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BLOWOUT PREVENTION In California

Equipment Selection and Testing

California Department of Conservation
Division of Oil, Gas, and Geothermal Resources

STATE OF CALIFORNIA
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DEPARTMENT OF CONSERVATION
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This manual is for guidance in establishing blowout prevention requirements. Nothing herein is to be regarded as an approval or disapproval of any specific product.

DIVISION OF OIL, GAS, AND GEOTHERMAL RESOURCES
HAL BOPP, *State Oil and Gas Supervisor*

BLOWOUT PREVENTION in California

Equipment Selection and Testing

by
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California Department of Conservation
Division of Oil, Gas, and Geothermal Resources

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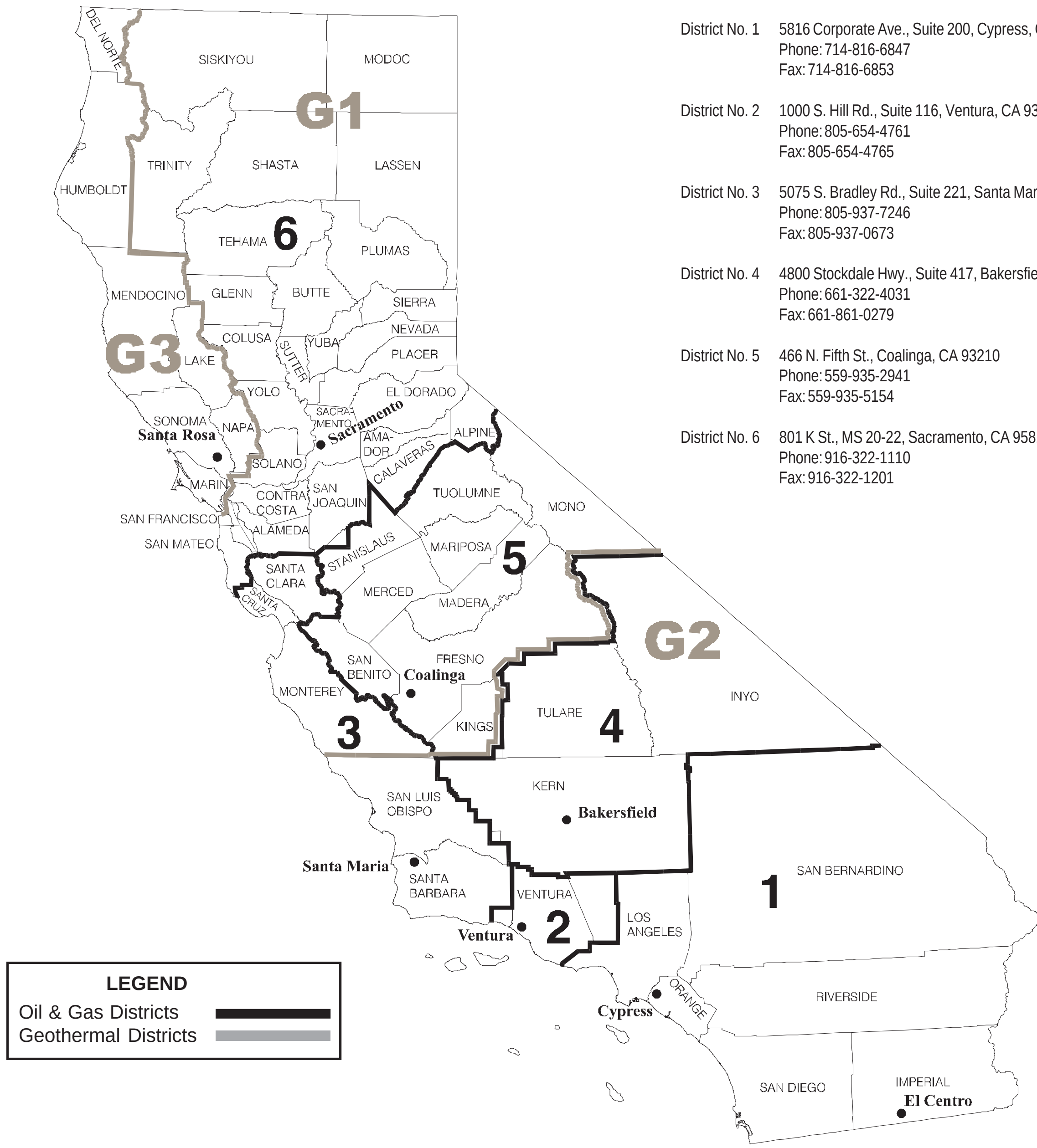

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1. SCOPE

Section 3219, *Division 3,* of the *Public Resources Code (PRC)* of the State of California states, in part, that operators must equip wells..."with casings of sufficient strength, and with such other safety devices as may be necessary, in accordance with methods approved by the supervisor, and shall use every effort and endeavor effectually to prevent blowouts, explosions, and fires". Additional requirements for casing and blowout prevention equipment (BOPE) are provided by several sections of *Title 14* of the *California Code of Regulations,* particularly Section 1722.5, which establishes this manual as the guide for engineers of the Department of Conservation, Division of Oil, Gas, and Geothermal Resources..."in establishing the blowout prevention equipment requirements specified in the division's approval of proposed operations".

Besides serving as a guide for Division of Oil, Gas, and Geothermal Resources (division) engineers, the manual is designed to help operator personnel in planning their well operations. By serving as a single-source guide to blowout prevention equipment (BOPE) used in oil, gas, and geothermal operations in California, the manual will help operators conform to the BOPE requirements of the *Public Resources Code* and the *California Code of Regulations*.

The manual is oriented primarily toward the equipment involved in blowout prevention. Therefore, several important aspects of kick control and blowout prevention practices, such as casing programs, kick-control procedures, and crew training are discussed only briefly, if at all. This does not mean that the division places reduced emphasis on these aspects of blowout prevention. In fact, Section 1722(c), *Title 14, California Code of Regulations* requires that "For certain critical or high-pressure wells designated by the supervisor, a **blowout prevention and control plan,** including provisions for the duties, training, supervision, and schedules for testing equipment and performing personnel drills, shall be submitted by the operator to the appropriate division district deputy for approval". Once approved, a copy of the plan must be available at each well site for use by the operator and contractor personnel for training rig crews. The plan is also used by division inspectors when evaluating blowout prevention (BOP) preparedness. For critical or high-pressure wells, the division may elect to witness one or more of the required weekly blowout drills in the company of the operator's representative or contractor's foreman. (Division engineers are not authorized to initiate a blowout drill without the knowledge of either the operator's representative or the contractor's foreman.)

The operator must post at the well site of each well a copy of the division's Permit to Conduct Well Operations (Form OG 111). This report contains, among other provisions, the class of BOPE required and lists any tests and procedures, including BOPE tests, that must be witnessed by a division representative.

Section 2 of the manual outlines the division's requirements for BOPE, emphasizing the fact that the requirements are tailored to the individual well.

Section 3 explains the function and operating characteristics of BOPE components. For the purposes of the manual, BOPE components are grouped into five major functional areas: preventers, actuating system, choke and kill system, auxiliary equipment, and hole-fluid monitoring equipment. In most cases, a list of division requirements for a component follows the operational explanations.

Section 3-A describes the additional equipment and modification of BOPE components necessary for installing and operating blowout prevention equipment on the ocean floor.

Section 4 describes the equipment and modification of BOPE components necessary for drilling geothermal wells.

Section 5 outlines inspection and testing procedures for all components of the BOPE array, except the hole-fluid monitoring system. These procedures may be modified in the field by a division inspector to conform to current policy, but complete testing may be ordered if the apparent condition of the BOPE is such that a question exists as to the ability of the components to function satisfactorily.

During the preparation of this manual, personnel were consulted from oil, gas, and geothermal operating companies, equipment manufacturing firms, service companies, petroleum consulting firms, and industry organizations, and many of their suggestions are included. Much material is based on industry and trade publications, particularly the specifications and recommended practices of the American Petroleum Institute (API).

