep hole to the BOP stack. The kill-line master valve is still closed from the previous testing.

3. Build test pressure through the drill pipe, reading the pressure at the standpipe pressure gauge and the choke-manifold pressure gauge. For annular preventers, the test pressure need not exceed 2,000 psi, regardless of the rated pressure of the preventer. If there is a pressure loss, suspect the packing element or the seal rings in the annular preventer. If the stack was filled with fluid prior to testing, leakage between the packing element and the drill pipe will cause flow at the flow line. Leakage past the seal rings may cause fluid returns to the accumulator-unit reservoir, but this does not always happen. This problem is best solved at the technical-service level.

4. Bleed the test pressure through the pump, ensuring that the standpipe pressure gauge and the choke-manifold pressure gauge both drop to zero before the annular preventer is opened.

5. Open the annular preventer, using the four-way valve at the accumulator unit.

o. **Testing the Internal Preventer and the Drill Pipe Full-opening Safety Valve (Figures 27-6a and 27-6b)**

1. Detach the kelly, close the standpipe valve, and affix the drill pipe full-opening safety valve to the drill pipe. Be sure that the valve is in the open position.

2. Affix the internal preventer to the drill pipe full-opening safety valve. Ensure the internal preventer is in the open position.

3. Open the kill-line master valve, and pump slowly through the kill line until the fluid overflows the internal preventer, ensuring that the drill pipe and the valves are full of fluid.

4. Close the drillpipe full-opening safety valve.

5. Apply pressure through the kill line until the test pressure is read on the pump pressure gauge and the choke-manifold (casing) pressure gauge. Watch the opening at the top of the internal preventer for leakage.

6. Bleed the pressure through the choke-manifold blowdown-line master valve.

7. Open the drill-pipe full-opening safety valve and close the internal preventer.

8. Again, apply pressure through the kill line until the test pressure is read on the pump pressure gauge and the choke manifold (casing) pressure gauge. Watch the opening at the top of the internal preventer for leakage.

9. Bleed the pressure through the choke-manifold blowdown-line master valve. Remove the internal preventer and the drill-pipe full-opening safety valve. Check to see that the internal preventer is stored in such a position or marked in such a way that it is unlikely that it would be the first piece of equipment installed in the working string in the event of a kick taken while tripping the pipe.

10. Remove the test joint of drill pipe and the BOPE test plug.

11. Return all valves to the drill-ahead condition (Figure 27-1).

5-4 SUBSEA BOPE INSPECTION AND TESTING

a. **Surface Inspection and Testing**

1. Prior to delivery to an offshore drilling unit, the subsea BOPE components must be tested as follows:

   a) Each BOPE component must be tested to its rated working pressure in test facilities under shop conditions.

   b) Following assembly and testing in the shop, the entire BOPE stack must be tested for proper operation using the actuating system (accumulator unit) that will be used when the equipment is installed.

      1) The operating system and control lines must be tested to 3,000 psi.

      2) Each preventer and high-pressure connector must be tested for low-pressure leakage at 200 psi and to the rated working pressure of the piece of equipment. (However, annular preventers need not be tested to pressures greater than 5,000 psi.)

The dates and results of the inspections and tests must be recorded on the shipping tags or delivery tickets.

2. After delivery to an offshore drilling unit, the unitized blowout prevention system must be tested on a test stump.

   a) Low-pressure and rated working-pressure tests of each component must be repeated and recorded properly in the driller's log.

   b) The test record must include opening and closing times, hydraulic fluid volumes required for each function, and pump-recovery times.

   Subsequent test-stump pressures should be limited to 70 percent of the rated working pressure of the blowout preventer stack, or the anticipated surface pressure, whichever is greater. Further testing to the full rated working pressure of the components should be limited to one test following any work that requires breaking a pressure seal in the assembly.

3. Before installing the BOPE array on a well, the accumulator unit must be tested for precharge pressure and recharging pump capability.

4. The entire BOPE system must be inspected visually before installation, and a record of the inspection recorded in the driller's log.

b. **Subsea Pressure Testing.** Pressure testing of each of the subsea stack components must be performed as follows:

   1. After installation.

   2. After setting casing.

   3. Before drilling into any known or suspected high-pressure zones.

   4. At regular intervals during drilling operations, or at least once each week.

   5. Following any repair or replacement that necessitates breaking a pressure seal in the assembly.

   Following installation of the BOPE stack on the ocean floor, each component, including the high-pressure connectors, must be pressure-tested individually at low pressure (200 psi) and to 70 percent of the rated working pressure of the ram preventers, or to the maximum pressure expected in the upper part of the casing, whichever is greater. Subsequent pressure tests may be limited to 70 percent of the minimum internal yield strength of the upper part of the casing, provided the test pressure equals or exceeds the maximum pressure anticipated inside the upper part of the casing during drilling or completion operations.

   The annular preventer is exempted from this requirement. Following installation on the ocean floor, the annular preventer may be tested at 50 percent of its rated working pressure to minimize packing-element wear or damage. (A test plug or cup-type tester should be used.)

   A subsea test tree must be used in the blowout preventer stack while performing drill stem or production tests from mobile drilling rigs.

c. **Subsea Preventer Actuation Testing.** In addition to the pressure testing just outlined, each of the preventers in the subsea stack must be actuated according to the following schedule:

   1. Each of the pipe-ram preventers must be tested for actuation before pulling drill pipe out of the hole on each trip, or at least once each 24 hours.

   2. The annular preventers need not be actuated during this pretrip function testing as long as they are being operated during the required weekly pressure tests or at an interval not greater than once each seven days.

   3. Periodic actuation-testing is not required for the blind or blind-shear rams. These rams need only be tested when installed and prior to drilling out after each casing string has been set.

d. **Testing the Subsea Actuating System.** The subsea BOPE system is dependent on surface-actuated hydraulic and/or electric controls. The design of this actuating system is governed by water depth and environmental conditions. It is important to pressure test and function test the system concurrently with the blowout preventers and connectors.

   1. The system must have an adequate backup system to operate each critical function.

   2. Operation of individual components of the subsea BOPE array must be alternated frequently enough between control pods and remote operating panels to ensure that each pod and all operating panels are functioning properly.

3. Testing must be conducted at staggered intervals to allow each drilling crew to perform the tests.

e. **Testing the Auxiliary Equipment**

1. The upper and lower kelly cocks, drill pipe safety valve, casing safety valve, and inside blowout preventer must be tested at the same time and to the same pressures as the ram-type blowout preventers.

2. Each choke-manifold valve, adjustable choke, subsea kill- and choke-line valve, upper- and lower-kelly cock, drill-pipe safety valve, and internal preventer must be operated daily.

3. Following each operational test, the choke manifold and subsea kill- and choke-line valves must be flushed with water to prevent the lines and valves from plugging.

4. The diverter and its vent lines and valves must be checked daily for plugging by drill cuttings or other debris.

APPENDIX A

General Operating Specifications For Ram–type Preventers

MODEL OR TYPE	B.O.P. SIZE Inches	WORKING PRESSURE Max. PSI	VERT. BORE Inches	HYDRAULIC OPERATOR PSI*	GALS. TO CLOSE	GALS. TO OPEN	** CLOSE RATIO	** OPEN RATIO
BOWEN TOOLS, INC., Houston, Texas								
51922	2½ Single	6,000	2½	780	.17	.16	7.9:1	Not Applicable. Well pressure must be equalized across rams.
51923	2½ Single	10,000	2½	1,300	.19	.19	7.9:1	
51924	2½ Twin	5,000	2½	692	.36	.28	7.9:1	
60701	2½ Twin	10,000	2½	1,001	.43	.35	7.9:1	
50460	2 9/16 Single	15,000	2 9/16	1,000	.3	.3	8.18:1	
51926	3 Single	5,000	3	369	.30	.22	13.2:1	
51927	3 Single	10,000	3	738	.30	.22	13.2:1	
51928	3 Twin	5,000	3	369	.54	.49	13.2:1	
51929	3 Twin	10,000	3	738	.54	.49	13.2:1	
61040	4 Single	5,000	4	555	.91	.81	15.3:1	
61044	4 Single	10,000	4	1,110	.91	.81	15.3:1	
61048	4 Twin	5,000	4	555	1.81	1.62	15.3:1	
61050	4 Twin	10,000	4	1,110	1.81	1.62	15.3:1	
47034	4 1/16 Single	10,000	4 1/16	1,000	.43	.34	13.6:1	
60467	4 1/16 Single	15,000	4 1/16	3,000	.43	.34	13.6:1	
61053	4½ Single	3,000	4½	370	.91	.81	15.3:1	
61055	4½ Single	10,000	4½	1,110	.91	.81	15.3:1	
61057	4½ Twin	5,000	4½	555	1.83	1.64	15.3:1	
61060	4½ Twin	10,000	4½	1,110	1.83	1.64	15.3:1	
51938	5½ Single	3,000	5½	240	1.51	1.37	20.8:1	
63642	7 1/16 Single	10,000	7 1/16	900	.74	.75	10.9:1	
CAMERON IRON WORKS, Houston, Texas								
U	6	3,000	7 1/16	1,500/3,000	1.33	1.28	7:1	2.3:1
U	6	5,000	7 1/16	1,500/3,000	1.33	1.28	7:1	2.3:1
U	7 1/16	10,000	7 1/16	1,500/3,000	1.33	1.28	7:1	2.3:1
U	7 1/16	15,000	7 1/16	1,500/3,000	1.33	1.28	7:1	2.3:1
U	10	3,000	11	1,500/3,000	3.36	3.20	7:1	2.3:1
U	10	5,000	11	1,500/3,000	3.36	3.20	7:1	2.3:1
U	11	10,000	11	1,500/3,000	3.36	3.20	7:1	2.3:1
U	11	15,000	11	1,500/3,000	3.36	3.20	7:1	2.3:1
U	12	3,000	13⅝	1,500/3,000	5.80	5.45	7:1	2.3:1
U	13⅝	5,000	13⅝	1,500/3,000	5.80	5.45	7:1	2.3:1
U	13⅝	10,000	13⅝	1,500/3,000	5.80	5.45	7:1	2.3:1
U	13⅝	15,000	13⅝	1,500/3,000	11.3	11.7	6.6:1	2.3:1
U	16¾	3,000	16¾	1,500/3,000	9.8	10.6	6.7:1	1.4:1
U	16¾	5,000	16¾	1,500/3,000	9.8	10.6	6.7:1	1.4:1
U	18¾	10,000	18¾	1,500/3,000	23	24.9	7.4:1	
U	20	2,000	20¾	1,500/3,000	8.40	7.85	7:1	1.2:1
U	20	3,000	20¾	1,500/3,000	8.40	7.85	7:1	1.2:1
U	21¼	2,000	21¼	1,500/3,000	8.40	7.85	7:1	1.2:1
U	21¼	7,500	21¼	1,500/3,000	20.4	17.8	5.5:1	
U	21¼	10,000	21¼	1,500/3,000	26.5	24.1	7.2:1	
U	26¾	2,000	26¾	1,500/3,000	10.4	9.85	7:1	.63:1
U	26¾	3,000	26¾	1,500/3,000	10.4	9.85	7:1	.63:1
U-Blind	13⅝	5,000	13⅝	1,500/2,500	11.6	10.9	14:1	2.3:1
Ram with	13⅝	10,000	13⅝	1,500/2,500	11.6	10.9	14:1	2.3:1
Shear	16¾	3,000	16¾	1,500/2,500	10.8	11.7	9:1	1.4:1
Booster	16¾	5,000	16¾	1,500/2,500	10.8	11.7	9:1	1.4:1
	20	2,000	20¾	1,500/2,500	16.8	15.7	14:1	1.2:1
	20	3,000	20¾	1,500/2,500	16.8	15.7	14:1	1.2:1
QRC	6	3,000	7 1/16	1,500/3,000	0.81	0.95	7.75:1	1.5:1
QRC	6	5,000	7 1/16	1,500/3,000	0.81	0.95	7.75:1	1.5:1
QRC	8	3,000	9	1,500/3,000	2.36	2.70	9.05:1	1.83:1

Note: Adapted from *Quick Reference Tables,* Oilfield Division, Stewart & Stevenson, Inc. Figures shown are 1974–75 data reflecting information received from manufacturers.

