

Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells

API RECOMMENDED PRACTICE 53
THIRD EDITION, MARCH 1997

REAFFIRMED, SEPTEMBER 1, 2004



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Exploration and Production Department

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FOREWORD

These recommended practices were prepared by the API Subcommittee on Blowout Prevention Equipment Systems. They represent a composite of the practices employed by various operating and drilling companies in drilling operations. In some cases, a reconciled composite of the various practices employed by these companies was utilized. This publication is under the jurisdiction of the American Petroleum Institute, Exploration & Production Department's Executive Committee on Drilling and Production Practices.

API Recommended Practice 53, First Edition, February 1976, superseded and replaced API Bulletin D13, *Installation and Use of Blowout Preventer Stacks and Accessory Equipment*, February 1966. The Second Edition was issued in May 1984.

Drilling operations are being conducted with full regard for personnel safety, public safety, and preservation of the environment in such diverse conditions as metropolitan sites, wilderness areas, ocean platforms, deep water sites, barren deserts, wildlife refuges, and arctic ice packs. Recommendations presented in this publication are based on this extensive and wide ranging industry experience.

The goal of these voluntary recommended practices is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling equipment, and preservation of the environment for land and marine drilling operations. These recommended practices are published to facilitate the broad availability of proven, sound engineering and operating practices. This publication does not present all of the operating practices that can be employed to successfully install and operate blowout preventer systems in drilling opera-

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Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells

1 Scope

1.1 PURPOSE

The purpose of these recommended practices is to provide information that can serve as a guide for installation and testing of blowout prevention equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating). Blowout prevention equipment systems are composed of all systems required to operate the blowout preventers (BOPs) under varying rig and well conditions. These systems are: blowout preventers (BOPs), choke and kill lines, choke manifold, hydraulic control system, marine riser, and auxiliary equipment. The primary functions of these systems are to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled volumes to be withdrawn from the wellbore. In addition, diverter systems are addressed in this Recommended Practice, though their primary purpose is to safely divert flow rather than to confine fluids to the wellbore. Refer to API Recommended Practice 64 for additional information on diverter systems. Marine risers are not dealt with in detail in this document. Refer to API Recommended Practice 16Q for additional information on marine drilling risers.

1.2 WELL CONTROL

Procedures and techniques for well control are not included in this publication since they are beyond the scope of equipment systems contained herein (refer to API Recommended Practice 59).

1.3 BOP INSTALLATIONS

In some instances, this publication contains a section pertaining to surface BOP installations followed by a section on subsea BOP installations. A delineation was made between *surface* and *subsea* equipment installations so these recommended practices would also have utility in floating drilling operations. Statements concerning surface equipment installations also generally apply to subsea equipment installations.

1.4 EQUIPMENT ARRANGEMENTS

Recommended equipment arrangements, as set forth in this publication, are adequate to meet specified well conditions. It is recognized that other arrangements may be equally effective and can be used in meeting well requirements and promoting safety and efficiency.

1.5 LOW TEMPERATURE OPERATIONS

Although operations are being conducted in areas of extremely low temperatures, a section specifically applicable to this service was not included since current practice generally results in protecting existing BOP equipment from this environment.

1.6 IN-THE-FIELD CONTROL SYSTEM ACCUMULATOR CAPACITY

It is important to distinguish between the standards for in-the-field control system accumulator capacity established here in Recommended Practice 53 and the design standards established in API Specification 16D.

API Specification 16D provides sizing guidelines for designers and manufacturers of control systems. In the factory, it is not possible to exactly simulate the volumetric demands of the control system piping, hoses, fittings, valves, BOPs, etc. On the rig, efficiency losses in the operation of fluid functions result from causes such as friction, hose expansion, control valve interflow as well as heat energy losses. Therefore, the establishment by the manufacturer of the design accumulator capacity provides a safety factor. This safety factor is a margin of additional fluid capacity which is not actually intended to be usable to operate well control functions on the rig.

For this reason, the control system design accumulator capacity formulas established in Specification 16D are different from the demonstrable capacity guidelines provided here in Recommended Practice 53.

The original control system manufacturer shall be consulted in the event that the field calculations or field testing should indicate insufficient capacity or in the event that the volumetric requirements of equipment being controlled are changed, such as by the modification or changeout of the BOP stack.

2 References

2.1 STANDARDS

The following standards contain provisions which, through reference in this text, constitute provisions of this standard. All standards are subject to revision and users are encouraged to investigate the possibility of applying the most recent editions of the standards indicated below:

API

Spec 5L	<i>Line Pipe</i>
Spec 6A	<i>Wellhead and Christmas Tree Equipment</i>
Spec 16A	<i>Drill Through Equipment</i>
Spec 16C	<i>Choke and Kill Systems</i>
Spec 16D	<i>Control Systems for Drilling Well Control Equipment</i>
RP 16Q	<i>Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems</i>
RP 17D	<i>Subsea Wellhead and Christmas Tree Equipment</i>
RP 49	<i>Drilling and Drill Stem Testing of Wells Containing Hydrogen Sulfide</i>
RP 59	<i>Well Control Operations</i>
RP 64	<i>Diverter Systems Equipment and Operations</i>
RP 500	<i>Classification of Locations for Electrical Installations at Petroleum Facilities</i>

ANSI¹

B1.20.1	<i>General Purpose Pipe Threads</i>
B31.3	<i>Chemical Plant and Petroleum Refinery</i>

ASME²

Boiler and Pressure Vessel Code

ASTM³

D-1418	<i>Practice for Rubber and Rubber Lattices—Nomenclature</i>
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NACE⁴

MR 01-75	<i>Material Requirements Sulfide Stress Cracking Resistant metallic Materials for Oilfield Equipment</i>
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2.2 OTHER REFERENCES**SPE⁵**

SPE 20430	<i>Mud Gas Separator Sizing and Evaluation</i> , G.R. MacDougall, December 1991
SPE 23900	<i>A Field Guide for Surface BOP Equipment Inspections</i> , W.J. Kandel and D.J. Streu, February 1992

¹American National Standards Institute, 1430 Broadway, New York, N.Y. 10018

²American Society of Mechanical Engineers, 22 Law Drive, Box 2300, Fairfield, NJ 07007-2300

³American Society for Testing and Materials, 1916 Race Street, Philadelphia, PA 19103

⁴National Association of Corrosion Engineers, NACE International, Box 217430, Houston, Texas 77218-8340

⁵Society of Petroleum Engineers, P. O. Box 833836, Richardson, TX 75083-3836

3 Definitions and Abbreviations**3.1 DEFINITIONS**

The following definitions are provided to help clarify and explain use of certain terms in the context of this publication. Users should recognize that some of these terms can be used in other instances where the application or meaning may vary from the specific information provided in this publication.

3.1.1 accumulator: A pressure vessel charged with nitrogen gas and used to store hydraulic fluid under pressure for operation of blowout preventers (BOPs).