2. CLASSIFICATION AND SELECTION OF EQUIPMENT

2-1 GENERAL

a. The **classification and selection system** described in this section is used by the Division of Oil, Gas, and Geothermal Resources to arrive at uniform requirements for blowout prevention equipment in California. Each proposed program of well operations is reviewed by a division engineer and, if warranted by the operation, one or more BOPE classifications are assigned. These classifications are based on accepted engineering practices based on the proposed operations, surface environment, geological conditions, and known or anticipated subsurface pressures.

b. A **complete BOPE classification** (e.g., Class III B 3M) is composed of three elements that identify, respectively, the division's requirements for blowout prevention equipment, hole-fluid monitoring equipment, and rated working pressure of the weakest component of the wellhead stack and choke system. In this example, the well is to be equipped with Class III BOPE, as outlined in paragraph 2-2d and a Class B hole-fluid monitoring system, as outlined in paragraph 2-3b. The equipment must have a rated working pressure minimum of 3,000 psi (3M). The three elements may be assigned in any combination that will provide adequate blowout protection.

   Table 1, is provided as a quick guide to BOPE classification (shown in box d) that will probably be required by the division for any well, given the proposed operation (box a), the well environment (box b), and the anticipated surface pressure (box c).

c. Each **proposed well operation** will be considered in its entirety by a division engineer before BOPE classifications are assigned. More than one BOPE classification will be assigned if warranted by different stages of the proposed casing program. The classification(s) will be specified on the division's Permit to Conduct Well Operations (Form OG 111).

d. Paragraph 2-2 describes the **minimum equipment** for each class of BOPE. Additional requirements may be specified, on an individual well basis, to modify the BOPE to handle any anticipated demands or to bring it into conformance with current API specifications and arrangements.

e. The **stack arrangement**s, depicted in Figures 1 through 6 of this section, are for illustrative purposes only. The operator may use any desired arrangement of preventers and drilling spools, provided the total system meets the BOPE classification assigned by the division and provisions have been made to control the well under any predictable conditions.

f. The following **BOP stack component codes**, as used in paragraphs 2-2c and 2-2d and in Figs. 1 through 6 of this manual, are taken from API RP 53: *Blowout Prevention Equipment for Drilling Wells*. The codes are:

   A = annular-type blowout preventer.

   G = rotating head.

   R = single ram-type preventer with one set of rams.

   Rd = double ram-type preventer with two sets of rams.

   Rt = triple ram-type preventer with three sets of rams.

   S = drilling spool with side outlet connections for choke and kill lines.

   M = 1,000 psi rated working pressure.

   Components are listed from the bottom component to the top component, that is from the uppermost piece of permanent wellhead equipment or the bottom of the preventer stack.

g. If conditions warrant, the division may approve the installation of a **diverter system** when a well is to be drilled to a shallow total depth. However, in areas where steam injection or other sources of shallow overpressure might present a threat of blowout, the division may require an operator to install a diverter

Table 1. Guidelines for selection of BOPE and hole fluid monitoring equipment.

Shaded area indicates the solution to the example in paragraph 2-4.

a	Proposed Well Operations	Drill, redrill, or deepen	Exploratory														X			X		X	X	X	X
			Development					X								X	X		X	X				X		
		Rework	Expose add'l zone				X				X	X		X	X							X				
			Same zone	X	X	X			X	X			X													
b	Well Environment		Offshore-Surface			X				X		X	X		X		X			X		X	X	X	X	
			Offshore-Subsea																							X
			Onshore-Critical			X				X		X	X		X		X			X		X	X	X		
			Onshore-Noncritical	X	X		X	X	X		X			X		X		X	X		X					
c	Anticipated surface pressure category: $\left(\frac{\text{Anticipated zone pressure - 500}}{\text{Depth x Anticipated fluid gradient}}\right)^*$		High= > 1.0						X				X	X					X		X	X		X	X	X
			Med.=0.1-1.0		X					X	X				X	X		X		X			X		X	X
			Low= < 0.1	X		X	X	X				X					X									
d	Blowout Prevention Equipment Class			I	II				II**				III									IV				V
	Hole Fluid Monitoring Equipment Class			—				A	—							B						—	B	C		

INSTRUCTIONS:

1. Select the horizontal line in each of boxes a, b, and c that most nearly describes the well in terms of proposed operation, well environment, and anticipated zone pressure category.

2. Move to the right until an "x" is found under each consideration in a single vertical column.

3. Move down that column to box d to determine the equipment classes for BOPE and Hole Fluid Monitoring Equipment.

* Fluid gradient (psi/ft.) = $\frac{\text{fluid density (lb./ft.}^3\text{)}}{144\ \text{(in.}^2\text{/ft.}^2\text{)}}$

** For wells in these columns, consider requiring a nonmanual activating system.

system on shallow casing strings before it becomes practicable to install one of the regular classes of BOPE, as described in paragraph 2-2. If a diverter system is required by the division, it must be designed to direct the flow of well fluids away from the working area of the rig, and away from public roads, buildings, or sensitive environments in the immediate area. The crew must be trained in the use of the system.

Proper installation and use of a diverter system will minimize the possibility of the crew shutting in the well completely when this might damage formations that would be exposed to annulus pressures. This will protect against formation fracture that could cause an underground blowout (the escape of hole fluid through the walls of the hole), which could cause injury or loss of life, property loss, and/or loss of natural resources.

2-2 CLASSIFICATION OF BLOWOUT PREVENTION EQUIPMENT

a. A **diverter system**, when required, must be installed on the conductor casing, drive pipe, or first surface casing before drilling out the shoe of that string of casing, and must be maintained in good working order until an adequate BOPE anchor string has been cemented in the hole and the required BOPE system has been installed.

The well crew must be trained in the use of the diverter system and a weekly diverter drill held for each crew. Records of the drills must be entered in the daily log book.

The diverter system will contain, as a minimum, the following components:

1. **Either** a special purpose annular preventer, designed specifically as a diverter, with an outlet below the packing element that opens automatically as the diverter is closed, **or** a regular annular preventer with special attention to the valving and venting requirements listed in paragraphs 2-2a2 and 2-2a3, which follow.

2. A six-inch (onshore drilling wells) or eight-inch (offshore drilling wells) minimum ID outlet below the diverter, equipped with a full-opening gate, ball, plug, or butterfly valve or an easily broken (frangible) diaphragm that will prevent the flow of wellbore fluids through the line during normal operations, but which opens automatically or may be quickly and easily opened manually before-or-as the diverter is closed.

   As an alternative to this valve, the system may be designed as an open flow system as depicted in Figure 13A of this manual and in the illustrations accompanying Section 2-A, API RP 53 (*see* Selected References).

   For a *rework operation* in which side openings on the existing wellhead are smaller than 6 inches ID, a mud cross with 6-inch outlets must be installed between the wellhead and the diverter. If the operator intends to install a vent line(s) *smaller than 6 inches* to the side opening(s) of the wellhead, permission to do so must be obtained from the division engineer who evaluates the proposal, and the 6-inch requirement must be waived on the Permit to Conduct Well Operations, form OG111.

3. A diverter vent system of the same minimum ID as the diverter outlets that fulfills the following requirements:

   a) For *onshore wells*, a single vent line may be installed. This line must terminate in a sump or other suitable receptacle at a location from which it is unlikely that effluent from the vent line will be blown or carried toward the rig or toward any building, public road, or sensitive environment in the immediate area.