TYPE OR MODEL	B.O.P. SIZE Inches	WORKING PRESSURE Max. PSI	VERT. BORE Inches	HYDRAULIC OPERATOR PSI*	GALS. TO CLOSE	GALS. TO OPEN	** CLOSE RATIO	** OPEN RATIO
CAMERON IRON WORKS, Houston, Texas (Continued)								
QRC	8	5,000	9	1,500/3,000	2.36	2.70	9.05:1	1.83:1
QRC	10	3,000	11	1,500/3,000	2.77	3.18	9.05:1	1.21:1
QRC	10	5,000	11	1,500/3,000	2.77	3.18	9.05:1	1.21:1
QRC	12	3,000	13⅝	1,500/3,000	4.42	5.10	8.64:1	1.07:1
QRC	16	2,000	16¾	1,500/3,000	6.0	7.05	8.64:1	0.62:1
QRC	18	2,000	17¾	1,500/3,000	6.0	7.05	8.64:1	0.62:1
QRC	20	2,000	17¾	1,500/3,000	6.0	7.05	8.64:1	0.62:1
SS	6	3,000	7 1/16	1,500/3,000	0.8	0.7	3.8:1	1:1
SS	6	5,000	7 1/16	1,500/3,000	0.8	0.7	3.8:1	1:1
SS	8	3,000	9	1,500/3,000	1.5	1.3	3.9:1	1:1
SS	8	5,000	9	1,500/3,000	1.5	1.3	3.9:1	1:1
SS	10	3,000	11	1,500/3,000	1.5	1.3	3.9:1	1:1
SS	10	5,000	11	1,500/3,000	1.5	1.3	3.9:1	1:1
SS	12	3,000	13⅝	1,500/3,000	2.9	2.5	3.7:1	1:1
SS	14	5,000	13⅝	1,500/3,000	2.9	2.5	3.7:1	1:1
Type F	6	3,000	7 1/16	500/1,500	1.5	2.3	VARIABLE	4.5:1
with	6	5,000	7 1/16	500/1,500	1.5	2.3		4.5:1
Type W_2	7	10,000	7 1/16	500/1,500	1.5	2.3		4.5:1
Opr.	7	15,000	7 1/16	500/1,500	1.5	2.3		4.5:1
	8	3,000	9	500/1,500	2.8	3.7		2.5:1
	8	5,000	9	500/1,500	2.8	3.7		2.5:1
	10	3,000	11	500/1,500	2.8	3.7		2.5:1
	10	5,000	11	500/1,500	2.8	3.7		2.5:1
	11	10,000	11	500/1,500	2.8	3.7		2.5:1
	12	3,000	13⅝	500/1,500	4.1	5.3		2:1
	14	5,000	13⅝	500/1,500	4.1	5.3		2:1
	16	2,000	16¾	500/1,500	5.0	6.0		2:1
	16	3,000	16¾	500/1,500	5.0	6.0		2:1
	20	2,000	20¼	500/1,500	5.0	6.0		2:1
	20	3,000	20¼	500/1,500	5.0	6.0		2:1
Type F	6	3,000	7 1/16	500/1,500	2.3	3.05	VARIABLE	4.5:1
with	6	5,000	7 1/16	500/1,500	2.3	3.05		4.5:1
Type W	7	10,000	7 1/16	500/1,500	2.3	3.05		4.5:1
Opr.	7	15,000	7 1/16	500/1,500	2.3	3.05		4.5:1
	8	3,000	9	500/1,500	3.7	4.6		2.5:1
	8	5,000	9	500/1,500	3.7	4.6		2.5:1
	10	3,000	11	500/1,500	3.7	4.6		2.5:1
	10	5,000	11	500/1,500	3.7	4.6		2.5:1
	11	10,000	11	500/1,500	3.7	4.6		2.5:1
	12	3,000	13⅝	500/1,500	6.8	8.1		2:1
	14	5,000	13⅝	500/1,500	6.8	8.1		2:1
	16	2,000	16¾	500/1,500	7.6	9.1		2:1
	16	3,000	16¾	500/1,500	7.6	9.1		2:1
	20	2,000	20¼	500/1,500	7.6	9.1		2:1
	20	3,000	20¼	500/1,500	7.6	9.1		2:1

*Lower pressures for normal use, higher pressures for emergency only.

**

$$\text{Closing Ratio} = \frac{\text{Well Pressure}}{\text{Hydraulic Pressure}}$$

$$\text{Opening Ratio} = \frac{\text{Hydraulic Pressure}}{\text{Well Pressure}}$$

General Operating Specifications For Ram-type Preventers

MODEL OR TYPE	B.O.P. SIZE Inches	WORKING PRESSURE Max. PSI	VERT. BORE Inches	HYDRAULIC OPERATOR PSI*	GALS. TO CLOSE	GALS. TO OPEN	** CLOSE RATIO	** OPEN RATIO
CAMERON IRON WORKS, Houston, Texas (Continued)								
Type F with Type L Opr.	6	3.000	7 1/16	250/1,500	3.97	3.46	VARIABLE	4.9:1
	6	5,000	7 1/16	250/1,500	3.97	3.46		4.9:1
	7	10,000	7 1/16	250/1,500	3.97	3.46		4.9:1
	7	15,000	7 1/16	250/1,500	3.97	3.46		4.9:1
	8	3,000	9	250/1,500	6.85	6.19		3.44:1
	8	5,000	9	250/1,500	6.85	6.19		3.44:1
	10	3,000	11	250/1,500	6.85	6.19		3.44:1
	10	5,000	11	250/1,500	6.85	6.19		3.44:1
	11	10,000	11	250/1,500	6.85	6.19		3.44:1
	12	3,000	13⅝	250/1,500	10.30	9.38		2.3:1
	14	5,000	13⅝	250/1,500	10.30	9.38		2.3:1
	16	2,000	16¾	250/1,500	11.71	10.66		2.3:1
	16	3,000	16¾	250/1,500	11.71	10.66		2.3:1
	20	2,000	20¼	250/1,500	11.71	10.66		2.3:1
	20	3,000	20¼	250/1,500	11.71	10.66		2.3:1
Type F with Type H Opr.	6	3,000	7 1/16	1,000/5,000	0.52	1.05	VARIABLE	1.5:1
	6	5,000	7 1/16	1,000/5,000	0.52	1.05		1.5:1
	7	10,000	7 1/16	1,000/5,000	0.52	1.05		1.5:1
	7	15,000	7 1/16	1,000/5,000	0.52	1.05		1.5:1
	8	3,000	9	1,000/5,000	0.90	1.80		1:1
	8	5,000	9	1,000/5,000	0.90	1.80		1:1
	10	3,000	11	1,000/5,000	0.90	1.80		1:1
	10	5,000	11	1,000/5,000	0.90	1.80		1:1
	11	10,000	11	1,000/5,000	0.90	1.80		1:1
	12	3,000	13⅝	1,000/5,000	1.52	2.70		2/3:1
	14	5,000	13⅝	1,000/5,000	1.52	2.70		2/3:1
	16	2,000	16¾	1,000/5,000	1.73	3.08		2/3:1
	16	3,000	16¾	1,000/5,000	1.73	3.08		2/3:1
	20	2,000	20¼	1,000/5,000	1.73	3.08		2/3:1
	20	3,000	20¼	1,000/5,000	1.73	3.08		2/3:1
DRESSER OME (Guiberson), Dallas, Texas								
Type H Hyd. Cyl.	6	3,000	N.A.	2,000	1.1	.94	6.5:1	1:1
	8	2,000	N.A.	2,000	1.1	.94	6.5:1	1:1

*Lower pressures for normal use, higher pressures for emergency only.

**

$$\text{Closing Ratio} = \frac{\text{Well Pressure}}{\text{Hydraulic Pressure}}$$

$$\text{Opening Ratio} = \frac{\text{Hydraulic Pressure}}{\text{Well Pressure}}$$

Note: Adapted from *Quick Reference Tables,* Oilfield Division, Stewart & Stevenson, Inc. Figures shown are 1974–75 data reflecting information received from manufacturers.

MODEL OR TYPE	B.O.P. SIZE INCHES	W.P. MAX PSI	VERT BORE Inches	HYD. OPER. PSI	GALS. TO CLOSE	GALS. TO OPEN	** CLOSE RATIO	** OPEN RATIO
RUCKER-SHAFFER, Houston, Texas								
LWS W/ LOCKING MANUAL SCREW	4 1/16	10,000	4 1/16	1,500/3,000	.50	.47	8.45:1	4.74:1
	6	3,000	7 1/16	1,500/3,000	1.20	1.00	4.44:1	1.82:1
	6	5,000	7 1/16	1,500/3,000	1.20	1.00	4.45:1	1.82:1
	7 1/16	10,000	7 1/16	1,500/3,000	6.35	5.89	10.63:1	19.40:1
	7 1/16	15,000	7 1/16	1,500/3,000	6.35	5.89	10.63:1	19.40:1
	8	3,000	9	1,500/3,000	2.58	2.26	5.58:1	3.00:1
	8	5,000	9	1,500/3,000	2.58	2.26	5.58:1	3.00:1
	9	10,000	9	1,500/3,000	2.44	2.14	5.58:1	1.69:1
	10	3,000	11	1,500/3,000	1.75	1.45	4.45:1	1.16:1
	10	5,000	11	1,500/3,000	2.98	2.62	5.58:1	2.10:1
	11	10,000	11	1,500/3,000	3.62	3.31	7.83:1	2.20:1
	12	3,000	13⅝	1,500/3,000	3.36	2.95	5.58:1	1.75:1
	13⅝	5,000	13⅝	1,500/3,000	3.36	2.95	5.58:1	1.75:1
	13⅝	10,000	13⅝	1,500/3,000	10.59	9.82	10.63:1	3.47:1
	16	3,000	16¾	1,500/3,000	4.69	4.13	5.58:1	1.40:1
	16¾	5,000	16¾	1,500/3,000	6.60	6.03	7.85:1	1.59:1
	20	2,000	21¼	1,500/3,000	5.07	4.46	5.58:1	.78:1
	20	3,000	21¼	1,500/3,000	5.07	4.46	5.58:1	.78:1
LWP Type	6	3,000	7 1/16	1,500/3,000	.55	.51	4:1	1.81:1
	8	3,000	9	1,500/3,000	.77	.68	4:1	2.5:1
LWS POSI-LOCK	7 1/16	15,000	7 1/16	1,500/3,000	7.24	6.60	10.85:1	19.44:1
	10	5,000	11	1,500/3,000	4.75	4.18	8.16:1	3.07:1
	10	5,000	11	1,500/3,000	9.31	8.48	10.85:1	7.82:1
	11	10,000	11	1,500/3,000	4.20	3.70	8.16:1	2.21:1
	*11	10,000	11	1,500/3,000	8.23	7.50	10.85:1	5.24:1
	12	3,000	13⅝	1,500/3,000	5.34	4.70	8.16:1	2.56:1
	*12	3,000	13⅝	1,500/3,000	10.56	9.62	10.85:1	6.25:1
	13⅝	5,000	13⅝	1,500/3,000	5.30	4.67	8.16:1	2.56:1
	*13⅝	5,000	13⅝	1,500/3,000	10.56	9.62	10.85:1	6.25:1
	*13⅝	10,000	13⅝	1,500/3,000	11.56	10.52	10.85:1	3.47:1
	16¾	3,000	16¾	1,500/3,000	7.25	6.38	8.16:1	2.05:1
	16¾	5,000	16¾	1,500/3,000	7.25	6.38	8.16:1	1.59:1
	*16¾	5,000	16¾	1,500/3,000	13.97	12.71	10:85:1	3.61:1
	*18¾	10,000	18¾	1,500/3,000	15.30	13.21	7.11:1	1.83:1
	20	2,000	21¼	1,500/3,000	7.80	6.86	8.16:1	1.15:1
	*20	2,000	21¼	1,500/3,000	16.88	15.35	10.85:1	2.52:1
	20	3,000	21¼	1,500/3,000	7.80	6.86	8.16:1	1.15:1
	*20	3,000	21¼	1,500/3,000	16.88	15.35	10.85:1	2.52:1
	*21¼	7,500	21¼	1,500/3,000	16.05	13.86	7.11:1	1.63:1
	*21¼	10,000	21¼	1,500/3,000	16.05	13.86	7.11:1	1.63:1
Types B & E	6	3,000	7 1/16	1,500/3,000	2.75	2.3	6:1	2.57:1
	6	5,000	7 1/16	1,500/3,000	2.75	2.3	6:1	2.57:1
	8	3,000	9	1,500/3,000	2.75	2.3	6:1	1.89:1
	8	5,000	9	1,500/3,000	2.75	2.3	6:1	1.89:1
	10	3,000	11	1,500/3,000	3.25	2.7	6:1	1:51:1
	10	5,000	11	1,500/3,000	3.25	2.7	6:1	1.35:1
	12	3,000	13⅝	1,500/3,000	3.55	2.9	6:1	1.14:1
	14	5,000	13⅝	1,500/3,000	3.55	2.9	6:1	1.14:1
	16	2,000	15½	1,500/3,000	3.65	3.0	6:1	1.05:1