3.1.2 annular preventer: A device that can seal around any object in the wellbore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

3.1.3 articulated line: An articulated line is a choke or kill line assembled as a unit, with rigid pipe, swivel joints, and end connections, designed to accommodate specified relative movement between end terminations.

3.1.4 bell nipple (mud riser, flow nipple): A piece of pipe, with inside diameter equal to or greater than the blowout preventer bore, connected to the top of the blowout preventer or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker or pit. This pipe usually has a second side outlet for the fill-up line connection.

3.1.5 blind rams (blank, master): Rams whose ends are not intended to seal against any drill pipe or casing. The rams seal against each other to effectively close the hole.

3.1.6 blind/shear rams: Blind rams with a built-in cutting edge that will shear tubulars that may be in the hole, thus allowing the blind rams to seal the hole. Used primarily in subsea BOP systems.

3.1.7 blowout: An uncontrolled flow of well fluids and/or formation fluids from the wellbore or into lower pressured subsurface zones (underground blowout).

3.1.8 blowout preventer (BOP): A device attached to the casinghead that allows the well to be sealed to confine the well fluids in the wellbore.

3.1.9 blowout preventer (BOP) drill: A training procedure to determine that rig crews are familiar with correct operating practices to be followed in the use of blowout prevention equipment. A dry run of blowout preventive action.

3.1.10 blowout preventer (BOP) operating and control system (closing unit): The assembly of pumps, valves, lines, accumulators, and other items necessary to open and close the blowout preventer equipment.

- 3.1.11 blowout preventer (BOP) stack:** The assembly of well control equipment including preventers, spools, valves, and nipples connected to the top of the casinghead.
- 3.1.12 blowout preventer (BOP) test tool:** A tool to allow pressure testing of the BOP stack and accessory equipment by sealing the wellbore immediately below the stack.
- 3.1.13 buffer tank:** A targeted, horizontal, cylindrical tank that changes the direction of fluid flow downstream of the choke and serves as a flow director to the flare line or gas buster.
- 3.1.14 casinghead/spool:** The part of the wellhead to which the BOP stack is connected.
- 3.1.15 choke:** A device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas.
- 3.1.16 choke line valve:** The valve(s) connected to and a part of the BOP stack that controls the flow to the choke manifold.
- 3.1.17 choke manifold:** An assembly of valves, chokes, gauges, and lines used to control the rate of flow from the well when the BOPs are closed.
- 3.1.18 clamp connection:** A pressure sealing device used to join two items without using conventional bolted flange joints. The two items to be sealed are prepared with clamp hubs. These hubs are held together by a clamp containing two to four bolts.
- 3.1.19 close-assist valve:** A valve capable of automatically closing via mechanical or hydraulic means, or a combination thereof.
- 3.1.20 closing ratio:** The ratio of the wellhead pressure to the pressure required to close the BOP.
- 3.1.21 conductor pipe:** A relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the upflowing drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well. Conductor pipe is usually cemented.
- 3.1.22 control manifold:** The system of valves and piping to control the flow of hydraulic fluid to operate the various components of the BOP stack.
- 3.1.23 control panel, remote:** A panel containing a series of controls that will operate the valves on the control
- 3.1.25 diverter control system:** The assemblage of pumps, accumulator bottles, manifolds, control panels, valves, lines, etc. used to operate the diverter system.
- 3.1.26 diverter system:** The assemblage of an annular sealing device, flow control means, vent system components, and control system that facilitates closure of the upward flow path of well fluids and opening of the vent to atmosphere.
- 3.1.27 diverter vent line:** The conduit which directs the flow of gas and wellbore fluids away from the drill floor to the atmosphere.
- 3.1.28 drill floor substructure:** The foundation structure(s) on which the derrick, rotary table, drawworks, and other drilling equipment are supported.
- 3.1.29 drill pipe safety valve:** An essentially full-opening valve located on the rig floor with threads to match the drill pipe connections in use. This valve is used to close off the drill pipe to prevent flow.
- 3.1.30 drilling fluid return line:** Refer to *flow line*.
- 3.1.31 drilling fluid weight recorder:** An instrument in the drilling fluid system that continuously measures drilling fluid density.
- 3.1.32 drilling spool:** A connection component with ends either flanged or hubbed. It must have an internal diameter at least equal to the bore of the BOP and can have smaller side outlets for connecting auxiliary lines.
- 3.1.33 drilling string float:** A check valve in the drill string that will allow fluid to be pumped into the well but will prevent flow from the well through the drill pipe.
- 3.1.34 drive pipe:** A relatively short string of large diameter pipe driven or forced into the ground to function as conductor pipe.
- 3.1.35 fill-up line:** A line usually connected into the bell nipple above the BOPs to facilitate adding drilling fluid to the hole while pulling out of the hole to compensate for the metal volume displacement of the drill string being pulled.
- 3.1.36 flame retardant:** Any item of material or equipment that is specifically designed and built to withstand exposure at a given level of temperature for a given period of time.
- 3.1.37 flex/ball joint:** A device installed directly above the subsea BOP stack and below the telescopic riser joint to

3.1.39 full bore valve: A valve with unobstructed flow area dimension equal to or greater than the nominal connection size.

3.1.40 function test: Closing and opening (cycling) equipment to verify operability.

3.1.41 gate valve: A valve that employs a sliding gate to open or close the flow passage. The valve may or may not be full opening.

3.1.42 hang off: An action whereby that portion of the drill string below the ram BOP remains in the hole supported by a tool joint resting atop the closed pipe rams.

3.1.43 hydrogen sulfide (H₂S): A highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon bearing formations.

3.1.44 hydrogen sulfide equipment service: Equipment designed to resist corrosion and hydrogen embrittlement caused by exposure to hydrogen sulfide (H₂S).

3.1.45 hydrostatic head: The pressure that exists at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.46 insert type (packer) diverter: A diverter assembly whose body does not require disassembly to utilize interchangeable packing elements that are specifically sized for the pipe diameter in use in the hole.

3.1.47 inside blowout preventer (BOP): A device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow.

3.1.48 integral valve: A valve embodied in the diverter unit that operates integrally with the annular sealing device.

3.1.49 interlock: An arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another function. Also referred to as *sequencing*.

3.1.50 kelly cock: A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

3.1.51 kelly valve, lower: An essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the drill pipe tool joint outside diameter. This valve can be closed under pressure to remove the kelly and can be stripped into the hole for snubbing operations.

Note: Some lower kelly valve models are not designed to withstand external pressure encountered in stripping operations.

3.1.52 kick: Influx of formation liquids or gas that results in an increase in pit volume. Without corrective measure, this condition can result in a blowout.

3.1.53 kill line: A high pressure line between the pumps and some point below a BOP. This line allows fluids to be pumped into the well or annulus with the BOPs closed.