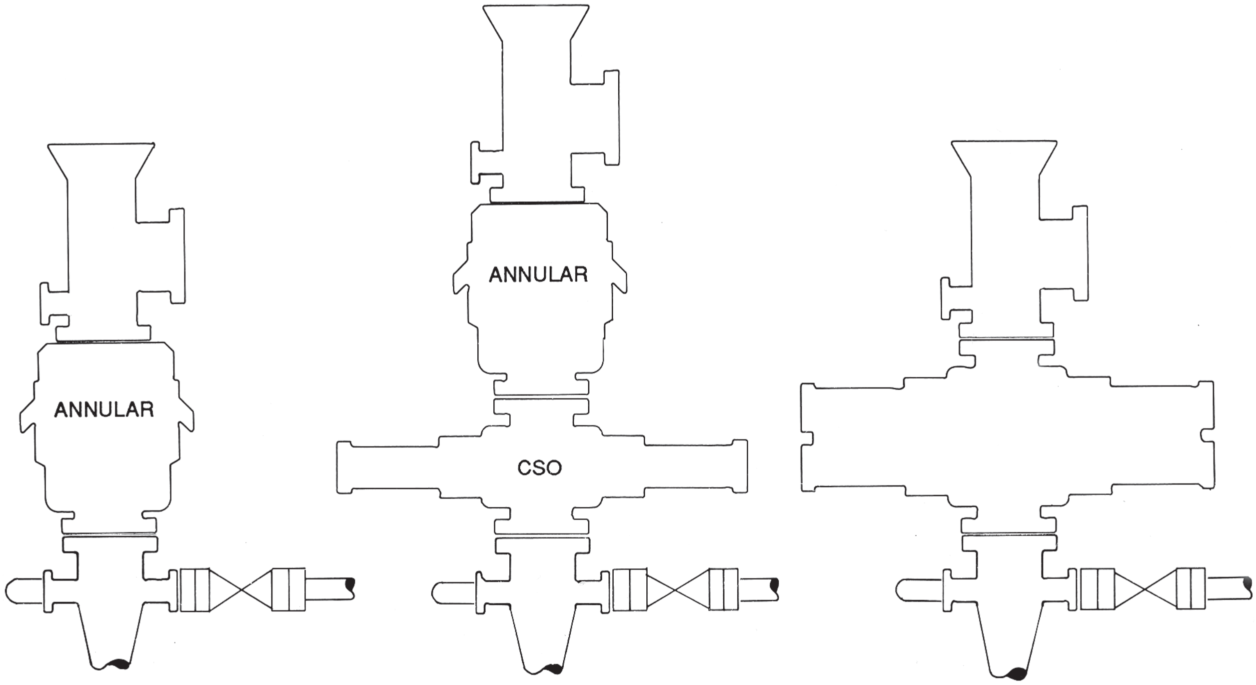
   b) For *offshore wells*, multiple vent lines must be installed, with a selector valve system that will permit the crew to select the downwind line or the gas stack.

   c) *Vent lines must be as straight as practicable,* with any necessary turns targeted as described in paragraphs 3-4a7. The line(s) must be anchored securely to prevent whipping or vibration damage, and no sleeve-type couplings may be used.

b. A **Class I BOPE system** consists of, as a minimum, any device installed at the surface that is capable of complete closure of the well bore with the pipe out of the hole. The device must be closed whenever the well is unattended. See paragraph 3-2a1 for additional requirements if an annular preventer is used as the closing device.

c. A **Class II BOPE system** (API arrangements A, Rd, RR, or RA) consists of, as a minimum, the following components:

1. Annular and/or ram-type preventers capable of providing complete closure of the well bore, and



API ARRANGEMENT A

API ARRANGEMENT RA

API ARRANGEMENT RR or Rd

API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.

EXAMPLE CLASS II BOPE STACKS

FIGURE 1

closure around the pipe in use. See paragraph 3-2a1 for additional requirements if an annular preventer is used alone (API arrangement A).

2. Manual closing devices, unless a remote actuating system is specified.

3. Access line of 2-inch minimum outside diameter into the well bore below the preventer(s), with suitable valves and fittings for pressure relief or well killing operations.

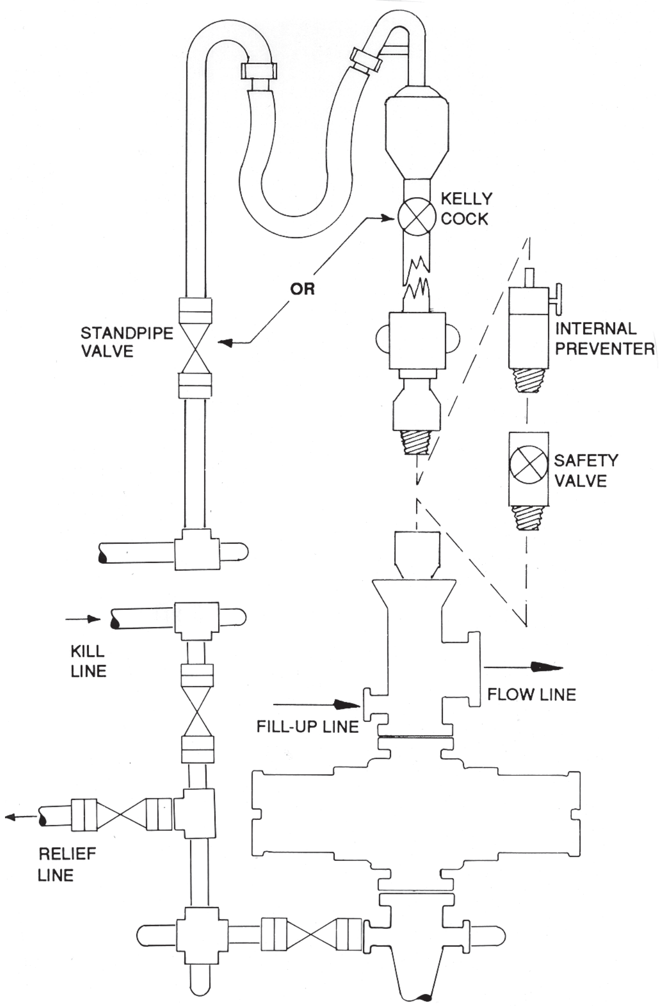
4. Fill-up line into the bell nipple above the preventer stack, but not in direct line with the flow line.*

5. Kelly cock or standpipe valve.*

6. Full-opening safety valve readily available on the rig floor, in the open position, with fittings adaptable to all pipe to be used in the proposed operations. If this valve is of the type that is made up into the working string, it must fit through the wellhead equipment in use.

7. Internal preventer inside the pipe in use, or readily available at the rig in the open position, with fittings adaptable to the safety valve required by 2-2c6. This valve must fit through the wellhead equipment in use and must be stored in such a position or identified in such a manner that it will not be the first valve installed by the crew in response to a kick taken while tripping pipe.*

* For workover operations not requiring a drilling-type circulating system, requirements 4, 5, and 7 do not apply.



API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.

EXAMPLE CLASS II BOPE INSTALLATION
API ARRANGEMENT RR or Rd
FIGURE 2

d. A **Class III BOPE system** (API arrangements SRdA, SRRA, or RSRA) consists of, as a minimum, the following components:

1. Annular preventer, blind (CSO) ram-type preventer, and pipe ram-type preventer(s) capable of closure around all pipe, exclusive of drill collars and short "stinger" strings of smaller pipe, which are to be used in the proposed operations. All ram-type preventers must have independent, positive-locking devices.

2. An actuating system with the primary source of energy (usually the accumulator unit) located at least 50 feet from the well bore. The actuating system must be capable of accomplishing ALL of the following actions within *two minutes* with the source of power to any charging pump(s) disconnected:

   a) Close and open one ram-type preventer;

   b) Close the annular preventer on the smallest-diameter pipe for which pipe rams have been installed;