* Shear Ram

APPENDIX B

TABLE B.1. General Operating Specifications For Annular Preventers

MODEL OR TYPE	B.O.P. SIZE Inches	WORKING PRESSURE Max. PSI	VERT. BORE Inches	HYDRAULIC CONTROL Max. PSI	GALS. TO CLOSE	GALS. TO OPEN	PACKOFF OPEN HOLE Min. PSI
CAMERON IRON WORKS, Houston, Texas							
A	6	5,000	7 1/16	1,500	2.2	1.9	N.A.
A	6	10,000	7 1/16	1,500	4.0*	3.1*	N.A.
A	6	15,000	7 1/16	N.A.	N.A.	N.A.	N.A.
A	11	5,000	11	1,500	7.8	6.5	N.A.
A	11	10,000	11	1,500	12.1	10.5	N.A.
A	11	15,000	11	N.A.	N.A.	N.A.	N.A.
A	13⅝	5,000	13⅝	1,500	15.5	13.9	N.A.
A	13⅝	10,000	13⅝	1,500	21.5	18.7	N.A.
A	16¾	5,000	16¾	1,500	33.0	29.0	N.A.
HYDRIL COMPANY, Los Angeles, Calif.							
GK	6	3,000	7 1/16	1,500	2.42	1.90	1,000
GK	6	5,000	7 1/16	1,500	3.28	2.81	1,000
GK	8	3,000	8 13/16	1,500	3.68	2.90	1,050
GK	8	5,000	8 13/16	1,500	5.81	4.93	1,150
GK	10	3,000	11	1,500	6.32	4.71	1,150
GK	10	5,000	11	1,500	8.34	6.78	1,150
GK	12	3,000	13⅝	1,500	9.66	7.60	1,150
GK	13⅝	5,000	13⅝	1,500	15.28	12.04	1,150
GK	16	2,000	16¾	1,500	14.81	10.65	1,150
GK	16	3,000	16¾	1,500	17.87	13.43	1,150
GK	16¾	5,000	16¾	1,500	24.40	16.94	1,150
GK	18	2,000	17⅞	1,500	17.93	12.28	1,110
GK	7 1/16	10,000	7 1/16	1,500	8.01	6.02	1,150
GK	9	10,000	9	1,500	13.52	10.17	1,150
GK	11	10,000	11	1,500	21.34	16.04	1,150
GK	13⅝	10,000	13⅝	1,500	29.35	20.96	1,150
GL	13⅝	5,000	13⅝	1,500	16.80	16.80	1,300
GL	16¾	5,000	16¾	1,500	28.73	28.73	1,300
GL	18¾	5,000	18¾	1,500	37.4	37.4	1,300
GL	21¼	5,000	21¼	1,500	48.58	48.58	1,300
MSP	6	2,000	7 1/16	1,500	2.42	1.68	1,000
MSP	8	2,000	8 13/16	1,500	3.89	2.51	1,050
MSP	10	2,000	11	1,500	6.32	4.45	1,150
MSP	20	2,000	20¾*	1,500	26.39	16.09	1,100
MSP	20	2,000	21¼	1,500	26.39	16.09	1,100
MSP	29½	500	29½	1,500	60.0**	0	1,500

*Obsolete API Standard.
**Full Stroke, Self Opening.

Note: Adapted from *Quick Reference Tables,* Oilfield Division, Stewart & Stevenson, Inc. Figures shown are 1974–75 data reflecting information received from manufacturers.

MODEL OR TYPE	B.O.P. SIZE Inches	WORKING PRESSURE Max. PSI	VERT. BORE Inches	HYDRAULIC CONTROL Max. PSI	GALS. TO CLOSE	GALS. TO OPEN	PACKOFF OPEN HOLE Min. PSI
REGAN FORGE & ENGINEERING CO., San Pedro, Calif.							
K	3	3,000	3	3,000	.2	NOT APPLICABLE	VARIABLE
K	4	3,000	4	3,000	.8		
K	7	3,000	6¼	3,000	1.6		
K	8⅝	3,000	7⅞	3,000	3.4		
K	9⅝	3,000	8⅞	3,000	5.7		
K	10¾	3,000	10	3,000	7.6		
K	11¾ (Old)	3,000	10⅞	3,000	8.1		
K	11¾ (New)	3,000	11⅛	3,000	10.3		
K	13⅜	3,000	12⅜	3,000	15.3		
K	13¾	3,000	13¾	3,000	19.9		
K	16	3,000		3,000	22.5		
K	18⅝	3,000		3,000	29.5		
KFD	16	300	8	1,000	1.75		
KFD	18⅝	300	8	1,000	2.5		
KFD	20	300	8	1,000	2.5		
KFD	22	300	8	1,000	3.0		
KFD	24	300	8	1,000	3.0		
KFL	13⅝	3,000	13⅝	Well +500	19½		
KFL	13⅝	5,000	13⅝	Well +500	22		
KFL	13⅝	10,000	13⅝	Well +500	24½		
KFL	16¾	3,000	16¾	Well +500	25¾		
KFL	16¾	5,000	16¾	Well +500	29		
KFL	16¾	10.000	16¾	Well +500	31½		
KFL	20	2,000	20¾	Well +500	28½		
KFL	20	3,000	20¾	Well +500	32		
KFL	20	5,000	20¾	Well +500	35		
KFL	30	1,000	28	Well +500	47½		
KFL	30	2,000	28	Well +500	52		
KFL	30	1,000	26½	Well +500	51½		
KFL	30	2,000	26½	Well +500	56		
Torus	6	3,000*	7 1/16	3,000	4.3		
Torus	6	6,000*	7 1/16	3,000	4.3		
Torus	8	3,000*	9	3,000	8.1		
Torus	8	6,000*	9	3,000	8.1		
RUCKER-SHAFFER, Houston, Texas							
Spherical	6	3,000	7 1/16	1,500	4.57	3.21	VARIABLE
B.O.P.	6	5,000	7 1/16	1,500	4.57	3.21	
	8	3,000	9	1,500	7.23	5.03	
	8	5,000	9	1,500	11.05	8.72	
	10	3,000	11	1,500	11.00	6.78	
	10	5,000	11	1,500	18.67	14.59	
	12	3,000	13⅝	1,500	23.50	14.67	
	13⅝	5,000	13⅝	1,500	23.58	17.41	
	13⅝	10,000	13⅝	1,500	51.24	42.68	
	16¾	5,000	16¾	1,500	33.26	25.61	
	18¾	5,000	18¾	1,500	48.16	37.61	
	20	2,000	21¼	1,500	32.59	16.92	
	21¼	5,000	21¼	1,500	61.37	47.76	

APPENDIX B

TABLE B.2. APPROXIMATE VOLUME OF FLUID (U.S. GALLONS) REQUIRED TO CLOSE ANNULAR PREVENTERS ON VARIOUS–SIZED TUBULAR GOODS.

Note: All fluid volumes shown are approximated average values to be used for estimating purposes only. This table assumes that: (1) the fluid volumes required for full closure are correct as shown in Table B.1; (2) the preventer and the packing unit are in new condition; (3) there is no hole pressure; and (4) the regulator valve is set at the recommended closing pressure. The asterisk (*) indicates the recommended pipe size upon which a particular preventer should be closed.

	HYDRIL																									
	GK																MSP					GL				
PIPE SIZE (OD)	6" 3M	6" 5M	8" 3M	8" 5M	10" 3M	10" 5M	12" 3M	13⅝" 5M	16" 2M	16" 3M	16¾" 5M	18" 2M	7¹⁄₁₆" 10M	9" 10M	11" 10M	13⅝" 10M	6" 2M	8" 2M	10" 2M	20" 2M	29½" 500	13⅝" 5M	16¾" 5M	18¾" 5M	21¼" 5M
5½"	–	–	2.3	3.6	4.7	6.3	8.1	12.8	13.2	15.9	21.8	16.2	–	8.5	16.0	24.6	–	–	4.7	24.6	57.9	14.1	25.6	34.2	45.3
5"	1.2	1.6	2.5	4.0	5.0	6.6	8.4	13.2	13.5	16.3	22.2	16.5	4.0	9.3	16.9	25.4	1.2	2.7	5.0	24.9	58.3	14.5	26.2	34.7	45.9
4½"	1.4	2.0	2.7	4.3	5.3	6.9	8.6 *	13.6 *	13.7 *	16.6 *	22.6 *	16.8 *	4.8	10.1	17.8	26.1 *	1.4	2.9	5.3	25.2 *	58.6	15.0 *	26.7 *	35.3 *	46.4 *
3½"	1.8	2.5	3.1 *	4.9 *	5.7 *	7.5 *	9.0	14.3	14.2	17.1	23.3	17.2	6.0	11.5 *	19.2 *	27.4	1.8	3.3	5.7 *	25.7	59.2	15.7	27.5	36.1	47.3
2⅞"	2.0 *	2.7 *	3.3	5.2	5.9	7.8	9.2	14.6	14.4	17.3	23.7	17.5	6.7 *	12.1	19.9	28.0	2.0 *	3.5 *	5.9	25.9	59.4	16.0	27.9	36.5	47.7
2⅜"	2.1	2.9	3.4	5.4	6.0	7.9	9.4	14.8	14.5	17.5	23.9	17.6	7.1	12.6	20.3	28.5	2.1	3.6	6.0	26.1	59.6	16.3	28.2	36.8	48.0
1.90"	2.2	3.0	3.6	5.5	6.1	8.1	9.5	15.0	14.6	17.6	24.1	17.7	7.4	12.9	20.7	28.8	2.2	3.7	6.1	26.2	59.8	16.5	28.4	37.0	48.2
1.66"	2.3	3.1	3.8	5.6	6.2	8.2	9.5	15.1	14.7	17.7	24.2	17.8	7.6	13.1	20.9	28.9	2.3	3.8	6.2	26.2	59.8	16.6	28.5	37.1	48.3