3.1.54 lost returns: Loss of drilling fluid into the formation resulting in a decrease in pit volume.

3.1.55 minimum internal yield pressure: The lowest pressure at which permanent deformation will occur.

3.1.56 opening ratio: The ratio of the well pressure to the pressure required to open the BOP.

3.1.57 overburden: The pressure on a formation due to the weight of the earth material above that formation. For practical purposes, this pressure can be estimated at 1 psi/ft of depth.

3.1.58 packoff or stripper: A device with an elastomer packing element that depends on pressure below the packing to effect a seal in the annulus. This device is used primarily to run or pull pipe under low or moderate pressures. This device is not normally considered dependable for service under high differential pressures.

3.1.59 pipe rams: Rams whose ends are contoured to seal around pipe to close the annular space. Unless special rams accommodating several pipe sizes are used, separate rams are necessary for each size (outside diameter) pipe in use.

3.1.60 pit volume indicator: A device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.61 pit volume totalizer: A device that combines all of the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.62 plug valve: A valve whose mechanism consists of a plug with a hole through it on the same axis as the direction of fluid flow. Turning the plug 90 degrees opens or closes the valve. The valve may or may not be full-opening.

3.1.63 pressure gradient, normal: The subsurface pressure proportional to depth, which is roughly equal to the hydrostatic pressure of a column of salt water (0.465 psi/ft).

3.1.64 pressure regulator: A control system component which permits attenuation of control system supply pressure to a satisfactory pressure level to operate components downstream.

3.1.65 rated working pressure: The maximum internal pressure that equipment is designed to contain or control.

Note: Rated working pressure should not be confused with test pressure.

3.1.66 relief well: An offset well drilled to intersect the subsurface formation to combat a blowout.

3.1.67 rotating head: A rotating pressure-sealing device used in drilling operations utilizing air, gas, foam, or any other drilling fluid whose hydrostatic pressure is less than the formation pressure.

3.1.68 salt water flow: An influx of formation salt water into the wellbore.

3.1.69 shale shaker: Any of several mechanical devices utilizing screens that remove cuttings and other large solids from drilling fluid.

3.1.70 shear rams: Refer to blind/shear rams.

3.1.71 shuttle valve: A slide valve with two inlets and one outlet that prevents movement of hydraulic fluid between two redundant subsea control pods.

3.1.72 space out: The procedure conducted to position a predetermined length of drill pipe above the rotary table so that a tool joint is located above the subsea BOP rams on which drill pipe is to be suspended (hung off) and so that no tool joint is opposite a set of BOP rams after drill pipe is hung off.

3.1.73 swabbing: The lowering of the hydrostatic pressure in the hole due to upward movement of pipe and/or tools.

3.1.74 trip gas: An accumulation of gas which enters the hole while a trip is made.

3.1.75 umbilical: A control hose bundle or electrical cable that runs from the reel on the surface to the subsea control pod on the LMRP.

3.1.76 vent line: The conduit that directs the flow of diverted wellbore fluids away from the drill floor to the atmosphere.

3.1.77 wireline preventers: Preventers installed on top of the well or drill string as a precautionary measure while running wireline into the hole. The preventer packing will close around the wireline to prevent flow.

3.2 ACRONYMS AND ABBREVIATIONS

The following acronyms and abbreviations are used in this publication:

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
BOP	Blowout Preventer
cm	Centimeter
H ₂ S	Hydrogen Sulfide
IADC	International Association of Drilling Contractors
ID	Inside Diameter
IOM	Installation, Operation, and Maintenance

LMRP	Lower Marine Riser Package
m	meter
m ³	cubic meter
MPa	Megapascal
MUX	Multiplex Systems
NACE	National Association of Corrosion Engineers
OD	Outside Diameter
psi	Pounds per square inch
PGB	Permanent Guide Base
PTFE	Polytetrafluoroethylene
PQR	Procedure Qualification
SSC	Sulfide Stress Cracking
WPS	Weld Procedure Specification

4 Diverter Systems—Surface BOP Installations

4.1 PURPOSE

A diverter system is often used during top-hole drilling. A diverter is not designed to shut in or halt flow, but rather permits routing of the flow away from the rig. The diverter is used to protect the personnel and equipment by re-routing the flow of shallow gas and wellbore fluids emanating from the well to a remote vent line. The system deals with the potentially hazardous flows that can be experienced prior to setting the casing string on which the BOP stack and choke manifold will be installed. The system is designed to pack-off around the kelly, drill string, or casing to divert flow in a safe direction. Diverters having annular packing units can also close on open hole. Valves in the system direct the well flow when the diverter is actuated. The function of the valves may be integral to the diverter unit.

4.2 EQUIPMENT AND INSTALLATION GUIDELINES

4.2.1 Refer to API Recommended Practice 64 for information on diverter systems.

4.2.2 The diverter system consists of a low pressure diverter or an annular preventer of sufficient internal bore to pass the bit required for subsequent drilling. Vent line(s) of adequate size [6 inches (15.24 cm) or larger] are attached to outlets below the diverter and extended to a location(s) sufficiently distant from the well to permit safe venting.

4.2.3 Conventional annular BOPs, insert-type diverters, or rotating heads can be used as diverters. The rated working pressure of the diverter and vent line(s) are designed and sized to permit diverting of well fluids while minimizing wellbore back pressure. Vent lines are typically 10 inches (25.4 cm) or larger ID for offshore and 6 inches (15.24 cm) or larger ID for onshore operations.

4.2.4 If the diverter system incorporates a valve(s) on the vent line(s) (refer to API Recommended Practice 64), this valve(s) should be full opening and full bore (have at least the same opening as the line in which they are installed). The system should be hydraulically controlled such that at least one vent line valve is in the open position before the diverter packer closes.

4.2.5 The diverter and all valves should be function tested when installed and at appropriate times during operations to determine that the system will function properly. Refer to 17.4 and Tables 1 and 2 for further guidance on diverter testing.

CAUTION: Fluid should be pumped through the diverter and each diverter vent line at appropriate times during operations to ascertain the line(s) is not plugged (refer to API Recommended Practice 64). Inspection and cleanout ports should be provided at all low points in the system. Drains and/or heat tracings may be required in colder climates.

4.2.6 Accumulator capacity for diverter systems should be sized in accordance with API Recommended Practice 64.

4.2.7 Consideration should be given to the low temperature properties of materials used for facilities to be exposed to unusually low temperatures.

5 Diverter Systems—Subsea BOP Installations

5.1 PURPOSE

The diverter is used to protect the personnel and equipment by rerouting the flow of shallow gas and wellbore fluids emanating from the well through an overboard vent line. A diverter is not designed to shut in or halt flow, but rather permits routing of the flow away from the rig. The system deals with the potentially hazardous flows which may be experienced prior to setting the casing string on which the BOP stack and choke manifold will be installed. The system is designed to pack-off around the kelly, drill string, or casing to divert flow in a safe direction. Diverters having annular packing units can also close on open hole. Valves in the system direct the well flow when the diverter is actuated. The function of the valves may be integral to the diverter unit.