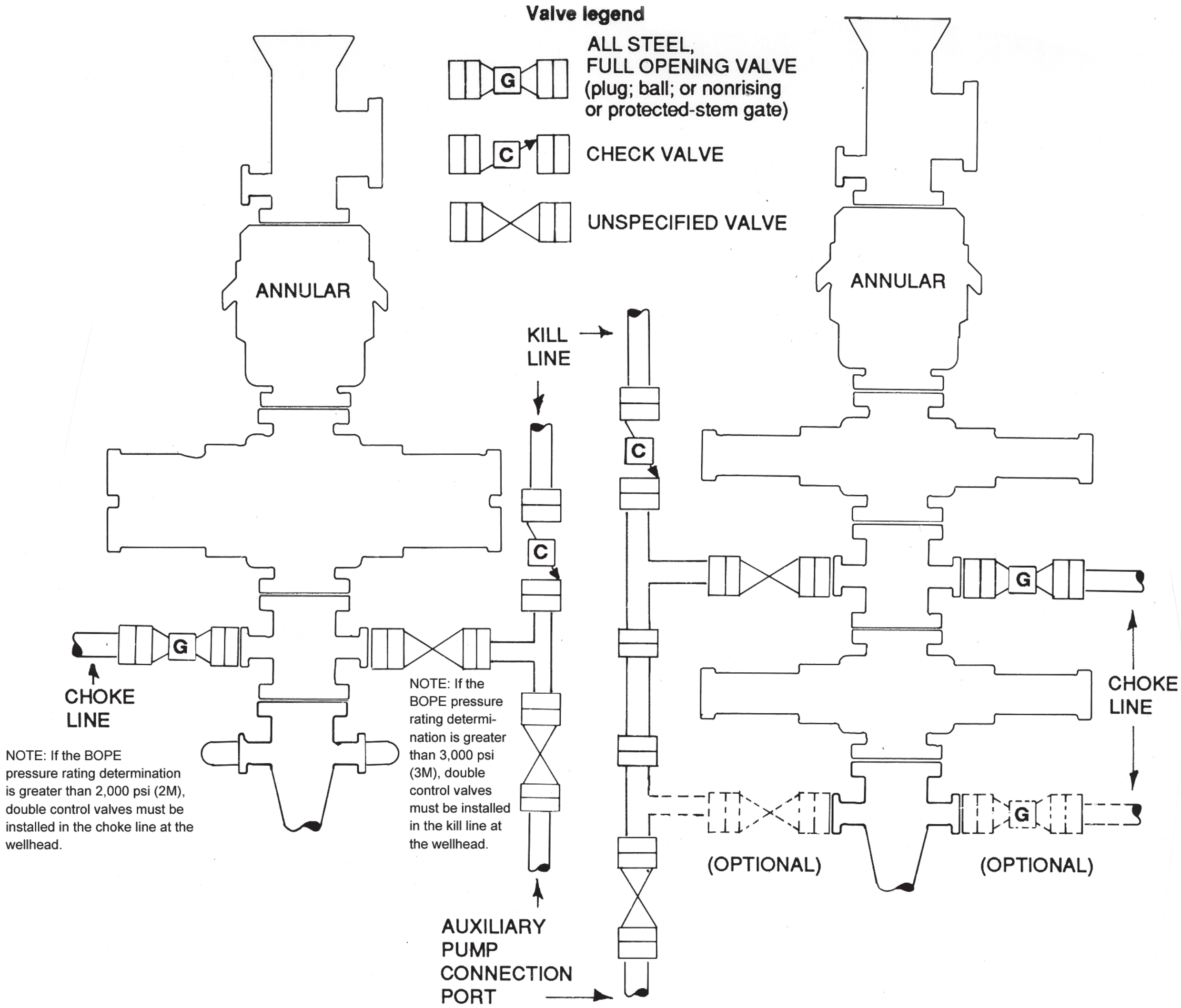
   c) Perform all immediate kick-control responses involving any installed auxiliary equipment for which this actuating system serves as the source of energy.

   For preventers with very large operating volumes, the two-minute time limit may be extended to cover the time during which fluid is moving continuously in the system to perform this sequence of actions.

   If the actuating system is of the hydropneumatic type, it must contain enough USABLE FLUID to accomplish actions a), b), and c) just discussed with the source of power to the accumulator pump disconnected.

   NOTE: USABLE FLUID is defined as the volume of fluid that may be withdrawn from the accumulator(s) without lowering the pressure in the actuating system below 1,000 psi, or 200 psi above the manufacturer's recommended accumulator precharge pressure, whichever is greater. The value of 1,000 psi is selected as the minimum acceptable pressure because it approximates the pressure required to hold an annular preventer closed on open hole.

   In addition, an emergency backup system must be installed at the source of energy for the actuating system. The backup system must contain enough usable fluid, or enough usable fluid equivalent, to close the annular preventer on open hole and open any installed remote-controlled valves on the choke line. The backup system must utilize an independent, explosion-safe source of actuating energy.



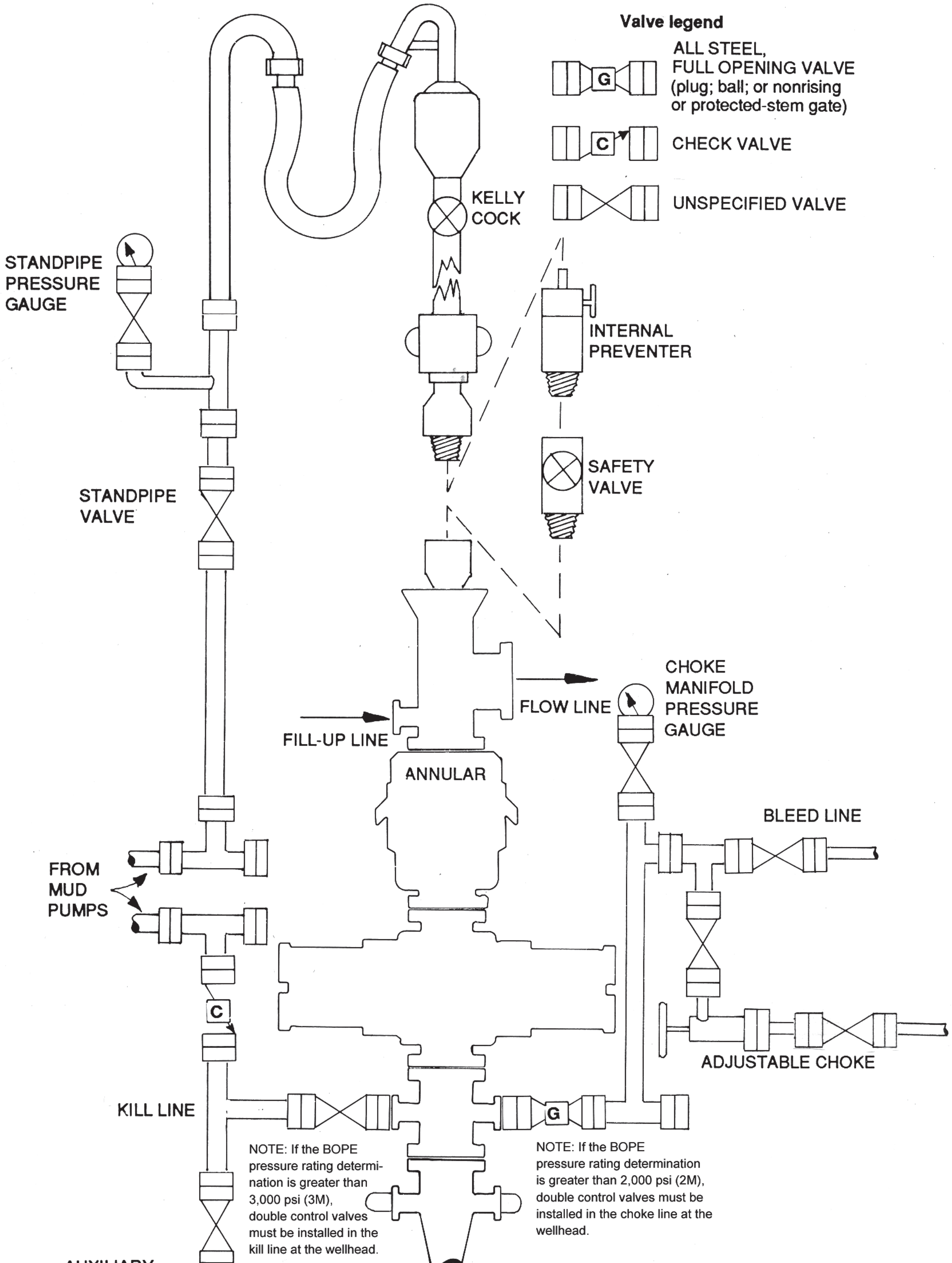
API ARRANGEMENTS SRdA AND SRRA **API ARRANGEMENT RSRA**

API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.

EXAMPLE CLASS III BOPE STACKS

FIGURE 3



API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.

EXAMPLE CLASS III BOPE INSTALLATION

API ARRANGEMENT SRRA or SRdA

FIGURE 4

3. Dual control stations: one within 10 feet of the driller's station if the configuration of the drilling floor permits (preferably on the nearest exit route from the rig floor), and the other at the actuating system.

4. Kill line of 2-inch minimum outside diameter, containing at least one control valve, one check valve, and fittings for an auxiliary pump connection. See paragraph 3-4b for specific requirements. The kill line should enter the well bore beneath one set of pipe rams, with an optional auxiliary connection below the lowermost rams.