	CAMERON "A"								
	6" 5M	6" 10M	6" 15M	11" 5M	11" 10M	11" 15M	13⅝" 5M	13⅝" 10M	16¾" 5M
5½"	–	–	N.A.	5.9	9.1	N.A.	13.0	18.0	29.4
5"	1.1	2.0	–	6.2	9.6	–	13.4	18.6	30.1
4½"	1.3	2.4	–	6.5	10.1	–	13.8 *	19.2 *	30.6 *
3½"	1.7	3.0	–	7.0 *	10.9 *	–	14.5	20.1	31.6
2⅞"	1.8 *	3.3 *	–	7.3	11.3	–	14.8	20.5	32.0
2⅜"	2.0	3.6	–	7.4	11.5	–	15.0	20.8	32.3
1.90"	2.0	3.7	–	7.6	11.7	–	15.2	21.1	32.6
1.66"	2 1	3.8	–	7.6	11.8	–	15.3	21.2	32.7

	RUCKER–SHAFFER "SPHERICAL"												
	6" 3M	6" 5M	8" 3M	8" 5M	10" 3M	10" 5M	12" 3M	13⅝" 5M	13⅝ 10M	16¾" 5M	18¾" 5M	20" 2M	21¼" 5M
5½"	–	–	4.5	6.9	8.3	14.0	19.7	19.7	42.9	29.7	44.0	30.4	57.3
5"	2.3	2.3	5.0	7.6	8.7	14.8	20.3	20.4	44.3	30.3	44.7	30.8	58.0
4½"	2.7	2.7	5.4	8.3	9.2	15.6	20.9 *	21.0 *	45.7 *	30.9 *	45.4 *	31.1 *	58.6 *
3½"	3.6	3.6	6.1 *	9.4 *	9.9 *	16.8 *	21.9	22.0	47.9	31.8	46.5	31.7	59.7
2⅞"	3.8 *	3.8 *	6.5	9.9	10.3	17.4	22.5	22.5	49.0	32.3	47.0	32.0	60.2
2⅜"	4.1	4.1	6.7	10.3	10.5	17.8	22.8	22.9	49.7	32.6	47.4	32.2	60.6
1.90"	4.2	4.2	6.9	10.6	10.7	18.1	23.0	23.1	50.2	32.8	47.7	32.3	60.9
1.66"	4.3	4.3	7.0	10.7	10.7	18.2	23.2	23.2	50.5	32.9	47.8	32.4	61.0

General Operating Specifications For Hydraulic Control Valves

TYPE OR MODEL	LINE SIZE Inches	WORKING PRESSURE Max.PSI	BORE SIZE Inches	HYDRAULIC OPERATION Max. PSI	GALS. TO OPEN	GALS. TO CLOSE
CAMERON IRON WORKS, Houston, Texas						
HCR	4	3,000	4	1,500	0.61	0.52
HCR	4	5,000	4	1,500	0.61	0.52
HCR	6	3,000	7	1,500	2.25	1.95
HCR	6	5,000	7	1,500	2.25	1.95
F	2	960-3,000	1 13/16	1,500/5,000	.10	.10
F	2	5,000-15,000	1 13/16	1,500/5,000	.16	.16
F	2	960-3,000	2 1/16	1,500/5,000	.10	.10
F	2	5,000-15,000	2 1/16	1,500/5,000	.16	.16
F	2 1/2	960-10,000	2 9/16	1,500/5,000	.20	.20
F	2 1/2	15,000	2 9/16	1,500/5,000	.40	.40
F	3	960-2,000	3 1/8	1,500/5,000	.15	.15
F	3	3,000-5,000	3 1/8	1,500/5,000	.24	.24
F	3	10,000	3 1/8	1,500/5,000	.28	.28
F	3	15,000	3 1/8	1,500/5,000	.49	.49
F	4	2,000-5,000	4 1/8	1,500/5,000	.30	.30
F	4	10,000	4 1/8	1,500/5,000	.59	.59
F	6	2,000-5,000	6 1/8	1,500/5,000	.84	.84
DV	4	3,000	4	1,500	0.8	1.1
DV	4	5,000	4	1,500	0.8	1.1
DV	6	3,000	7	1,500	2.1	3.6
DV	8	3,000	9	1,500	2.4	5.6
DV	10	3,000	11	1,500	5.7	11.4
DV	10	5,000	11	1,500	5.7	11.4
DV	12	3,000	13 5/8	1,500	11.8	22.7
ROCKWELL MANUFACTURING CO., Pittsburgh, Pa.						
AC Valve	2	2,000		2,500	.13	.11
with U-1	2	3,000		2,500	.13	.11
Hyd.	2	5,000		2,500	.13	.11
Opr.	2	10,000		2,500	.21	.20
	2 1/2	2,000		2,500	.26	.23
	2 1/2	3,000		2,500	.26	.23
	2 1/2	5,000		2,500	.26	.23
	2 1/2	10,000		2,500	.45	.42
	3	2,000		2,500	.30	.25
	3	3,000		2,500	.51	.46
	3	5,000		2,500	.51	.46
	4	2,000		2,500	.69	.62
	4	3,000		2,500	.69	.62
	4	5,000		2,500	1.04	.98

Note: Adapted from *Quick Reference Tables,* Oilfield Division, Stewart & Stevenson, Inc. Figures shown are 1974–75 data reflecting information received from manufacturers.

TYPE OR MODEL	LINE SIZE Inches	WORKING PRESSURE Max. PSI	BORE SIZE Inches	HYDRAULIC OPERATION Max. PSI	GALS. TO OPEN	GALS. TO CLOSE
RUCKER-SHAFFER, Houston, Texas						
Flo-Seal	2 Reg.	2,000	1 11/16	3,000	.2	.2
	2	2,000	2 1/16	3,000	.2	.2
	2 Reg.	3,000	1 11/16	3,000	.2	.2
	2	3,000	2 1/16	3,000	.2	.2
	2 Reg.	5,000	1 11/16	3,000	.2	.2
	2	5,000	2 1/16	3,000	.2	.2
	2 1/16	10,000	2 1/16	3,000	.4	.4
	2 1/16	15,000	2 1/16	3,000	.4	.4
	2 1/2	2,000	2 9/16	3,000	.3	.3
	2 1/2	3,000	2 9/16	3,000	.3	.3
	2 1/2	5,000	2 9/16	3,000	.3	.3
	3	2,000	3 1/8	3,000	.3	.3
	3	3,000	3 1/8	3,000	.3	.3
	3	5,000	3 1/8	3,000	.3	.3
	3 1/16	10,000	3 1/16	3,000	.6	.6
	4	3,000	4 1/16	3,000	.8	.8
	4	5,000	4 1/16	3,000	.8	.8
	4 1/16	10,000	4 1/16	3,000	1.3	1.3
	6	3,000	7 1/16	3,000		
Flo-Seal	2 Reg.	2,000	1 11/16	3,000	.3	.3
with	2	2,000	2 1/16	3,000	.3	.3
Ramlock	2 Reg.	3,000	1 11/16	3,000	.3	.3
	2	3,000	2 1/16	3,000	.3	.3
	2 Reg.	5,000	1 11/16	3,000	.3	.3
	2	5,000	2 1/16	3,000	.3	.3
	2 1/16	10,000	2 1/16	3,000	.4	.4
	2 1/16	15,000	2 1/16	3,000	.4	.4
	2 1/2	2,000	2 9/16	3,000	.3	.3
	2 1/2	3,000	2 9/16	3,000	.3	.3
	2 1/2	5,000	2 9/16	3,000	.3	.3
	3	2,000	3 1/8	3,000	.4	.4
	3	3,000	3 1/8	3,000	.4	.4
	3	5,000	3 1/8	3,000	.4	.4
	3 1/16	10,000	3 1/16	3,000	.6	.6
	4	3,000	4 1/16	3,000	.8	.8
	4	5,000	4 1/16	3,000	.8	.8
	4 1/16	10,000	4 1/16	3,000	.8	.8
	6	3,000	7 1/16	3,000		
Type DB	3	3,000	3 1/8	3,000	.3	.3
	3	5,000	3 1/8	3,000	.3	.3
	3 1/16	10,000	3 1/16	3,000	.6	.6
	4	3,000	4 1/16	3,000	.8	.8
	4	5,000	4 1/16	3,000	.8	.8
	4 1/16	10,000	4 1/16	3,000	1.3	1.3
	6	3,000	7 1/16	3,000	2.0	2.0

APPENDIX D

CALCULATED INTERNAL YIELD PRESSURE OF CASING

O. D. (Inches)	Lbs. Per Ft. W/Couplings	F-25 psi	H-40 psi	J-55 psi	N-80 psi	P-110 (Tentative) psi
4.0	9.50	2260	3620	4970	7230	9550
4½	9.50	1990	3190	4380		
4½	10.50			4790		
4½	11.60			5350	7780	10690
4½	13.50				9020	12410
4¾	16.00			6760	9640	14420
5	11.50	1930		4240		
5	13.00			4870	7090	
5	15.00			5700	8290	11390
5	18.00			6960	10140	13940
5½	13.00	1810				
5½	14.00		3100	4270		
5½	15.00		3340	4600	6690	
5½	15.50			4800		
5½	17.00		3870	5320	7740	10640
5½	20.00			6320	9190	12640
5½	23.00			7260	10560	14520
6	15.00	1740				
6	18.00		3360	4620	6720	
6	20.00			5200	7560	
6	23.00			6100	8870	12190
6⅝	13.00	1220				
6⅝	17.00	1620				
6⅝	20.00		3040	4180	6080	
6⅝	24.00			5110	7440	10230
6⅝	28.00			6060	8810	12120
6⅝	32.00				10040	13800
7	17.00	1440	2310	2680		
7	20.00		2720	3740	5440	
7	22.00		3010	4140	6020	
7	23.00			4360	6340	
7	24.00		3320	4570	6640	
7	26.00		3620	4980	7240	9960
7	28.00			5380	7030	
7	29.00				8160	11220
7	30.00			5820	8460	
7	32.00			6240	9060	12460
7	35.00				9960	13690
7	38.00				10800	14850
7⅝	20.00	1430				
7⅝	24.00		2750			
7⅝	26.40			4140	6020	
7⅝	29.70*			4730	6890	9470
7⅝	33.70			5430	7890	10860
7⅝	39.00				9180	12630
8⅝	24.00	1340		2950		
8⅝	28.00		2470	3390	4930	
8⅝	32.00		2860	3930	5710	
8⅝	36.00			4460	6490	
8⅝	38.00			4740	6890	
8⅝	40.00				7300	10040
8⅝	44.00			5580	8120	11160
8⅝	49.00				9040	12430
9	40.00			4540	6610	
9⅝	29.30	1280				
9⅝	32.30		2270			
9⅝	36.00		2560	3250	5120	
9⅝	40.00			3950	5750	
9⅝	43.50			4360	6300	8700
9⅝	47.00			4720	6870	9440
9⅝	53.50			5450	7930	10900
10¾	32.75	1140	1820	2490		
10½	40.50		2280	3130	4560	
10¾	45.50			3580	5120	
10¾	51.00			4030	5860	7690
10¾	55.50			4430	6450	8460
11¾	38.00	1120				
11¾	42.00		1980			
11¾	47.00			3070	4460	
11¾	54.00			3560	5180	

Adapted from the *Engineers' Handbook,* Dowell, division of The Dow Chemical Company.

(continued)

O. D. (Inches)	Lbs. Per Ft. W/Couplings	F-25 psi	H-40 psi	J-55 psi	N-80 psi	P-110 (Tentative) psi
11¾	60.00			4010	5830	
13⅜	48.00	1080	1730	2360	3460	
13⅜	54.50			2730	3970	
13⅜	61.00			3090	4500	
13⅜	68.00			3450	5020	
13⅜	72.00			3700	5380	
16	55.00	850				
16	65.00		1640			
16	75.00			2630		
16	84.00			2980		
20	90.00	910	1530			
20	94.00	960	1530			

Values shown include safety factor based on minimum yield strength.