5.2 EQUIPMENT AND INSTALLATION GUIDELINES

5.2.1 Refer to API Recommended Practice 64, for information on diverter systems.

5.2.2 Diverter systems on floating rigs are typically installed below the rotary table and are at the upper end of the marine riser system. There are instances where the diverter unit is installed subsea.

5.2.3 The diverter system vent lines are usually large diameter [10 inches (25.4 cm) or larger] and designed to divert well fluids with minimal back pressure on the wellbore. Flow should be directed to the downwind side of the vessel. Any valves in the diverter vent lines should be full opening and full bore (have at least the same opening as the line in which installed), and be either automatic or selectively sequenced such that the wellbore flow cannot at any time be completely closed in.

5.2.4 The diverter and all valves should be function tested when installed and at appropriate times during operations to determine that the system will function properly. Refer to 18.4 and Tables 3 and 4 for further guidance on diverter testing.

CAUTION: Fluid should be pumped through the diverter and each diverter vent line at appropriate times during operations to ascertain the line(s) is not plugged. Inspection and cleanout ports should be provided at all low points in the system. Drains and/or heat tracings may be required in colder climates.

5.2.5 Accumulator capacity for diverter systems should be sized in accordance with API Recommended Practice 64.

5.2.6 Consideration should be given to the low temperature properties of materials used for facilities to be exposed to unusually low temperatures.

6 Surface BOP Stack Arrangements

6.1 EXAMPLE BOP STACK ARRANGEMENTS

6.1.1 Example arrangements for BOP equipment are based on rated working pressures. Example stack arrangements shown in Figures 1 to 3 should prove adequate in normal environments, for rated working pressures of 2K, 3K, 5K, 10K, 15K, and 20K. Arrangements other than those illustrated may be equally adequate in meeting well requirements and promoting safety and efficiency.

	Rated Working Pressure
2K	2,000 psi (13.8 MPa)
3K	3,000 psi (20.7 MPa)
5K	5,000 psi (34.5 MPa)
10K	10,000 psi (69.0 MPa)
15K	15,000 psi (103.5 MPa)
20K	20,000 psi (138.0 MPa)

Note: 1 psi = 0.006894757 MPa.

6.2 STACK COMPONENT CODES

Every installed ram BOP should have, as a minimum, a working pressure equal to the maximum anticipated surface pressure to be encountered. The recommended component codes for designation of BOP stack arrangements are as follows:

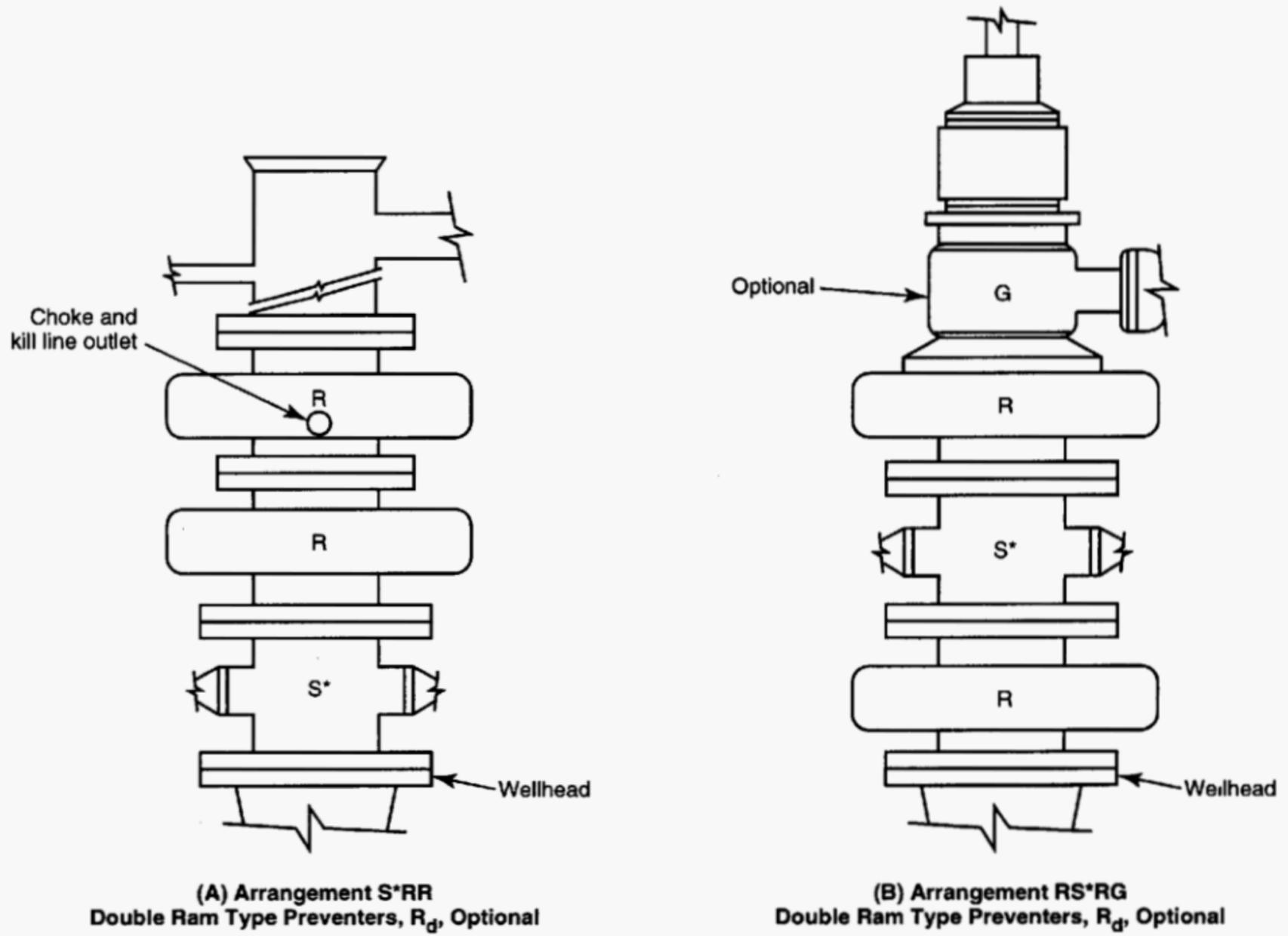
- G = rotating head.
- A = annular type BOP.
- R = single ram type BOP with one set of rams, either blank or for pipe, as operator prefers.
- R_d = double ram type BOP with two sets of rams, positioned in accordance with operator's choice.
- R_t = triple ram type BOP with three sets of rams, positioned in accordance with operator's choice.
- S = drilling spool with side outlet connection for choke and kill lines.
- K = 1000 psi rated working pressure.