5. Choke system containing at least one control valve, one adjustable choke, a bleed line, and an accurate pressure gauge. See paragraph 3-4a for specific requirements. Normally, the choke line outlet from the well bore will be located beneath one set of pipe rams. However, if the operator's BOPE guidance recommends that the pipe rams be placed in a "master gate" position at the base of the BOPE stack (API arrangement RSRA), the division will approve the placement of the choke line outlet between the pipe rams and the CSO rams with the provision that the operator maintains an extra set of pipe rams at the well site to exchange for the CSO rams if a kick is taken with pipe in the hole. The division will not approve placement of the choke line outlet above all of the ram preventers. In offshore and critical onshore areas, the choke line must discharge into existing production facilities or a suitable container.

6. Kelly cock, standpipe valve, and standpipe pressure gauge.*

7. Fill-up line into the bell nipple above the preventer stack, but not in direct line with the flow line.*

8. Full-opening safety valve, readily available on the rig floor in the open position, with fittings adaptable to all pipe to be used in the proposed operations. If this valve is of the type that is made up into the working string, it must fit through the wellhead equipment in use.

9. Internal preventer inside the pipe in use, or readily available on the rig floor in the open position, with fittings adaptable to the safety valve required by 2-2d8. This valve must fit through the wellhead equipment in use and must be stored in such a position, or identified in such a manner, that it will not be the first valve installed by the crew in response to a kick taken while tripping pipe.*

* For workover operations not requiring a drilling-type circulating system, requirements 6, 7, and 9 do not apply.

e. A **Class IV system** consists of, as a minimum, the following components:

   1. Annular preventer, blind (CSO) ram-type preventer, and two or more pipe ram-type preventer(s) capable of closure around all pipe, exclusive of drill collars and short "stinger" strings of smaller pipe, to be used in the proposed operations. The blind rams must be above at least one set of pipe rams. All ram-type preventers must have independent, positive-locking devices.

   2. An actuating system with the primary source of energy (usually the accumulator unit) located at least 50 feet from the well bore. The actuating system must be capable of accomplishing ALL of the following actions within *two minutes* with the source of power to any charging pump(s) disconnected:

      a) Close and open one ram-type preventer;

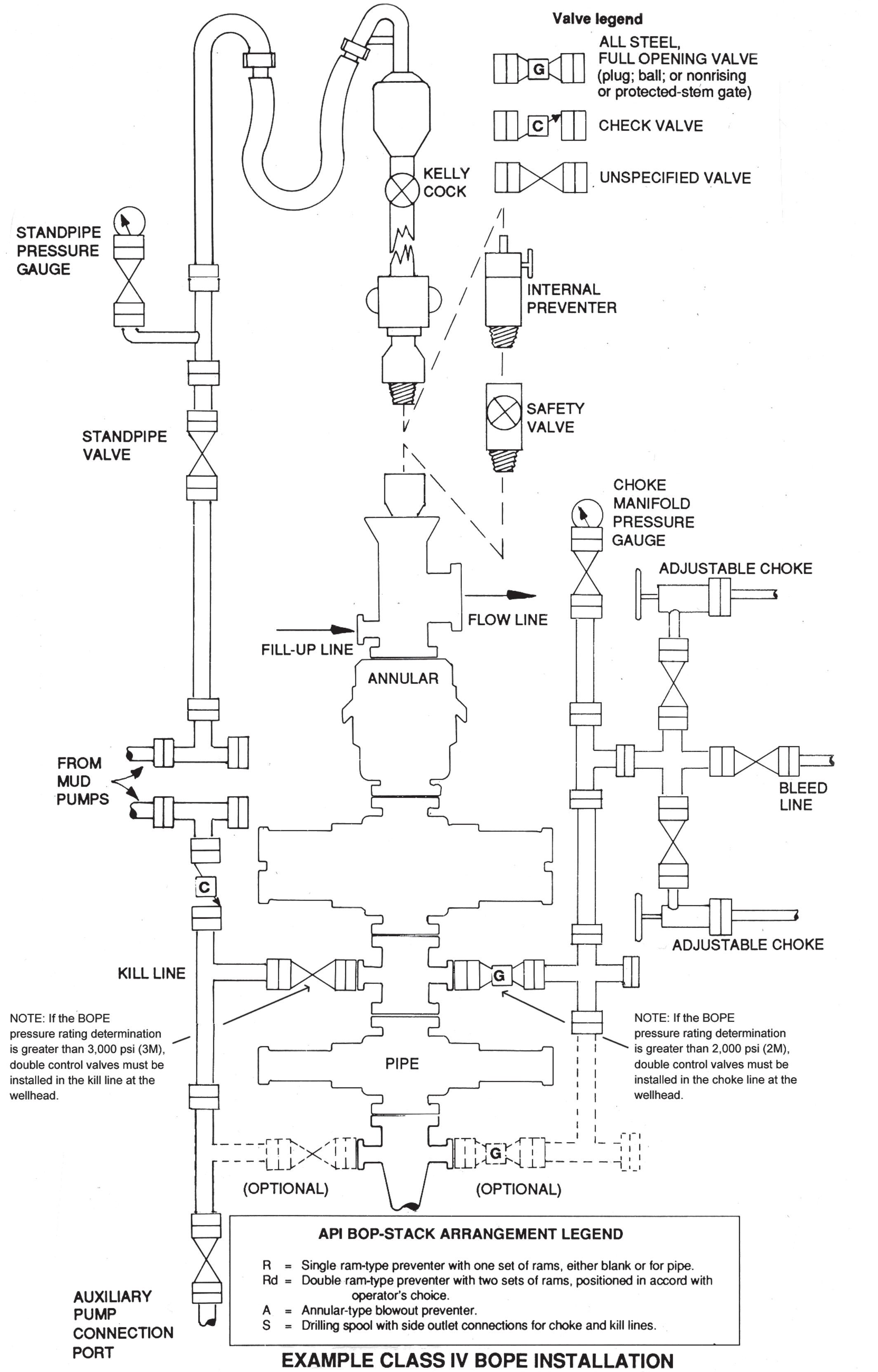
      b) Close the annular preventer on the smallest-diameter pipe for which pipe rams have been installed;

      c) Perform all immediate kick-control responses involving any installed auxiliary equipment for which this actuating system serves as the source of energy.

      For preventers with very large operating volumes, the two-minute time limit may be extended to cover the period of time during which fluid is moving continuously in the system to perform this sequence of actions.

      If the actuating system is of the hydropneumatic type, it must contain enough USABLE FLUID to accomplish a), b), and c) just discussed with the source of power to the accumulator pump disconnected.

      NOTE: USABLE FLUID is defined as the volume of fluid that may be withdrawn from the accumulator(s) without lowering the pressure in the actuating system below 1,000 psi, or 200 psi above the manufacturer's recommended



API BOP-STACK ARRANGEMENT LEGEND

R = Single ram-type preventer with one set of rams, either blank or for pipe.
Rd = Double ram-type preventer with two sets of rams, positioned in accord with operator's choice.
A = Annular-type blowout preventer.
S = Drilling spool with side outlet connections for choke and kill lines.

EXAMPLE CLASS IV BOPE INSTALLATION

API ARRANGEMENT EITHER RSRRA or RSRdA

FIGURE 5

accumulator precharge pressure, whichever is greater. The value of 1,000 psi is selected as the minimum acceptable pressure because it approximates the pressure required to hold an annular preventer closed on open hole.

In addition, an emergency backup system must be installed at the source of energy for the actuating system. The backup system must contain enough usable fluid, or enough usable fluid equivalent, to close the annular preventer on open hole and open any installed remote-controlled valves on the choke line. The backup system must utilize an independent, explosion-safe source of actuating energy.

3. Dual control stations: one within 10 feet of the driller's station if the configuration of the drilling floor permits, (preferably on the nearest exit route from the rig floor), and the other at the actuating system.

4. Kill line of 2-inch minimum outside diameter, containing at least one control valve, one check valve, and fittings for an auxiliary pump connection. See paragraph 3-4b for specific requirements. The kill line should enter the well bore beneath one set of pipe rams, with an optional auxiliary connection below the lowermost preventer.

5. Choke system containing at least one control valve, two adjustable chokes, a bleed line, and an accurate pressure gauge. See paragraph 3-4a for specific requirements. The choke line outlet from the well bore should be located above one set of pipe rams, with an optional auxiliary connection below the lowermost preventer. In offshore and critical onshore areas, the choke line must discharge into existing production facilities or a suitable container.