A P I — INTERNAL YIELD PRESSURE OF DRILL PIPE

Size O. D. Inches	Wt./ft. With Joints	Grade D	Grade E	Grade G*
2⅜	4.85		10,500	14,700
2⅜	6.65	11,350	15,470	21,660
2⅞	6.85		9,900	13,870
2⅞	10.40	12,120	16,530	23,140
3½	9.50		9,530	13,340
3½	13.30	10,120	13,800	19,320
3½	15.50	12,350	16,840	23,570
4	11.85		8,590	12,040
4	14.00	7,940	10,830	15,160
4½	13.75		7,900	11,070
4½	16.60	7,210	9,830	13,760
4½	18.10	7,980	10,880	15,230
4½	20.00	9,200	12,540	17,560
5	15.00		7,700	10,880
5	19.50	6,960	9,500	13,300
5½	21.90	6,320	8,620	12,060
5½	24.70	7,260	9,900	13,860
6⅝	25.20	4,800	6,540	9,150

*Non A.P.I. Grade
Values shown include safety factor based on minimum yield strength.

CALCULATED INTERNAL YIELD PRESSURE OF TUBING— A P I TUBING

Size I.D. In.	Size O.D. In.	Lbs. Per Foot With Couplings	Lapweld psi	F25 psi	H40 psi	J55 psi	N80 psi	P105 psi
¾	1.050	1.20		4300	6890	9470	13780	18140
1	1.315	1.80		4050	6470	8900	12950	17000
1¼	1.660	2.30	4420	3690	5910	8120	11800	14100
1¼	1.660	2.40	4420	3690	5910	8120	11800	14100
1½	1.900	2.75	4000	3050	4880	6720	9770	12800
1½	1.900	2.90	4000	3050	4880	6720	9770	12800
1¾	2.062	3.40			5290	6650	9600	12700
2	2.375	4.60	4200	3200	5600	7040	10200	13400
2	2.375	4.70	4200	3200	5600	7040	10200	13400
2	2.375	5.95				9400	13700	18000
2	2.375	6.20				9700	14100	18500
2	2.375	7.70				12500	18100	23800
2½	2.875	6.40	3960	3020	4830	6640	9660	12600
2½	2.875	6.50	3960	3020	4830	6640	9660	12600
2½	2.875	7.90				8500	12200	16050
2½	2.875	8.70				9400	13700	18000
2½	2.875	8.90				9700	14100	18500
2½	2.875	9.50				10400	15100	19900
2½	2.875	11.00				12400	18000	23600
3	3.500	7.70		2470	3950	5430	7900	
3	3.500	9.20	3800	2900	4640	6390	9290	12190
3	3.500	10.20	4330	3300	5280	7270	10570	13900
3	3.500	9.30	3800	2900	4640	6390	9290	12190
3	3.500	12.95					15000	19690
3½	4.000	9.50	2960	2260	3620	4970	7230	9550
3½	4.000	11.00	3430	2620	4190	5760	8380	11100
4	4.500	12.60	3160	2410	3850	5300	7710	10100
4	4.500	12.75	3160	2410	3850	5300	7710	10100

Values shown include safety factor based on minimum yield strength.

APPENDIX E

FORMATION FRACTURING [8,15,16]

1. To calculate the pressure gradient that, if exceeded, would be expected to fracture the formation, use the following formula:

$$\frac{P}{Z} = \frac{\frac{Sz}{Z} + \frac{2p}{Z}}{3}$$

where P = injection pressure
where p = pore pressure

where Sz = overburden pressure
where Z = depth

Equation (1)

2. To calculate the above pressure gradient in the event the pressure is applied through perforated casing, use:

$$\frac{P}{Z} = \frac{\frac{Sz}{Z} + \frac{2p}{Z}}{2}$$

Equation (2)

3. Areal tectonic conditions can affect the fracture gradient derived from equations (1) or (2) above.

   a. The observed gradient will be less than or equal to the calculated value in tectonically relaxed areas.

   b. The observed gradient will be greater than or equal to the calculated value in tectonically active areas.

4. The orientation of fractures resulting from excessive injection pressures is expected to be:

   a. Vertical in tectonically relaxed areas.

   b. Horizontal in tectonically active areas.

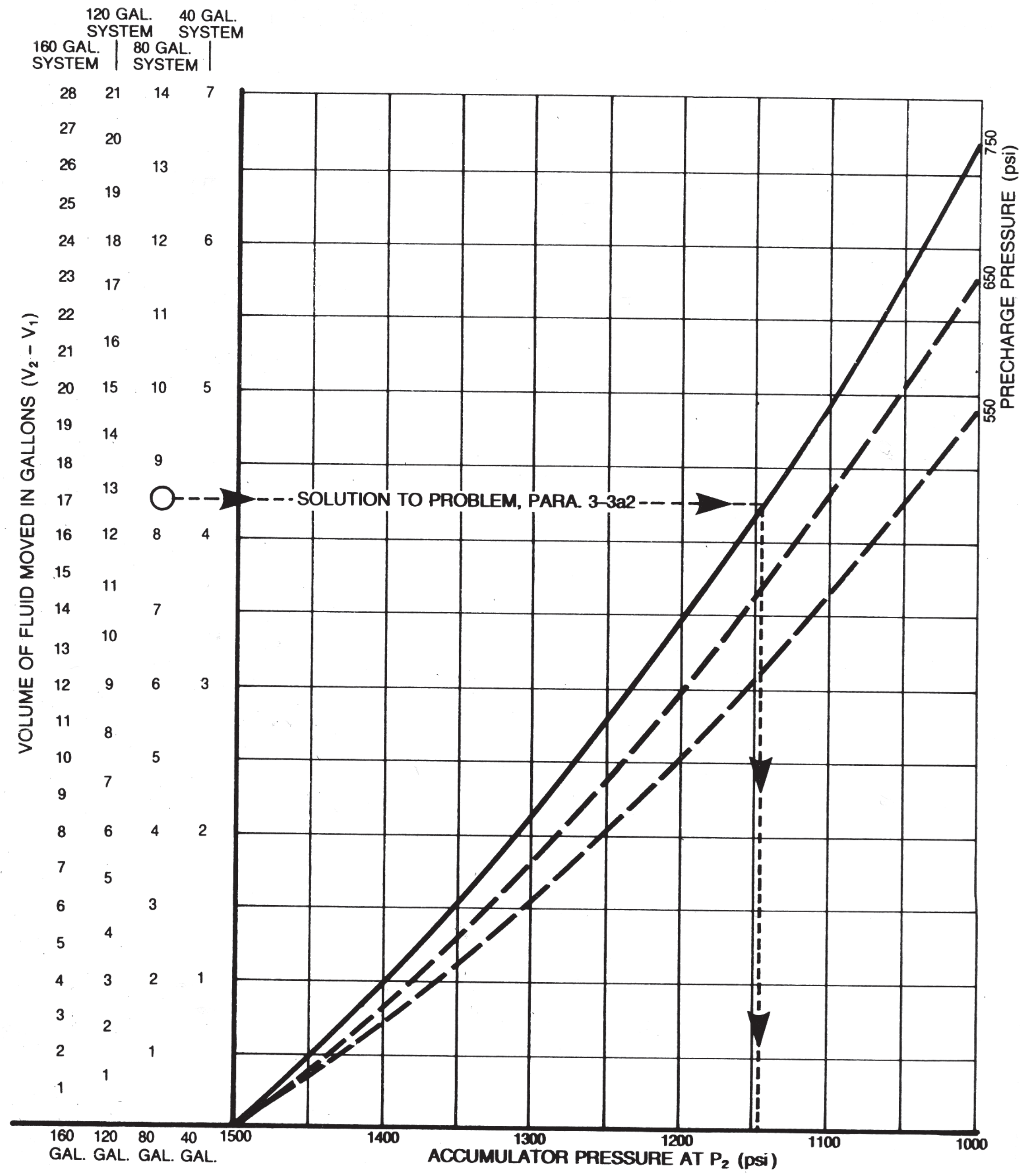
[8,15,16] Superior figures refer to list of references at the end of this publication.

APPENDIX F

FLUID MOVED vs. ACCUMULATOR PRESSURE FOR SYSTEMS OF VARIOUS CAPACITIES

(THE EFFECT OF REDUCED PRECHARGE IS ALSO SHOWN)

FIGURE F.1. ACCUMULATOR SYSTEMS WITH: 1500 psi WORKING PRESSURE (P_1)
750 psi NOMINAL PRECHARGE

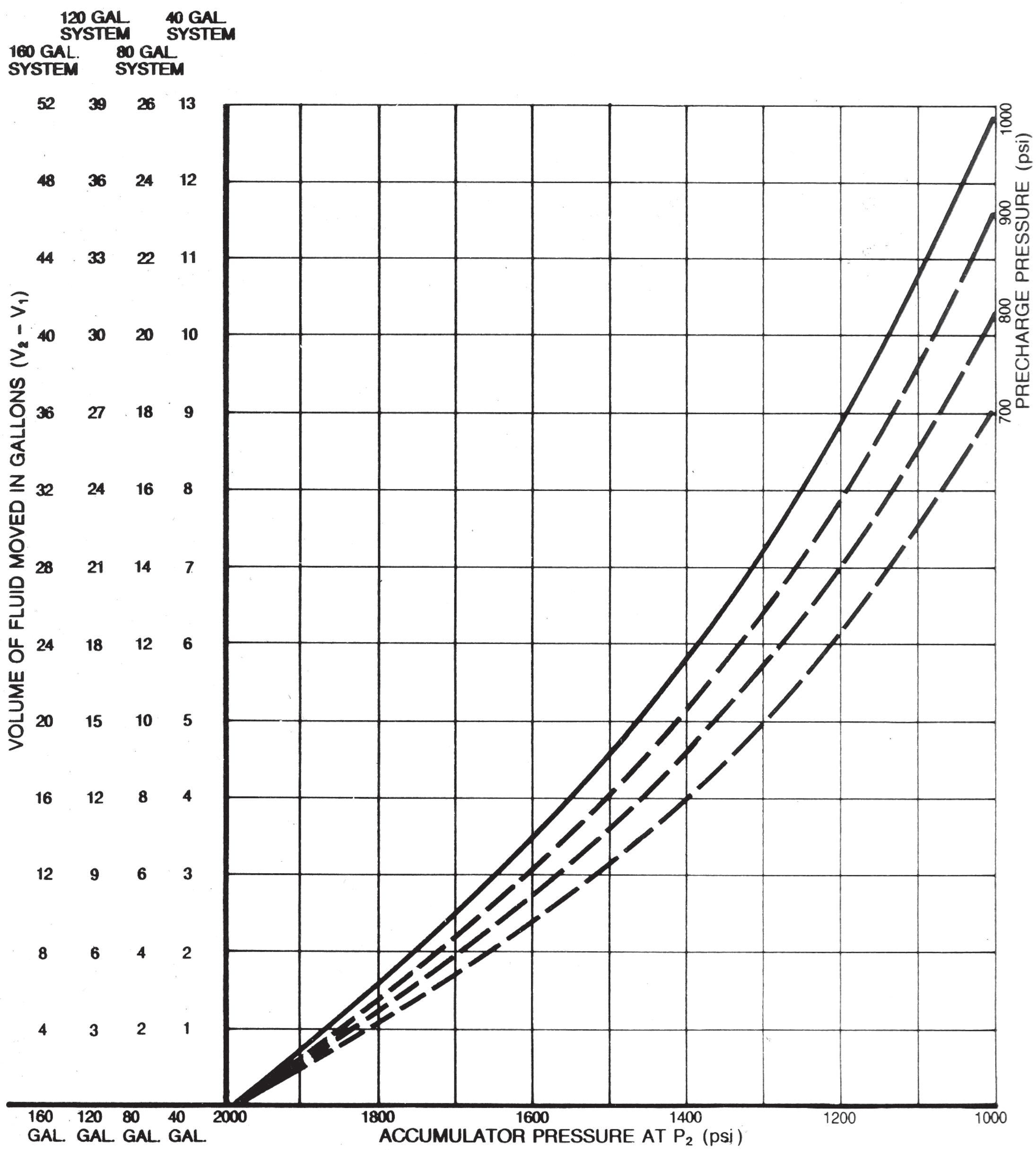


APPENDIX F

FLUID MOVED vs. ACCUMULATOR PRESSURE FOR SYSTEMS OF VARIOUS CAPACITIES

(THE EFFECT OF REDUCED PRECHARGE IS ALSO SHOWN)