BOP components are typically described upward from the uppermost piece of permanent wellhead equipment, or from

6.6 DRILLING SPOOLS

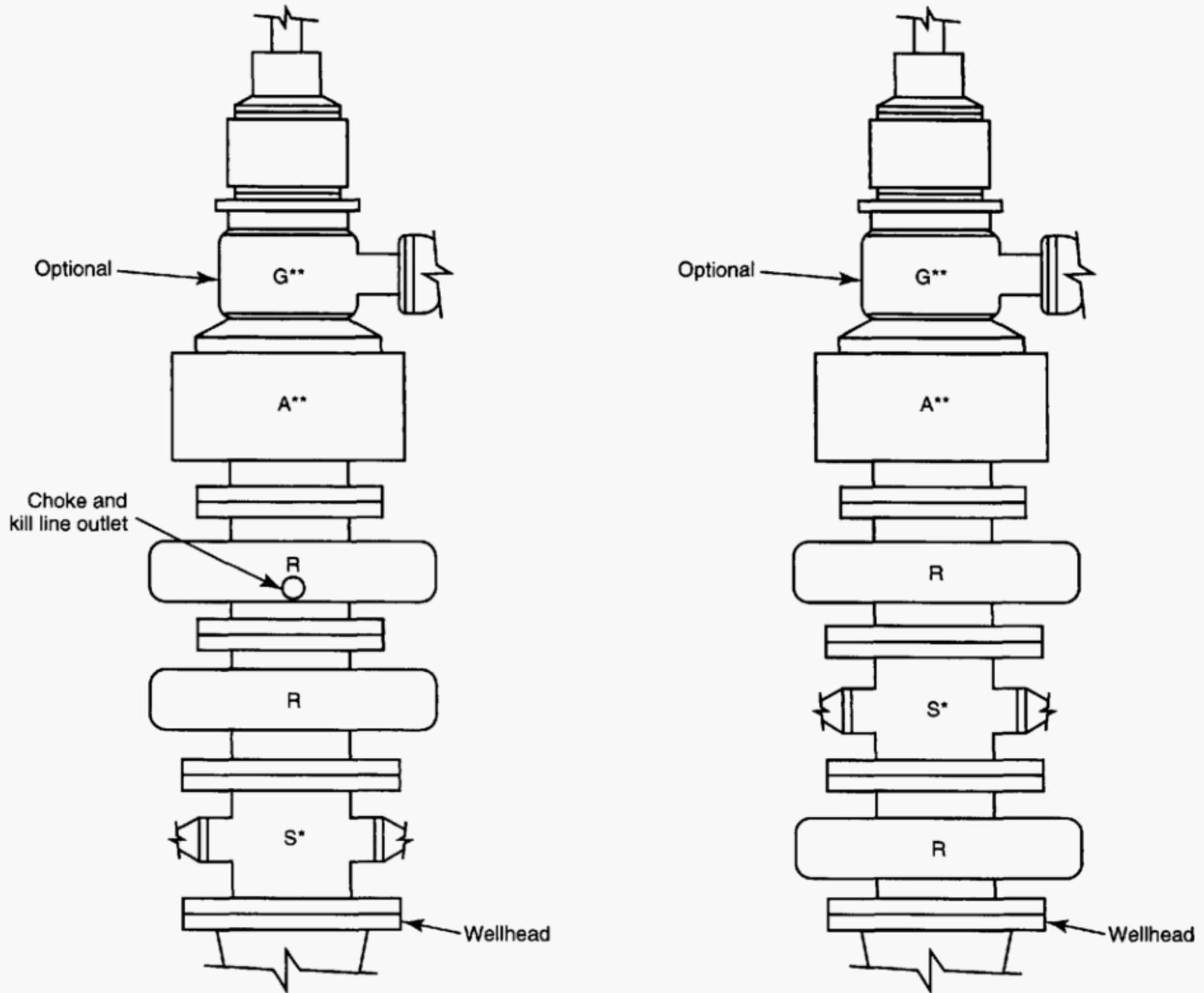
Choke and kill lines may be connected either to side outlets of the BOPs, or to a drilling spool installed below at least one BOP capable of closing on pipe. Utilization of the BOP side outlets reduces the number of stack connections and overall BOP stack height. However, a drilling spool is used to provide stack outlets (to localize possible erosion in the less expensive spool) and to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations.

6.6.1 Drilling spools for BOP stacks should meet the following minimum qualifications:



*Drilling spool and its location in the stack arrangement is optional.

Figure 1—Example Arrangements for 2K Rated Working Pressure Service—
Surface BOP Installations



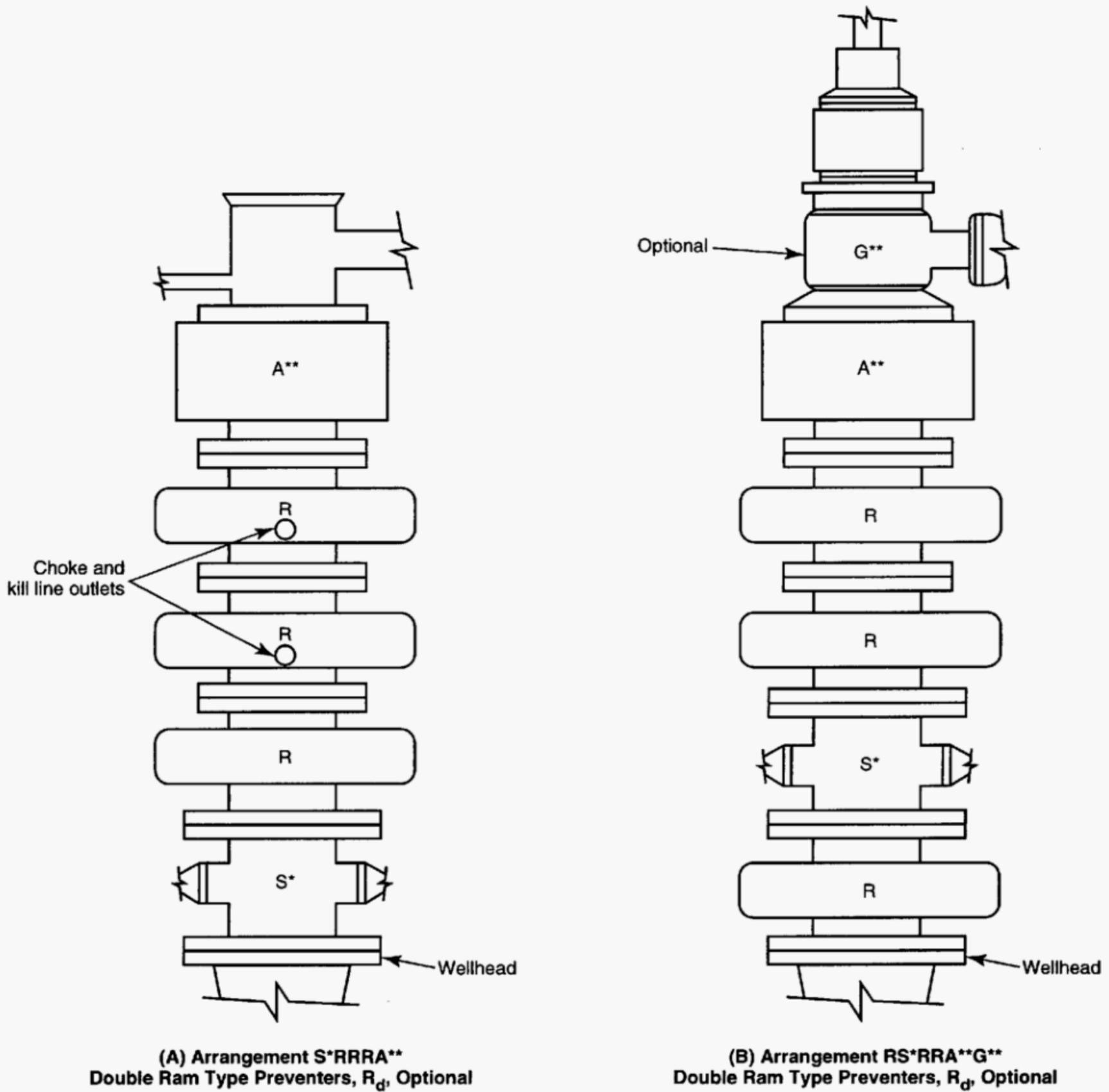
(A) Arrangement S*RRA**G**
Double Ram Type Preventers, R_d, Optional