6. Upper and lower kelly cocks installed in the kelly at all times. See paragraph 3-5c for kelly cock requirements when using a downhole mud motor or a top drive system.*

7. Standpipe valve, and standpipe pressure gauge.*

8. Fill-up line into the bell nipple above the preventer stack, but not in direct line with the flow line.*

9. Full-opening safety valve, readily available on the rig floor in the open position, with fittings adaptable to all pipe to be used in the proposed operations. If this valve is of the type that is made up into the working string, it must fit through the wellhead equipment in use.

10. Internal preventer inside the pipe in use, or readily available on the rig floor in the open position, with fittings adaptable to the safety valve required by 2-2e9. This valve must fit through the wellhead equipment in use and must be stored in such a position, or identified in such a manner, that it will not be the first valve installed by the crew in response to a kick taken while tripping pipe.*

f. A **Class V BOPE system** *applies only in the case of a subsea BOPE stack* (*see* paragraph 3A-3 for requirements and Figure 6 for BOP stack configuration).

2-3 CLASSIFICATION OF HOLE-FLUID MONITORING EQUIPMENT

a. **Class A** - Any device capable of a reasonably accurate determination of mud system gains and losses.

b. **Class B**

1. Mud pit level indicator with audible alarm.

2. Any device, such as a pump stroke counter, trip tank, etc., capable of a reasonably accurate determination of the volume of fluid required to keep the hole full when pulling pipe.

c. **Class C**

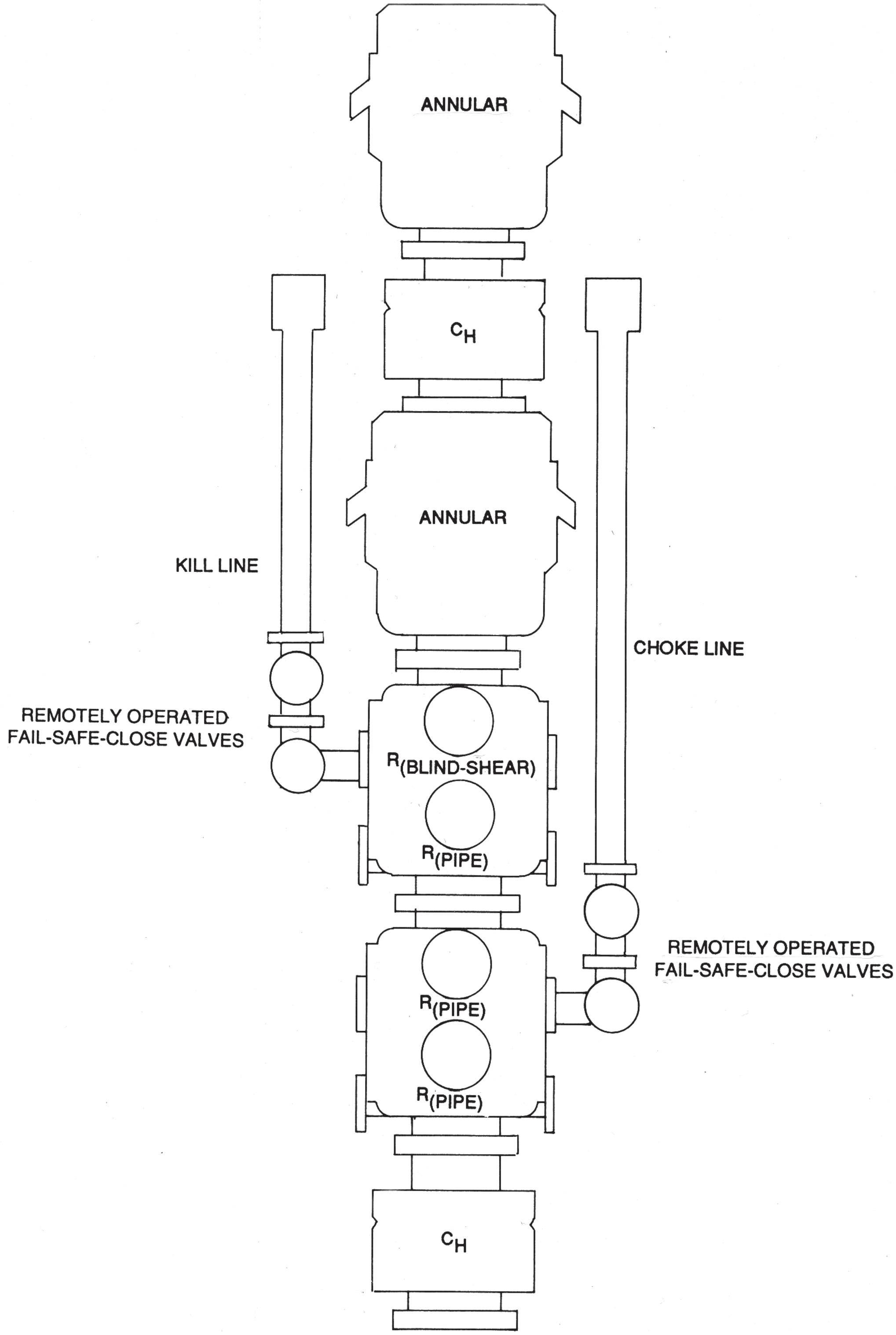
1. A recording mud pit level indicator or pit volume totalizer system to determine mud pit volume gains and losses. This indicator must include both visual and audible warning devices.

2. A mud volume measuring device capable of accurately determining the mud volume necessary to keep the hole full when pulling pipe from the hole.

3. A mud return or full-hole indicator to show when returns have been obtained, or when they occur unintentionally, and that returns essentially equal the pump discharge rate.

If slim hole operations are anticipated, the mud return indicator should be of an electromag-

* For workover operations not requiring a drilling-type circulating system, requirements 6, 7, 8, and 10 do not apply.



EXAMPLE CLASS V BOP STACK

(SUBSEA INSTALLATION)

FIGURE 6

netic or impulse design because of their increased sensitivity and accuracy, rather than the customary paddle-type flow line indicator.

4. Gas-detection equipment to monitor the drilling mud returns for hydrocarbons and hydrogen sulfide (H_2S) at critical locations along the mud system.

2-4 SELECTION OF BOPE AND HOLE-FLUID MONITORING EQUIPMENT

The classification system outlined in paragraphs 2-2 and 2-3 is applied by the division to each proposed well so the required equipment will provide an adequate margin of safety. Table 1, *Guidelines for Selection of BOPE and Hole-Fluid Monitoring Equipment,* is intended to assist selection in areas where field rules do not apply.

EXAMPLE:

An operator proposes to sidetrack a bad liner in a well located in a residential area. There are no flowing wells in the field. The zone pressure is 800 psi and the oil gravity is 19^{o} API. The depth to the top of the zone is 3,600 feet. What class of equipment should be used?

SOLUTION:

Well Conditions

Proposed well operations:	Redrill-development
Well environment:	Onshore critical
Anticipated surface pressure:	Medium pressure

From Table 1: Class III B equipment should be used.

2-5 SELECTION OF PRESSURE RATING

Two separate pressures may have to be considered before selecting the pressure rating portion of a BOPE classification, *one for a final pressure determination and another if an interim determination is requested.*

a. The **Maximum Predicted Casing Pressure (MPCP)** is the basis for the selection of a ***final*** BOPE pressure rating. The MPCP is the maximum known or estimated bottom-hole pressure (BHP) at total depth, minus the back pressure exerted by a column of gas extending from total depth to the surface. In areas where no zone pressure data are available, an acceptable BHP may be estimated by multiplying the proposed total vertical depth by a normal formation pressure gradient of 0.465 psi/foot. The BHP may then be multiplied by the MPCP/BHP ratio for that depth (Fig. 7) to obtain a MPCP for the hole. This pressure condition would occur if all liquids were removed from the hole due to gas entry or lost circulation and would place the greatest demand on the BOPE.

b. The **Maximum Allowable Casing Pressure (MACP)** is the basis for selection of an ***interim*** BOPE pressure rating.

For a drilling well containing hole fluid of a given density, the MACP is the surface pressure that would be likely to fracture the formation immediately below the shoe of the BOPE anchor string or rupture any casing string subjected to that pressure.