FIGURE F.2. ACCUMULATOR SYSTEMS WITH: 2000 psi WORKING PRESSURE (P_1) 1000 psi NOMINAL PRECHARGE

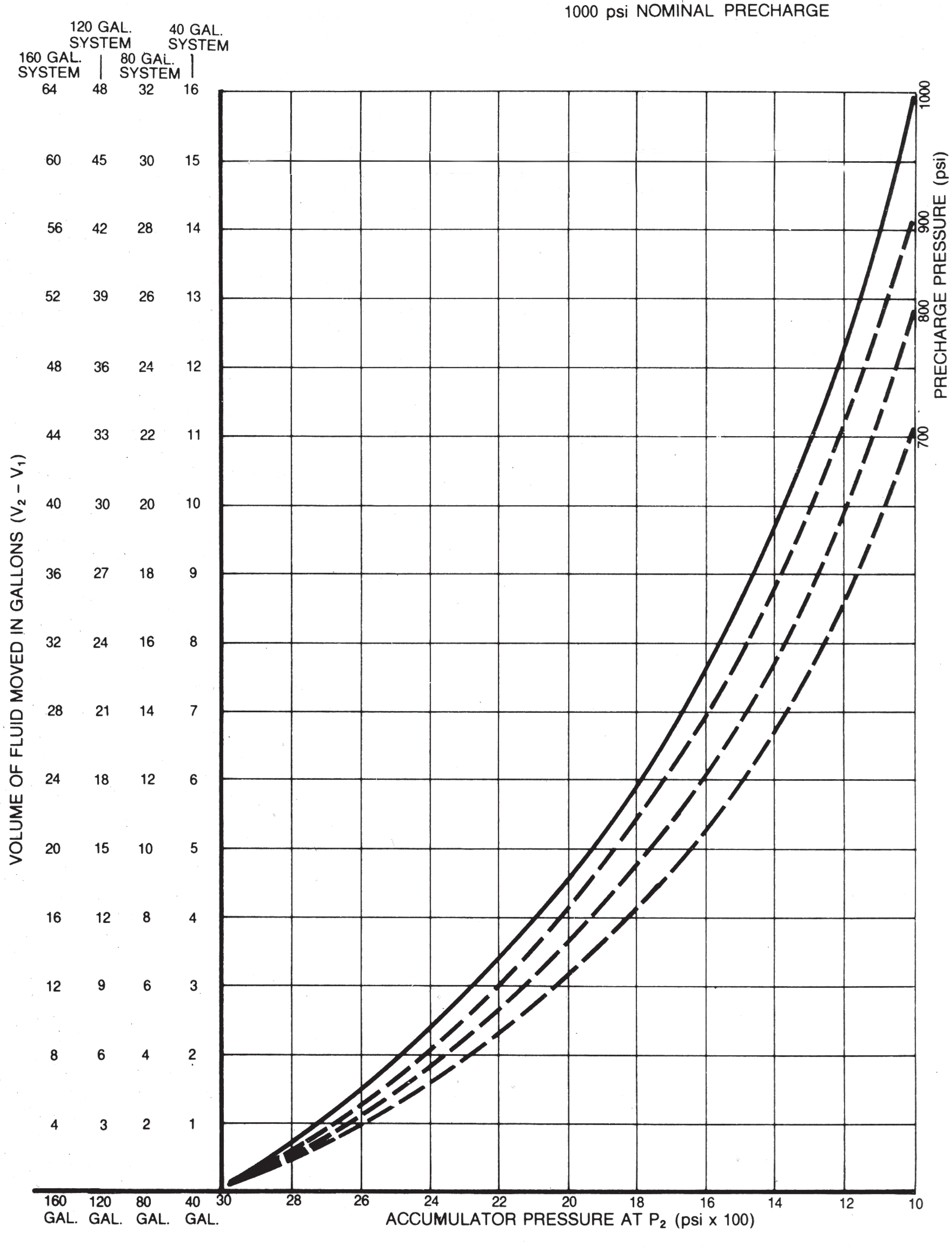


APPENDIX F

FLUID MOVED vs. ACCUMULATOR PRESSURE FOR SYSTEMS OF VARIOUS CAPACITIES

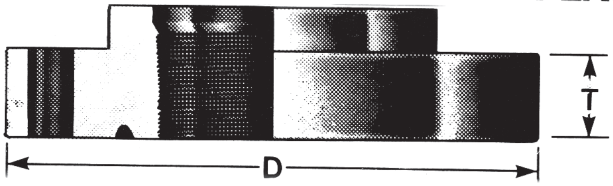
(THE EFFECT OF REDUCED PRECHARGE IS ALSO SHOWN)

FIGURE F.3. ACCUMULATOR SYSTEMS WITH: 3000 psi WORKING PRESSURE (P_1)
1000 psi NOMINAL PRECHARGE



APPENDIX G

API FLANGE DATA



API TYPE 6B — FLANGE SPECIFICATIONS

Working Pressure (psi) Standard Studs (1)	Working Pressure (psi) Reduced Hardness Studs	Nominal Size (in.)	D Outside Diameter (in.)	T Total Flange Thickness (in.)	Hub Diameter (in.)	Bolt Circle Diameter (in.)	Pitch Dia. Ring Groove (in.)	R or RX Ring Number	Studs Number Required	Studs Diameter (in.)	Studs Length (in.) All Thread	Studs Length (in.) Tap End
2000		2	6½	1 5/16	3 5/16	5	3¼	23	8	⅝	4½	3½
		2½	7½	1 7/16	3 15/16	5½	4	26	8	¾	5¼	4
		3	8¼	1 9/16	4⅝	6⅝	4⅞	31	8	¾	5¼	4
		4	10¾	1 13/16	6	8½	5⅞	37	8	⅞	6	4½
		6	14	2 3/16	8¾	11½	8 5/16	45	12	1	7	5
		8	16½	2½	10¾	13¾	10⅝	49	12	1⅛	8¼	5¾
		10	20	2 13/16	13½	17	12¾	53	16	1¼	8¾	6¼
		12	22	2 15/16	15¾	19¼	15	57	20	1¼	9¼	6¼
		16	27	3 5/16	19½	23¾	18½	65	20	1½	10¼	7¼
		18	29¼	3 9/16	21½	25¾	21	69	20	1⅝	11	8¼
		20	32	3⅞	24	28½	23	73	24	1⅝	11¾	8¼
3000		2	8½	1 13/16	4⅛	6½	3¾	24	8	⅞	6	4½
		2½	9⅝	1 15/16	4⅞	7½	4¼	27	8	1	6½	5
		3	9½	1 13/16	5	7½	4⅞	31	8	⅞	6	4½
		4	11½	2 1/16	6¼	9¼	5⅞	37	8	1⅛	7	5¼
		6	15	2½	9¼	12½	8 5/16	45	12	1⅛	8¼	5¾
		8	18½	2 13/16	11¾	15½	10⅝	49	12	1⅜	9	6½
		10	21½	3 1/16	14½	18½	12¾	53	16	1⅜	9½	6¾
		12	24	3 7/16	16½	21	15	57	20	1⅜	10¾	7¼
		16	27¾	3 15/16	20	24¼	18½	66	20	1⅝	11¾	8¼
		18	31	4½	22¼	27	21	70	20	1⅞	13¾	9½
		20	33¾	4¾	24½	29½	23	74	20	2	14½	10¼
5000		2	8½	1 13/16	4⅛	6½	3¾	24	8	⅞	6	4½
		2½	9⅝	1 15/16	4⅞	7½	4¼	27	8	1	6½	5
		3	10½	2 3/16	5¼	8	5⅜	35	8	1⅛	7½	5½
		4	12¼	2 7/16	6⅜	9½	6⅜	39	8	1¼	8	6
		6	15½	3⅝	9	12½	8 5/16	46	12	1⅜	10¾	7½
		8	19	4 1/16	11½	15½	10⅝	50	12	1⅝	12	8½
		10	23	4 11/16	14½	19	12¾	54	12	1⅞	13¾	9½

API TYPE 6BX — FLANGE SPECIFICATIONS

Working Pressure (psi) Standard Studs (1)	Working Pressure (psi) Reduced Hardness Studs	Size and Bore (in.)	D Outside Diameter (in.)	T Flange Thickness (in.)	Hub Diameter (in.)	Bolt Circle Diameter (in.)	Outside Dia. Ring Groove (in.)	BX Ring Number	Studs Number Required	Studs Diameter (in.)	Studs Length (in.) All Thread	Studs Length (in.) Tap End
5000	3,800	13⅝	26½	4 7/16	18 15/16	23¼	16.063	BX-160	16	1⅝	12½	8½
	3,800	16¾	30⅜	5⅛	21⅞	26⅝	18.832	BX-162	16	1⅞	14½	9½
	3,800	16¾ (2)	30¼	5 3/64	22¼	26¾	19.604	BX-161	16	1¾	14¼	9½
	3,800	18¾	35⅝	6 17/32	26 9/16	31⅝	22.185	BX-163	20	2	17¼	11½
	3,800	21¼	39	7⅛	29⅞	34⅞	24.904	BX-165	24	2	18½	12
10000	10,000	1 13/16	7⅜	1 21/32	3½	5¾	3.062	BX-151	8	¾	5¼	3¾
	10,000	2 1/16	7⅞	1 47/64	3 15/16	6¼	3.395	BX-152	8	¾	5¼	3¾
	10,000	2 9/16	9⅛	2 1/64	4¾	7¼	4.046	BX-153	8	⅞	6	4½
	10,000	3 1/16	10⅝	2 19/64	5 19/32	8½	4.685	BX-154	8	1	7	4¾
	7,600	4 1/16	12 7/16	2 49/64	7 3/16	10 3/16	5.930	BX-155	8	1⅛	8¼	5½
	7,600	7 1/16	18⅞	4 1/16	11⅞	15⅞	9.521	BX-156	12	1½	11¼	7¾
	7,600	9	21¾	4⅞	14¾	18¾	11.774	BX-157	16	1½	13	8½
	7,600	11	25¾	5 9/16	17¾	22¼	14.064	BX-158	16	1¾	15	9½
	7,600	13⅝	30¼	6⅝	21¾	26½	17.033	BX-159	20	1⅞	17½	11¼
	7,600	16¾	34 5/16	6⅝	25 13/16	30 9/16	18.832	BX-162	24	1⅞	17½	10¾
	7,600	18¾	40 15/16	8 25/32	29⅝	36 7/16	22.752	BX-164	24	2¼	22¼	14¼
	7,600	21¼	45	9½	33⅜	40¼	25.507	BX-166	24	2½	24¼	15½
15000	15,000	1 13/16	8 3/16	1 25/32	3 27/32	6 5/16	3.062	BX-151	8	⅞	5½	4
	11,400	2 1/16	8¾	2	4⅜	6⅞	3.395	BX-152	8	⅞	6	4¼
	11,400	2 9/16	10	2¼	5 1/16	7⅞	4.046	BX-153	8	1	7	4¾
	11,400	3 1/16	11 5/16	2 17/32	6 1/16	9 1/16	4.685	BX-154	8	1⅛	7½	5¼
	11,400	4 1/16	14 3/16	3 3/32	7 11/16	11 7/16	5.930	BX-155	8	1⅜	9½	6½
	11,400	7 1/16	19⅞	4 11/16	12 13/16	16⅞	9.521	BX-156	16	1½	12¾	8¼
	11,400	9	25½	5¾	17	21¾	11.774	BX-157	16	1⅞	15¾	10¼
	11,400	11	32	7⅜	23	28	14.064	BX-158	20	2	19¼	12
20000	20,000	1 15/16	10⅛	2½	5¼	8	3.062	BX-151	8	1	7¾	5
	20,000	2 1/16	11 5/16	2 13/16	6 1/16	9 1/16	3.395	BX-152	8	1⅛	8¼	5½
	20,000	2 9/16	12 13/16	3⅛	6 13/16	10 5/16	4.046	BX-153	8	1¼	9¼	6
	20,000	3 1/16	14 1/16	3⅜	7 9/16	11 5/16	4.685	BX-154	8	1⅜	10¼	6¾
	20,000	4 1/16	17 9/16	4 3/16	9 3/16	14 1/16	5.930	BX-155	8	1¾	12¼	8¼
	20,000	7 1/16	25 13/16	6½	15 3/16	21 13/16	9.521	BX-156	16	2	17½	11¼

(1) Standard studs are A193 Gr B7. Working pressure is not reduced for A320 Gr L7 for Low Temp. or for A453 Gr 660 (A-286) for Hydrogen Sulfide.
(2) For obsolete 16¾″ 5000 psi WP (7500 psi Test) flange.