(B) Arrangement RS*RA**G**

*Drilling spool and its location in the stack arrangement is optional.

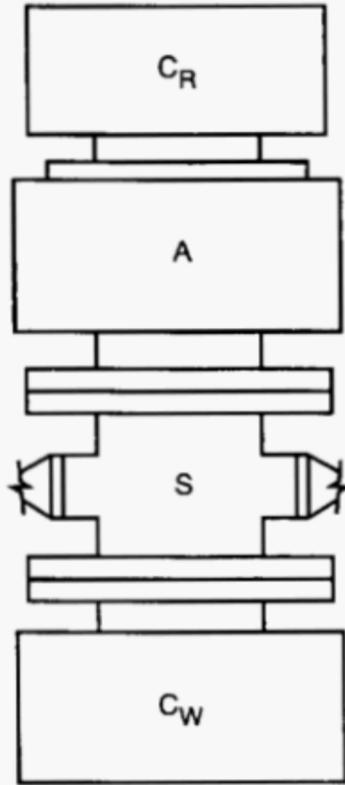
**Annular preventer, A, and rotating head, G, can be of a lower working pressure rating and can be installed on any arrangement.

Figure 2—Example Arrangements for 3K and 5K Rated Working Pressure Service—
Surface BOP Installations

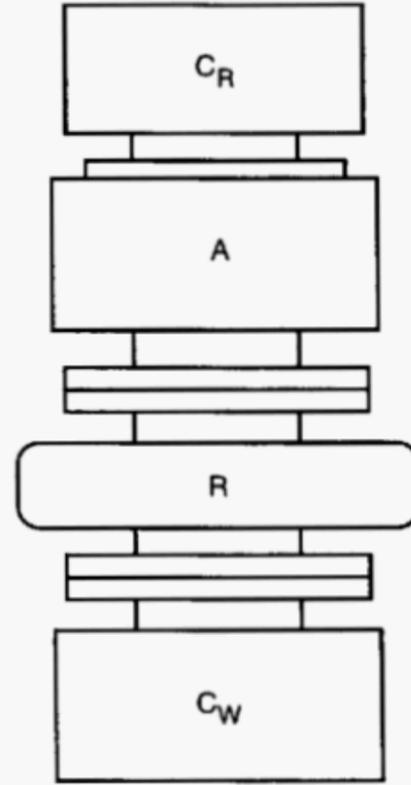


*Drilling spool and its location in the stack arrangement is optional.
 **Annular preventer, A, and rotating head, G, can be of a lower working pressure rating and can be installed on any arrangement.

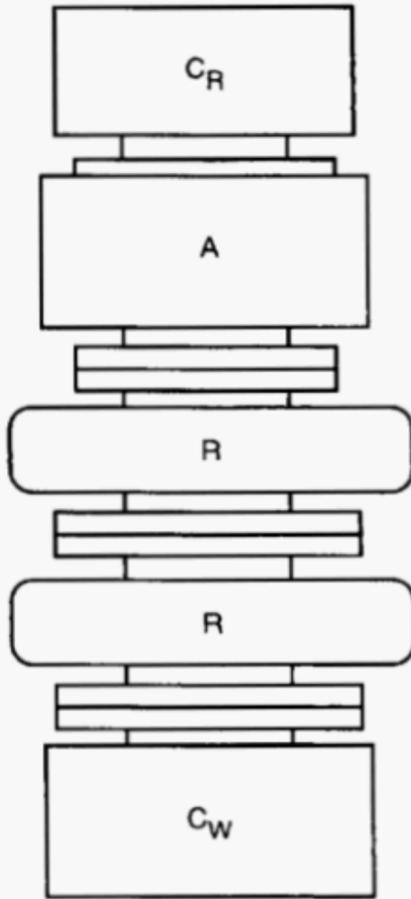
Figure 3—Example Arrangements for 10K, 15K, and 20K Working Pressure Service—Surface BOP Installations



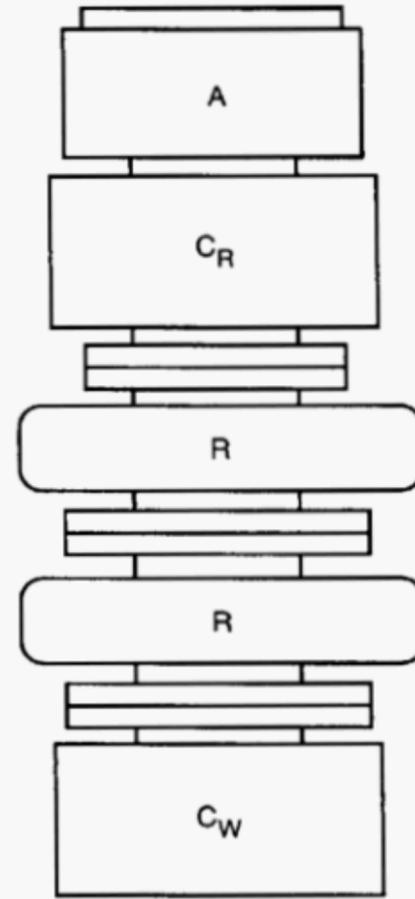
(A) Arrangement $C_W S A C_R$
(2K Rated Working Pressure Only)