For a workover, the MACP is usually determined by the density of the workover fluid and the depth to open perforations or, occasionally, the minimum internal yield pressure of the BOPE anchor string of casing. See Appendix E for an explanation of the relationship between the MACP applied against open hole and the MACP applied through perforated casing.

In either case, the MACP must be recalculated whenever additional casing is cemented and when the hole-fluid density is changed significantly. This pressure will be the lesser of the following two pressures:

1. ***Formation Fracture Pressure*** - the surface pressure that, when added to the hydrostatic pressure exerted by the column of fluid in a hole, could reasonably be expected to fracture the formation at the shoe of the anchor string or at the perforations, whichever occurs higher in the hole. A value for this pressure may be approximated from Figure 8. A more accurate fracture pressure may be obtained by performing a leakoff test of the exposed formation.

2. ***Casing Yield Pressure*** - the surface pressure that, when added to the hydrostatic pressure exerted by the column of hole fluid at any depth, would result in an overbalance (with respect to the pressure behind the casing at that depth) that exceeds the minimum internal yield strength of that casing as listed in Appendix D.

SAMPLE PROBLEM FOR DETERMINING THE BOPE PRESSURE RATING

An operator proposes to reperforate the producing zone in a well for which the BOPE requirement has been determined to be Class II. The operator provides the following information concerning the well:

8-5/8", 32#, J-55 casing cemented at 4,000'.

5-1/2", 17#, J-55 liner cemented from 3,960' to 4,500'.

Water shut-off (WSO) on 5-1/2" x 8-5/8" lap.

Liner perforated from 4,400' to 4,500'.

Total depth: 4,500'.

Producing clean, 38^{o} API gravity oil (sp. gr. 0.835).

Static fluid level at 1,500' below surface.

Shut-in casing pressure: 50 psig.

Proposed workover fluid weight: 73.5 pcf.

Formation pressure gradient : 0.465 psi/ft.

SOLUTION:

STEP 1. Determine the Maximum Predicted Casing Pressure (MPCP) as follows:

a. Calculate the BHP by using fluid level, pressure gradient, and shut-in casing pressure information and the following formulas. (Pressure gradient of the produced fluid x height of the fluid column) + shut-in casing pressure.

   The *pressure gradient of the produced fluid* is the product of the specific gravity of the produced fluid and the pressure gradient of fresh water.

   Therefore, BHP = [(0.835 x 0.433)(4,500 - 1,500)] + 50 = 1,135 psi

b. From Figure 7, obtain the MPCP/BHP ratio for the total depth and multiply by the BHP to obtain the MPCP.

   The MPCP/BHP for a TD of 4,500'= 0.91
   MPCP = 0.91 x 1,135 = 1,033 psi.

STEP 2. Calculate the Maximum Allowable Casing Pressure (MACP) for the existing hole conditions.

a. Obtain the Formation Fracture Pressure from Figure 8 as follows:

   1) Enter the chart from the *left* margin at the depth of the exposed formation (i.e., top perfs, at 4,400').

   2) Move to an interpolated point (between 70 pcf and 80 pcf fluid curves) that would represent the proposed workover fluid weight (73.5 pcf).

   3) Move to the *upper* margin to obtain the pressure applied through the perfs.

   4) Read the Formation Fracture Pressure (1,450 psi).

   NOTE: If the liner in this example had been installed with a hanger instead of being cemented in place, the formation would be exposed to well pressure at the shoe of the 8-5/8" casing at 4,000'. In this case, the *lower* margin of the graph (Fig. 8) would have applied, and the Formation Fracture Pressure would have been 960 psi.

b. Calculate the Casing Yield Pressure for the anchor string of casing as follows:

   1) Calculate the pressure gradient of the proposed workover fluid using the factor 0.0069 (i.e., 0.433 / 62.4) to convert fluid weight in pcf to pressure gradient. 73.5 x 0.0069 = 0.510 psi/ft.

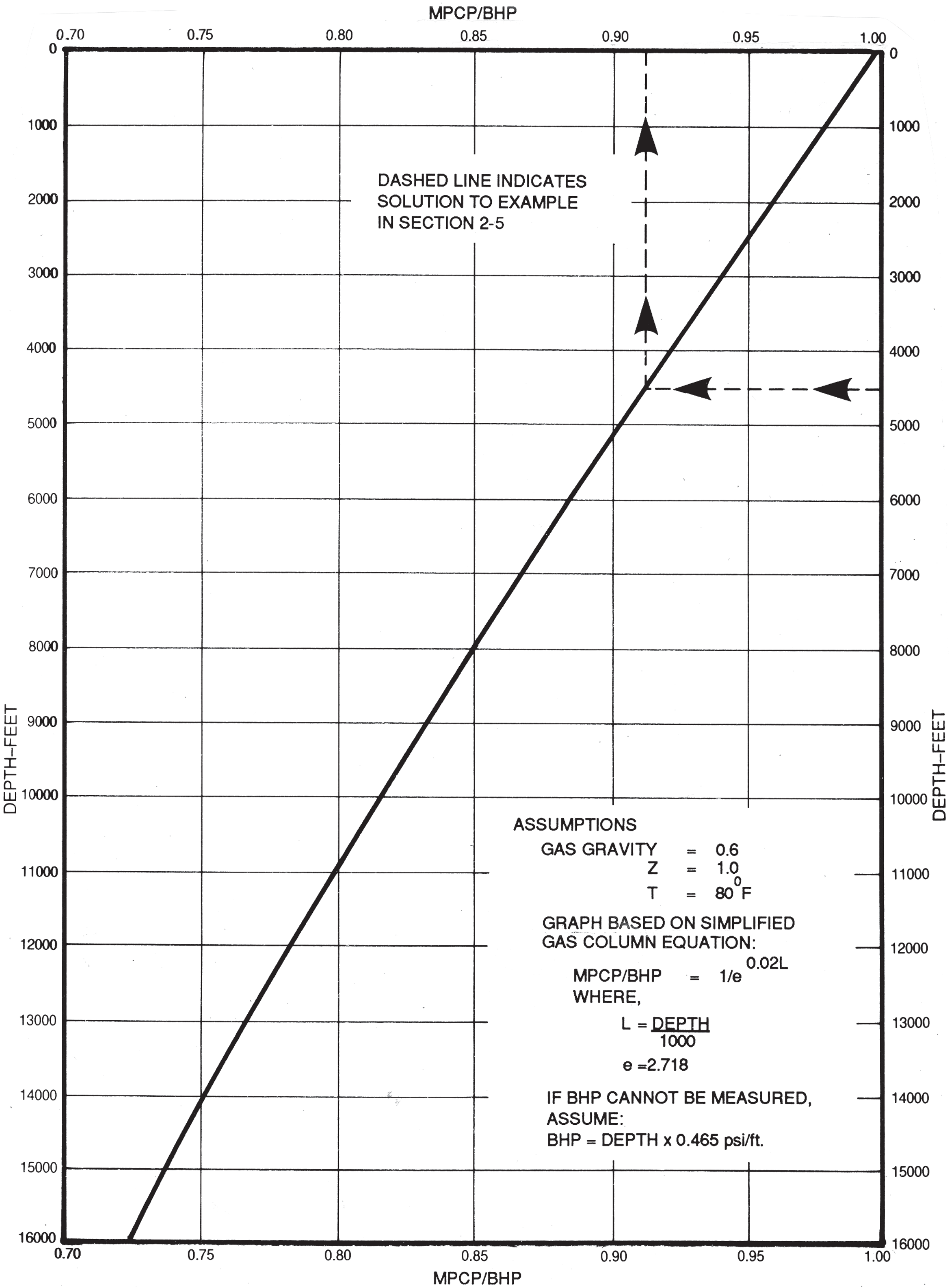
   2) Calculate the overbalance gradient with respect to the formation pressure gradient by multiplying the pressure gradient of the proposed workover fluid by the formation pressure gradient. 0.510 - 0.465 = 0.045 psi/ft.

   3) Calculate the overpressure at the top of the liner lap by multiplying the overbalance gradient by the depth to the liner top. 3,960 x 0.045 = 178 psi.

   4) Subtract the overpressure from the minimum internal yield pressure of the anchor string using Appendix D to obtain the casing yield pressure. For 8-5/8" 32# J-55 casing, the minimum internal yield pressure is 3,930 psi.