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GLOSSARY OF BOPE AND ASSOCIATED TERMS

-A-

ACCUMULATOR - A pressure vessel, precharged with nitrogen above a movable barrier, used in the BOPE actuating system to accumulate and store hydraulic fluid under pressure.

ACCUMULATOR BACKUP - A particular type of emergency backup system consisting of additional accumulators that are normally isolated from the working bank(s) of accumulators in the actuating system.

ACCUMULATOR SIZE FACTOR - A number by which the required working fluid volume may be multiplied to arrive at the total accumulator bottle volume necessary for the accumulator unit. This factor is a function of the precharge pressure and the rated working pressure of the accumulator unit.

ACCUMULATOR UNIT (Actuating Unit, Closing Unit) A compact assembly of pumps, valves, accumulators, and other items used to maintain and restore the volume of working fluid needed to operate the components of the wellhead stack.

ACTUATING SYSTEM (Operating and Control System, Closing System) - The entire array of equipment that stores, pumps, and controls the hydraulic fluid needed to operate the components of the wellhead stack. Consists of the accumulator unit, emergency backup system, control manifold, remote operating station(s), and the control lines to the wellhead equipment. In subsea equipment, also includes the control pods, subsea accumulators, and other specialized items.

ACTUATING UNIT - *See* Accumulator Unit.

ANCHOR STRING - The string of casing inside of which pressures are directly affected by well-control activities using the BOP stack. Usually, the innermost casing string that is connected to, or hung inside the casinghead.

ANNULAR PREVENTER (Bag Preventer) - A hydraulically or pneumatically operated device that can seal the annular space around almost any object in the well bore. Most can seal off an open hole in an emergency. Compression or inflation of some type of elastomer packing element effects the seal.

API RING - *See* Ring-joint Gasket.

AUXILIARY EQUIPMENT - The accessories to the BOP stack that assist in preventing or controlling kicks. Consists of the fill-up line, the kelly cock(s), the safety valve(s), and the internal preventer(s).

-B-

BOP - Abbreviation for Blowout Preventer.

BOPE - Abbreviation for Blowout Prevention Equipment.

BACKUP SYSTEM - *See* Emergency Backup System.

BAG PREVENTER - *See* Annular Preventer.

BAILING GATE - A full-closing gate valve, usually operated manually, that can be installed above the casinghead to provide a means of closing off the well bore when a regular BOP stack is not required.

BALL VALVE - A valve containing a ball with a hole through it. The ball can be rotated so the hole is either in line with, or at right angles to, the center line of the pipe to which the valve is attached. May or may not be full throughbore. Not to be used for any type of choking or throttling activity.

BANJO BOX - A large-capacity, thick-walled drilling spool used when drilling with air. Absorbs turbulence, reduces annular velocities, and routes returning air and drill cuttings to the blooie line.

BELL NIPPLE (Flow Nipple, Mud Riser, Pitcher Nipple) A component of the BOP stack or marine riser system, installed as the uppermost element. It has an inside diameter equal to or greater than the throughbore of the preventers. It is belled at the top to guide tubulars into the hole and equipped with a side outlet to direct mud returns to the flow line. Usually equipped with a second side outlet for the attachment of the fill-up line.

BLIND RAMS (Blank, CSO, Complete Shut Off, Master Rams) - Rams that are not intended to seal off against any tubular goods in the well bore. They seal against each other to close off the hole. *See also* Ram-Type Preventer.

BLIND-SHEAR RAMS - Blind rams with a built-in cutting blade that will shear pipe in the hole, allowing the blind-ram faces to seal the hole. Used primarily in subsea BOP stacks.

BLOOIE LINE - A large-diameter pipe used in air drilling operations that routes returning air and drill cuttings to a muffler. The line is equipped with dual-purpose high-pressure nozzles that spray either water to settle dust or sodium hydroxide and/or hydrogen peroxide to neutralize hydrogen sulfide.

BLOWOUT - An uncontrolled flow of well fluids and/or formation fluids from a well bore to the surface or into lower-pressured subsurface zones (underground blowout).

BLOWOUT PREVENTER (BOP) - A valve attached to the casinghead of a well, allowing the well to be sealed at the surface and confining well fluids to the well bore.

BLOWOUT PREVENTER DRILL (Preventer Drill) - A training procedure to ensure rig crews are familiar with the correct operating practices to be followed in the use of the BOPE. A dry run of all blowout prevention actions, up to and including closing a preventer to shut in a well.

BLOWOUT PREVENTER STACK (Wellhead Stack) - The wellhead assembly of well control equipment, including all of the preventers, spools, and valves connected to the casinghead.

BLOWOUT PREVENTION EQUIPMENT (BOPE) - The entire array of equipment installed at a well to control kicks and prevent blowouts. Consists of preventers, an actuating system, a choke and kill system, and auxiliary equipment.

BOLL WEEVIL PLUG - *See* Test Plug.

BUTTERFLY VALVE - A fast-acting low-pressure valve having as the flow-control device a flat plate in the flow path that is wider than the inside diameter of the valve. The valve is closed by rotating the shaft to which the plate is attached until the sides of the plate contact the sides of the flow path.

-C-

CSO RAMS - *See* Blind Rams.

CASING HANGER - A slip and packer assembly that clamps around the top of a string of casing and fits into the casinghead, supporting a predetermined portion (weight) of the casing.

CASINGHEAD - A heavy steel fitting that connects to the first string of casing and provides a housing for the slips and packing assemblies by which subsequent strings of casing are suspended and the annuli sealed off.

CASINGHEAD TEST PLUG - *See* Test Plug.

CHECK VALVE - A valve that permits flow in one direction only.

CHOKE - A device with a fixed or variable aperture, used during kick-control procedures to control the flow rate and regulate the back pressure of liquid and/or gas in the well bore.

CHOKE LINE - The high-pressure piping connecting the BOP outlets or the side openings of the mud cross to the choke manifold.

CHOKE MANIFOLD (Control Manifold) - The system of valves, chokes, piping, and gauges used to control flow from the annulus and regulate pressures in the working string/annulus flow system.

CLAMP CONNECTION - A non-API pressure-sealing device used to join two equipment components together without using conventional, bolted flange joints. Each component is equipped with a clamp hub that is held to the hub of an adjacent component by a clamp containing two to four bolts.

CLOSING RATIO (Close Ratio) - The ratio of the kick pressure in the wellbore (y) to the preventer closing-chamber pressure necessary to close the preventer on a kick (x). Expressed as y:x.

CLOSING UNIT - *See* Accumulator Unit.

COMPLETE SHUTOFF (CSO) RAMS - *See* Blind Rams.

CONDUCTOR PIPE - A short string of pipe, usually of large diameter, used to protect the well bore against caving by unconsolidated surface formations and to convey the circulating mud returns to the flow line.

CONNECTION GAS - Analogous to *trip gas*, but occurs during a connection rather than a trip. An isolated occurrence of connection gas may not indicate increasing formation pressure, but a pattern of steadily increasing connection gas may do so.

CONTROL LINES - The hydraulic lines connecting the control manifold to the hydraulically controlled preventers and valves at the wellhead.

CONTROL MANIFOLD - A system of valves and piping used to control the flow of hydraulic fluid from the accumulator unit to the various components of the BOP stack.

CONTROL POD - A unitized assembly of control valves and regulators used to control the functions of the BOPE on a subsea stack.

CONTROL VALVE - The valve connected to the BOP stack that controls fluid access from the kill line to the well bore and from the well bore to the choke line. In a BOPE system requiring doubling-up (redundancy) of these valves on the choke and kill lines, the outer valve is referred to as the control valve.

CRITICAL WELL - A well in a sensitive location described in Section 1720a, *Title 14, California Code of Regulations*.

CSO RAMS - *See* Blind Rams.

CUP TESTER - A working-string-mounted accessory that is equipped with up-facing cups that seal against the casing walls when pressured from above and can be run through the preventer stack to any depth of interest in the casing string. May be used in lieu of a bridge plug or hanger-type test plug when testing BOPE.

-D-

DIVERTER SYSTEM - A system consisting of an annular preventer and large-diameter vent lines attached to the well head or the marine riser to direct any annular flow away from the rig. Its function differs from that of the regular preventers in that flow is not stopped, just directed away from the rig floor.

DOWNHOLE MUD MOTOR - *See* Mud Motor.

DRILL PIPE SAFETY VALVE - *See* Pipe Safety Valve.

DRILL STRING FLOAT - A check valve, run as an integral unit in the drill string, that allows fluid to be circulated down the drill string while preventing backflow.

DRILLING SPOOL - A component of the wellhead BOP stack with both ends either flanged or hubbed. It must have an internal diameter at least equal to the throughbore of the preventers and may have side openings for connecting auxiliary lines. (*See also* Mud Cross.)

DRIVE PIPE (Drive Casing) - A short string of large-diameter pipe driven into the ground or the sea floor to prevent sloughing of unconsolidated formations into the hole and/or conduct hole fluids to the flow line. (*See also* Conductor Pipe.)

-E-

EMERGENCY BACKUP SYSTEM - A required accessory system to the accumulator unit that provides an independent source of usable fluid, or equivalent, to operate the wellhead equipment. May be high pressure nitrogen type or accumulator type.

-F-

FILL-UP LINE - A line, usually connected into the bell nipple above the BOP stack, used to add mud to the hole during trips to keep the hole full.

FLANGED CONNECTION - An API-type connection employing two facing, bolted- or studded-plates with a deformable metal API ring-gasket seated in ring grooves to provide a pressure seal.

FLOW LINE - A line connecting the bell nipple at the top of the BOP stack to the hole-fluid storage and reconditioning area.

FLOW NIPPLE - *See* Bell Nipple.

FORMATION FRACTURE GRADIENT - The pressure per unit of true vertical depth that could be expected to fracture a formation at a particular point in the well bore. (Expressed in psi/ft.)

FORMATION PRESSURE GRADIENT - The known or estimated formation pressure per unit of true vertical depth. A normal formation pressure gradient may be assumed to equal that of a column of formation-density salt water extending from the depth in question to the surface, approximately 0.444 psi/ft. in California.