(B) Arrangement $C_W R A C_R$



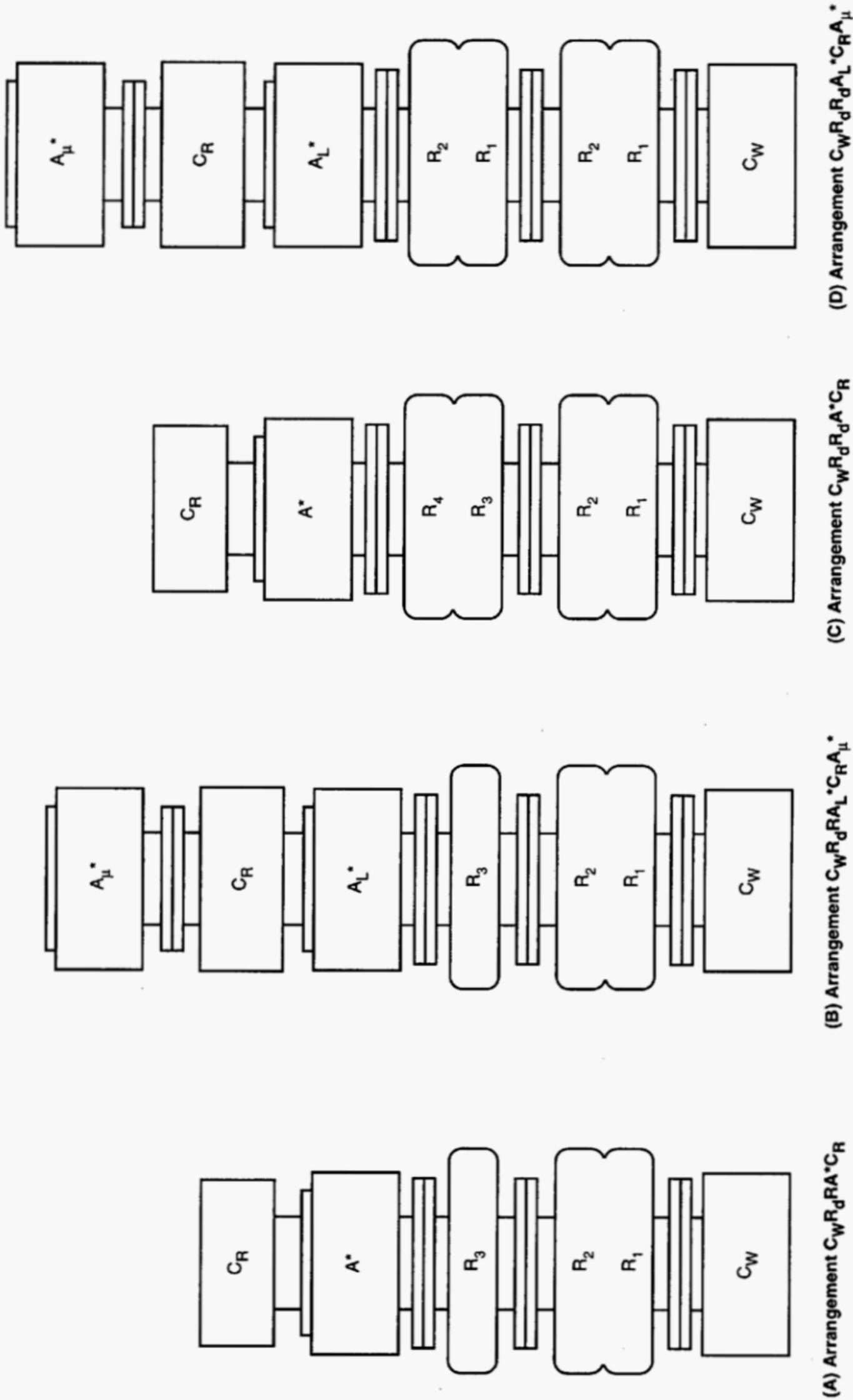
(C) Arrangement $C_W R R A C_R$
Double Ram Type Preventers, R_D , Optional



(D) Arrangement $C_W R R C_R A$
Double Ram Type Preventers, R_D , Optional

Figure 4—Example Arrangements for 2K and 3K Rated Working Pressure Service—
Subsea BOP Installations

(Refer to Figure 14 for examples of kill and choke line outlets.)



*Annular preventer, A, can be of a lower rated working pressure and can be installed on any arrangement.

Figure 5—Example Arrangements for 5K, 10K, and 15K Rated Working Pressure Service—
Subsea BOP Installations

7.2 STACK COMPONENT CODES

Every installed ram BOP should have, as a minimum, a working pressure equal to the maximum anticipated surface pressure to be encountered. The recommended component codes for designation of BOP stack arrangements are as follows:

- A_U = annular type BOP—upper.
- A_L = annular type BOP—lower.
- R = single ram type BOP with one set of rams, either blank or for pipe, as operator prefers.

potential well control events. Specifically for floating operations, the arrangement should provide a means to:

- a. Close in on the drill string and on casing or liner and allow circulation.
- b. Close and seal on open hole and allow volumetric well control operations.
- c. Strip the drill string using the annular BOP(s).
- d. Hang off the drill pipe on a ram BOP and control the wellbore.
- e. Shear logging cable or the drill pipe and seal the wellbore.
- f. Disconnect the riser from the BOP stack.

least one BOP capable of closing on pipe. Utilization of the BOP side outlets reduces the number of stack connections and overall BOP stack height. Typically, drilling spools are not installed on subsea BOPs; however, a drilling spool can be used to provide stack outlets (to localize possible erosion in the less expensive spool) and to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations.

7.6.2 Drilling spools for BOP stacks should meet the following minimum specifications:

- a. 3K and 5K arrangements should have two side outlets no smaller than a 2-inch (5.08 cm) nominal diameter and be flanged, studded, or hubbed. 10K, 15K, and 20K arrangements should have two side outlets, one 3-inch (7.62 cm) and one 2-inch (5.08 cm) nominal diameter as a minimum, and be flanged, studded, or hubbed.
- b. Have a vertical bore diameter the same internal diameter as the mating BOPs and at least equal to the maximum bore of the uppermost casing/tubing head.
- c. Have a rated working pressure equal to the rated working pressure of the installed ram BOP.

8 Choke Manifolds and Choke Lines—Surface BOP Installations

8.1 GENERAL

The choke manifold consists of high pressure pipe, fittings, flanges, valves, and manual and/or hydraulic operated adjustable chokes. This manifold may bleed off wellbore pressure at a controlled rate or may stop fluid flow from the wellbore completely, as required.