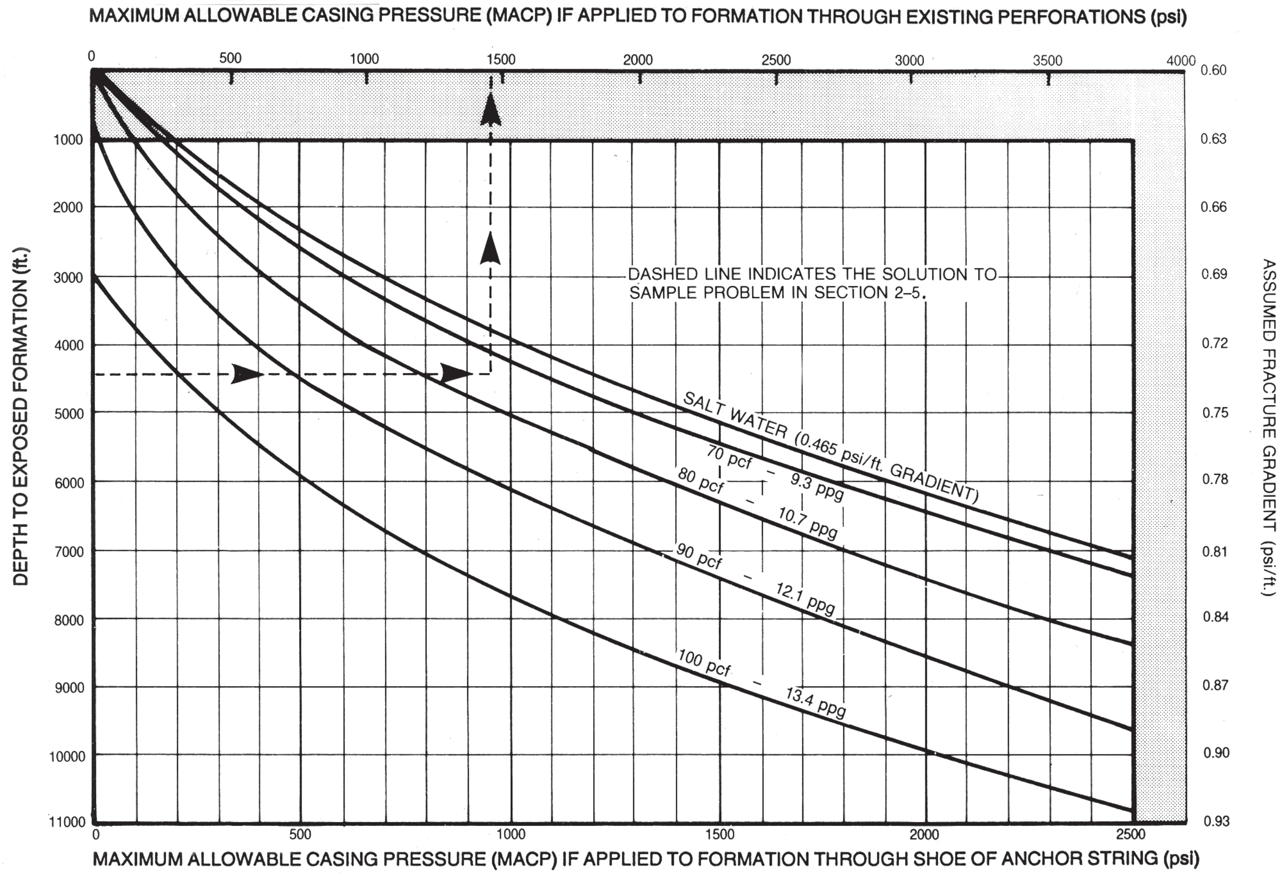
   Casing Yield Pressure= 3,930 - 178 = 3,752 psi

   NOTE: For a well in which the anchor string is made up of several grades of casing, or in areas where a uniform formation pressure gradient does not apply from surface to total depth, the casing yield pressure may have to be calculated for several points in the hole to determine a minimum value for the well.



RATIO OF MAXIMUM PREDICTED CASING PRESSURE TO BOTTOM HOLE PRESSURE ($^{MPCP}/_{BHP}$) vs. DEPTH

FIGURE 7



MAXIMUM ALLOWABLE SURFACE PRESSURE (MACP) vs. DEPTH AND ASSUMED FRACTURE GRADIENT

FIGURE 8

PROCEDURE FOR USE OF FIGURE 8[15]

ASSUMPTIONS:
1. Formation pressure is 0.465 psi/ foot at all depths.
2. Fracture gradient behaves according to Cristman.[14]

In areas where these assumptions are known to be invalid, the MACP as determined from the graph must be multiplied by one or both of the following factors, as applicable:

1. $$\frac{\text{Known fracture gradient}}{\text{Fracture gradient from right margin of graph}}$$

and/or

2. $$\frac{\text{Known formation pressure}}{0.465 \times \text{depth}}$$

INSTRUCTIONS:

1. Enter the graph from the left margin at the depth to the shoe of the BOPE anchor string or the top of the production perfs., as applicable.

2. Move horizontally to a point corresponding to the density of the fluid to be used during the proposed operations. Interpolate if necessary.

3. Move vertically from that point to the *lower* margin if there is to be open hole below the shoe of the BOPE anchor string. Move to the *upper* margin if the pressure is to be applied to existing production perforations in a fully cased hole (*see* Appendix E).

[15] Superior figures refer to the list of *Selected References* at the end of the report.

c. The MACP for existing hole conditions is the lesser of the amounts in Step 2, a.4 and b.4 of this solution. In this case, the MACP is the formation fracture pressure of 1,450 psi.

STEP 3. The minimum final working pressure rating for the BOPE is 1,033 psi (the MPCP from Step 1 of this solution). The lowest rated working pressure rating commonly available in BOP equipment is 2,000 psi; therefore, the BOPE classification would be *Class II 2M.* In this case, there is no requirement for hole-fluid monitoring equipment. The MACP that should be brought to the attention of the rig crew is 1,450 psi. It is unlikely that the surface pressure would reach that value, since the MPCP is only 1,033 psi.

2-6 ADDITIONAL REQUIREMENTS

The following requirements are mandatory for *all* operations conducted on offshore, onshore critical, or high-pressure areas.

a. **All required BOPE must be inspected** and, if applicable, actuated periodically to ensure operational readiness. The minimum frequency of this inspection/actuation is as follows:

   1. At least once during each eight-hour tour, the following are to be performed:

      a) Check accumulator pressure.

      b) Check emergency backup system pressure.

      c) Check hydraulic fluid level in accumulator unit reservoir.

      d) Actuate all audible and visual indicators and alarms.

   2. On each trip, but not more often than once each 24-hour period, the following are to be actuated:

      a) Pipe rams (before starting out of the hole).

      b) Blind (CSO) rams (after pulling the pipe from the hole).

      c) All installed kelly cocks.

      d) Drill pipe safety valve.

      e) Internal preventer.

      f) Adjustable chokes.

      g) Hydraulic valves, if any.

   3. Once each seven days, the following are to be actuated:

      a) The annular preventer on drill pipe or tubing.

      b) All gate valves in the choke and kill systems.

      c) All manually operated BOP locking devices.

b. **BOPE practice drills and training sessions** must be conducted at least once each week for each crew. These drills may be performed in conjunction with the operational readiness tests outlined in paragraph 2-6a, and must provide training for each member of the crew to ensure (as a minimum):

   1. A clear understanding of the purpose and the method of operation of each preventer and all associated equipment.

   2. The ability to recognize the warning signs that accompany a kick.

      If the proposed work involves any slim hole operations, the crew must be alerted to the fact that the warning signs of a kick can develop very rapidly during slim hole operations because of the reduced volume of the annulus. The crew must be continuously alert to any kick signs such as changes in pit volume or hole-fluid flow rate, changes in the physical properties of the hole fluid, and unexplained changes in the drilling rate and/or the pump pressure.

   3. A clear understanding of each crew member's station and duties in the event of a kick while drilling, while tripping pipe, while drill collars are in the preventers, and while out of the hole.

   4. A clear understanding of the maximum allowable casing pressure (MACP) and the significance of the pressure for well conditions that exist at the time of the drill or training session.

c. A **record** of all inspections, tests, crew drills, and training sessions must be kept in the daily log book.