FOUR-WAY VALVE - A valve on the accumulator-unit manifold that controls the flow of hydraulic fluid to and from the wellhead equipment. Each valve has an inlet port from the accumulator(s) and output ports to the preventer opening line, the preventer closing line, and the accumulator unit reservoir.

FULL-HOLE INDICATOR - *See* Mud Return Indicator.

FULL-OPENING VALVE - Any valve that, in the open position, has a throughbore at least as large as the throughbore of the valve body, itself.

-G-

GATE VALVE - A valve utilizing a stem-driven sliding gate to open or close the flow passage. May or may not be full opening.

-H-

HANGER-TYPE TEST PLUG - *See* Test Plug.

HOLE-FLUID MONITORING EQUIPMENT - BOPE accessories mounted in the circulating system that indicate or record information concerning hole-fluid conditions. The equipment monitors the volume of fluid in the system, as indicated by the mud-pit level and may indicate the gas content, the presence or absence of flow, and/or the changing physical conditions of the fluid.

HYDROSTATIC GRADIENT - The pressure exerted per unit by true vertical height by a column of a particular liquid at rest. A function of fluid density, expressed in psi/ft.

HYDROSTATIC HEAD - The pressure that a column of fluid at rest exerts in all directions at any point in the column. A function of fluid density and true vertical height of the fluid column above a point.

-I-

INSIDE BLOWOUT PREVENTER - *See* Internal Preventer.

INTERNAL PREVENTER - A surface-installed working-string check valve that permits stripping back to bottom and reestablishing circulation to control a kick taken while tripping.

-K-

KELLY COCK, LOWER - A strippable full-opening valve mounted on the lower end of the kelly that may be closed to protect or isolate the rotary hose and standpipe system during kick-control operations.

KELLY COCK, UPPER - A ball-type or flapper-type valve mounted between the kelly and the swivel that performs the same function as the lower kelly cock and serves as a backup to the lower kelly cock in BOPE systems required to have both types.

KICK - The unwanted entry of formation fluids into the wellbore, resulting in a rise in the level of hole fluid in the storage system. If control is not reestablished, a kick may result in a blowout.

KILL LINE - A high-pressure line connecting the hole fluid pump(s) directly to the well bore beneath at least one preventer, permitting fluid to be pumped into the hole when a preventer is closed during a kick.

-L-

LOST CIRCULATION - Loss of hole fluid into the formation, resulting in lost or reduced returns, lowering the fluid level in the hole-fluid storage system, and possible loss of hydrostatic pressure that could lead to underbalance and the introduction of a kick.

LOWER MARINE RISER PACKAGE - A unitized array of equipment connected to the lower end of the marine riser. Contains variable equipment components, depending on the design of the BOPE system. Usually contains, from the bottom up, a high-pressure connector to the BOP stack, two control pods, and a flexible joint to the marine riser. May also contain an annular preventer, multiplex signal decoder(s), sonar signal receptors, etc. Usually, the package can be recovered separately from the BOP stack so the components can be worked on or the vessel can be moved without removing the preventers from a wellhead.

-M-

MARINE RISER - Large-diameter pipe system that provides a fluid pathway between ocean-floor equipment and the drilling vessel. Usually integrated with the choke and kill lines. Deep-water systems may be equipped with flotation devices to support part of the weight of the riser pipe, reducing the strain on the riser-tensioning system.

MASTER VALVE - The valve in the choke and kill lines closer to the BOP stack in a BOPE system that requires redundant valves.

MINIMUM INTERNAL YIELD PRESSURE - The lowest internal pressure at which permanent deformation of a given casing will occur.

MUD CROSS - A component of the wellhead BOP stack with both ends either flanged or hubbed, having side openings for connecting auxiliary lines and an internal diameter at least equal to the throughbore of the preventers. (*See also* Drilling Spool.)

MUD MOTOR (Downhole Mud Motor) - The principal component of a type of hole-drilling system that does not require rotation of the drill string by means of a rotary table at the surface. Instead, the bit is turned by a downhole turbine that is powered by circulating fluid.

MUD RETURN INDICATOR (Full-hole Indicator) - A device attached to the pitcher nipple or flow line that senses flow and indicates to the driller that the hole is full of circulating fluid.

MUD RISER - *See* Bell Nipple.

MUD VOLUME MEASURING DEVICE - Any device in the circulating system that is installed for the purpose of indicating the level or volume of circulating fluid.

MUD WEIGHT RECORDER - A graphical display of the output from any device in the hole-fluid monitoring system that measures fluid density continuously.

MUFFLER - An enlargement of the blooie line at the separator end that suppresses noise caused by air drilling and/or steam discharge.

-O-

OPENING RATIO (Open Ratio) - The ratio of the opening chamber pressure (z) necessary to open a preventer to the pressure in the wellbore (y). Expressed as z:y.

OPERATING AND CONTROL SYSTEM - *See* Actuating System.

OVERBURDEN - The pressure exerted on a formation at any depth due to the weight of the overlying rocks. Generally assumed to be 1 psi/ft. of burial depth.

-P-

PACKOFF - *See* Stripper.

PIPE RAMS - Rams with contoured faces designed to seal off the annular space around pipe. Unless the newer variable rams are used, a separate preventer with appropriately sized rams is required for each size of pipe used in an operation. (*See also* Ram-type Preventer.)

PIPE SAFETY VALVE - A full-opening valve positioned on the rig floor, with connections or adapters to match the pipe in use. The valve is used to close off the inside of the working string to prevent internal flow.

PIT DRILL - A category of blowout drill that measures the crew's ability to respond to kick indications. It takes the crew from the initial signs of a kick to the point where they observe the flow line for spontaneous flow. A preventer is not actuated unless the drill is permitted to continue.

PIT LEVEL INDICATOR - A level-measuring device installed in a mud pit to measure relative changes in the volume of a particular pit.

PIT VOLUME TOTALIZER - A device in the hole-fluid monitoring system that accepts the output from a series of pit level indicators and that displays the total level change from all of the monitored pits.

PITCHER NIPPLE - *See* Bell Nipple.

PLUG VALVE - A valve in which the operator is a tapered plug with a hole through it. The plug can be rotated so the hole is either in line with, or at right angles to, the center line of the pipe to which the valve is attached. It may or may not be a full-throughbore valve. This valve is not to be used for any type of choking **or throttling** activity.

PRECHARGE PRESSURE - The pressure to which an accumulator vessel is charged with nitrogen before pumping hydraulic fluid into it for storage and use. Depending on the type of accumulator, this pressure will be above a guided float or inside an elastomer bladder or diaphragm. Also, the pressure remaining in an accumulator vessel after all the stored fluid has been driven out.

PRESSURE REGULATING VALVE - An adjustable valve in the accumulator-unit control manifold that regulates the pressure of the hydraulic fluid in the operating chambers of the wellhead equipment.

PREVENTER - *See* Blowout Preventer.

PREVENTER DRILL - *See* Blowout Preventer Drill.

PUMP-DOWN PREVENTER - An alternative to the surface-mounted internal preventer. A small-diameter check valve that can be dropped into the working string and pumped down until it locks into a profile sub near the bottom of the string. Once it has been pumped into place, it permits pumping down through the working string while preventing back flow.

-R-

RAM-TYPE PREVENTER - A wellhead-mounted gate valve that seals off open space in the well bore by forcing two horizontal gates (rams) into sealing contact against one another and against a seal seat in the top of the preventer body. (*See also* Pipe Rams and Blind Rams.)

RATED WORKING PRESSURE - The highest pressure that an item of equipment should be required to contain in normal use.

REMOTE STATION - A panel containing a series of control buttons or levers that will operate the four-way valves on the control manifold from a remote location.

RING-JOINT GASKET - A metal ring that fits into the ring groove on a flange-type or clamp-type connection, providing the pressure seal as the flange or clamp bolts are tightened. These gaskets are designated as type “R”, solid rings with oval or octagonal cross sections. They are usually used in lower-pressure installations, or type “RX” and “BX”, having irregular octagonal cross sections with pressure-balancing holes drilled vertically through the body of the ring. These are referred to as pressure-energized rings.

ROTATING HEAD - A rotating pressure-sealing device used when performing well operations with air, gas, or foam as a circulating fluid, or in any other conditions that would, or might, result in an underbalance of wellbore pressure versus formation pressure.

-S-

SAFETY VALVE - *See* Pipe Safety Valve.

SHEAR RAMS - *See* Blind-Shear Rams.

SLAB GATE VALVE - A mechanical, positive-sealing device consisting of a hydraulically operated, single-gate valve that is used as the base for a geothermal BOP stack.

SPOOL - *See* Drilling Spool.

STRIPPER (Packoff) - A device, usually employed immediately beneath the working floor, containing an elastomer packing element that depends on pressure below the element to effect a tight seal in the annulus. Used primarily to strip hole fluid from the outside of the pipe and contain low- or moderate-hole pressures when tripping pipe. Cannot be depended on to contain high hole pressures.

STRIPPING DRILL - A special category of blowout-preventer drill in which a few joints of pipe are stripped through the preventer(s) that would be used for stripping operations in the event of a well kick.

SURFACTANT - A chemical element or compound that tends to concentrate at a molecular interface. Used in drilling fluids to control the degree of emulsification, aggregation, interfacial tension, foaming, defoaming, wetting, etc.

SWABBING - Temporary lowering of the effective pressure against the formation due to incorrect pipe-pulling procedures. The pipe is pulled at a rate that does not permit hole fluid to flow past the tool joints fast enough to maintain the hydrostatic pressure at the bottom of the hole.

-T-

TARGETED TURN - A method of changing direction in pressure piping that involves installing a bull plug or blind flange opposite the fluid-entry arm in one arm of a tee or cross. This will inhibit erosion.

TEST JOINT (Testing Sub) - A pipe joint or sub designed for use with a test plug to provide a closing surface when pressure testing the pipe rams or annular preventer.

TEST PLUG (Hanger-type Test Plug, Boll Weevil Plug, Casinghead Test Plug) - A tool designed to seat in the casinghead below the BOP stack. It permits high-pressure testing of BOPE system components without risking pressure damage to the casing string or exposed formations.

TESTING SUB - *See* Test Joint.

TOP DRIVE - A powered swivel that rotates the drill string.

TRIP - The process of removing all or part of the working string from the well bore (tripping out), running the string into the well bore (tripping in), or both processes in sequence (round tripping).

TRIP GAS - An accumulation of gas that enters the well bore when hole-fluid circulation is interrupted during a trip. Usually attributable to lowering hydrostatic pressure due to swabbing. Should be viewed as a warning sign to the crew, because it is a possible indication of increasing formation pressure.

-U-

UNDERGROUND BLOWOUT - A situation in which kick fluids are forced into a formation at a depth other than that of fluid entry, usually because of excessive surface-pressure containment. In cases where the BOP anchor string is cemented to a shallow depth, this type of blowout usually will occur immediately below the shoe of the casing, from which point well fluids are likely to come to the surface outside the well bore (through fractures).

USABLE FLUID - The volume of fluid that can be withdrawn from an accumulator unit between the full working pressure of the unit and the lowest acceptable pressure for the type of unit involved (1,000 psi for 750 psi precharge units and 1,200 psi for 1,000 psi precharge units).

-W-

WELLHEAD STACK - The entire array of blowout-prevention equipment that is connected to the casinghead. Consists of the pitcher nipple (on surface stacks), the preventers, and the drilling spools (mud crosses).

WING LINE - Any tubular line that is attached to the sides of a device containing the principal fluid pathway. The wing line provides for fluid ingress and/or egress and serves as a point of attachment for valves, chokes, and other control devices. Wing lines usually are attached to the mud cross, the choke manifold, or the wellhead.

WING VALVE - Any valve installed in a wing line. The term usually applies to valves installed near the attachment of the wing line to the device providing the principal fluid pathway.

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