8.2 INSTALLATION GUIDELINES—CHOKE MANIFOLD

Recommended practices for installation of choke manifolds for surface installations include:

- a. Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) should have

lines together. When buffer tanks are employed, provision should be made to isolate a failure or malfunction.

e. All choke manifold valves should be full bore. Two valves are recommended between the BOP stack and the choke manifold for installations with rated working pressures of 5,000 psi (34.5 MPa) and above. One of these two valves should be remotely controlled. During operations, all valves should be fully opened or fully closed.

f. A minimum of one remotely operated choke should be installed on 10,000 psi (69.0 MPa), 15,000 psi (103.5 MPa), and 20,000 psi (138.0 MPa) rated working pressure manifolds.

g. Choke manifold configurations should allow for re-routing of flow (in the event of eroded, plugged, or malfunctioning parts) without interrupting flow control.

h. Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures and should be protected from freezing by heating, draining, filling with appropriate fluid, or other appropriate means.

i. Pressure gauges suitable for operating pressure and drilling fluid service should be installed so that drill pipe and annulus pressures may be accurately monitored and readily observed at the station where well control operations are to be conducted.

j. The choke control station, whether at the choke manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes, etc., greatly increases well control efficiency.

k. Rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for controls and chokes. The remotely operated choke should be equipped with an emergency backup system such as a manual pump or nitrogen for use in the event rig air becomes unavailable.

8.3 INSTALLATION GUIDELINES—CHOKE LINES

8.3.1 The choke line and manifold provide a means of applying back pressure on the formation while circulating out

pipe material. However, in general, short radius pipe bends ($R/d < 10$) should be targeted in the direction of expected flow. For large radius pipe bends ($R/d > 10$), targets are generally unnecessary. Bends sometime have a wall thickness greater than the straight pipe in the choke system (such as the next higher schedule) to further compensate for the effect of erosion. 90° block *ells* and *tees* should be targeted in the direction of flow.

Where:

R = Radius of pipe bend measured at the centerline.

d = Nominal diameter of the pipe.

2. For flexible lines, consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration.

3. For articulated line assemblies, consult with the manufacturer's written specifications to determine the degree of relative movement allowable between end points.

b. Be firmly anchored to prevent excessive whip or vibration.

c. Have a bore of sufficient size to prevent excessive erosion or fluid friction:

1. Minimum recommended size for choke lines is 2-inch (5.08 cm) nominal diameter for 3K and 5K arrangements and 3-inch (7.62 cm) nominal diameter for 10K, 15K, and 20K arrangements.

2. Minimum recommended nominal inside diameter for lines downstream of the chokes should be equal to or greater than the nominal connection size of the chokes.

3. Lines downstream of the choke manifold are not normally required to contain pressure (refer to Tables 1 and 2 for testing considerations).

4. For air or gas drilling operations, minimum 4-inch (10.16 cm) nominal diameter lines are recommended.

5. The bleed line (the line that bypasses the chokes) should be at least equal in diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum back pressure. It also permits high volume bleed off of well fluids to relieve casing pressure with the preventers closed.

8.3.2 Figures 6 through 8 illustrate example choke manifolds for various working pressure service. Refinements or modifications such as additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges, and/or manifolding of vent lines may be dictated by the conditions anticipated for a particular well and the degree of protection desired. The guidelines discussed and illustrated represent examples of industry practice.

8.4 MAINTENANCE

Preventive maintenance of the choke assembly and controls should be performed regularly, checking particularly for wear and plugged or damaged lines. Frequency of maintenance will depend upon usage. Refer to Section 17 for recommendations for testing, inspection, and general maintenance of choke manifold systems.

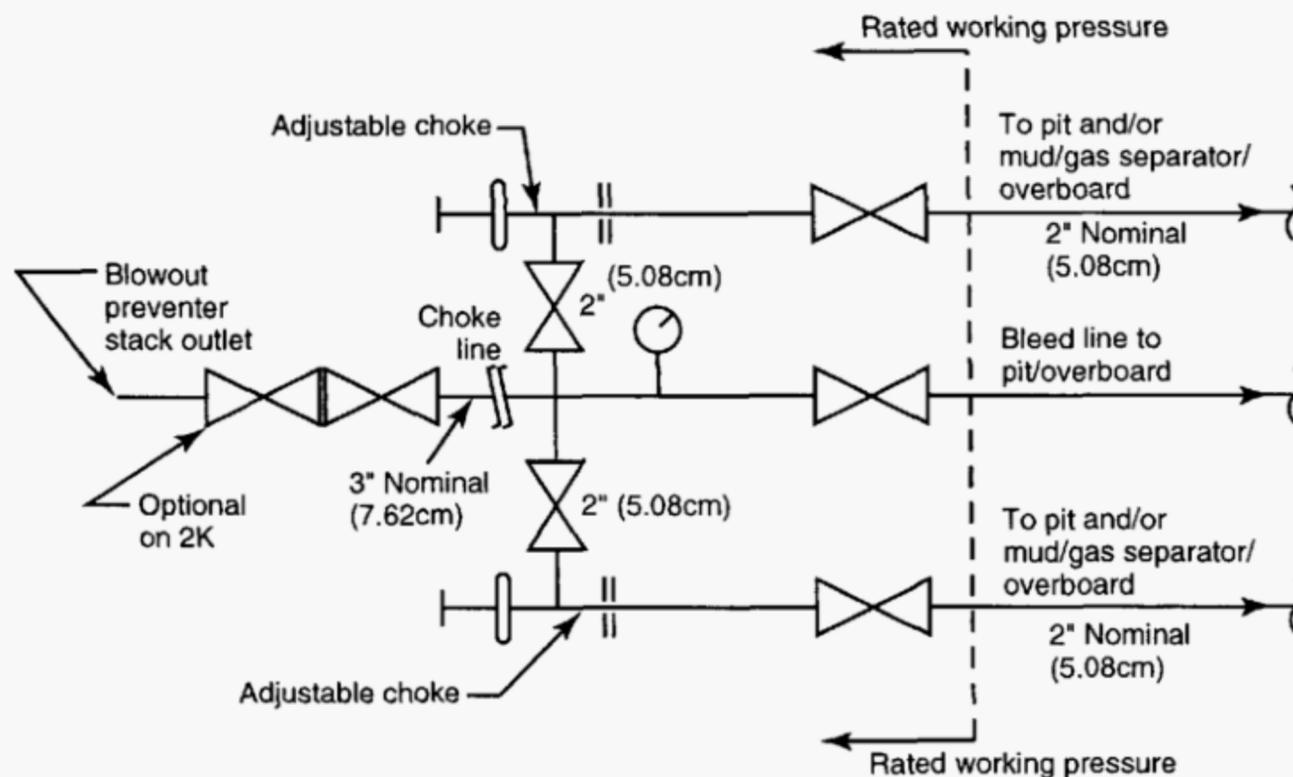


Figure 6—Example Choke Manifold Assembly for 2K and 3K Rated Working Pressure Service—Surface BOP Installations

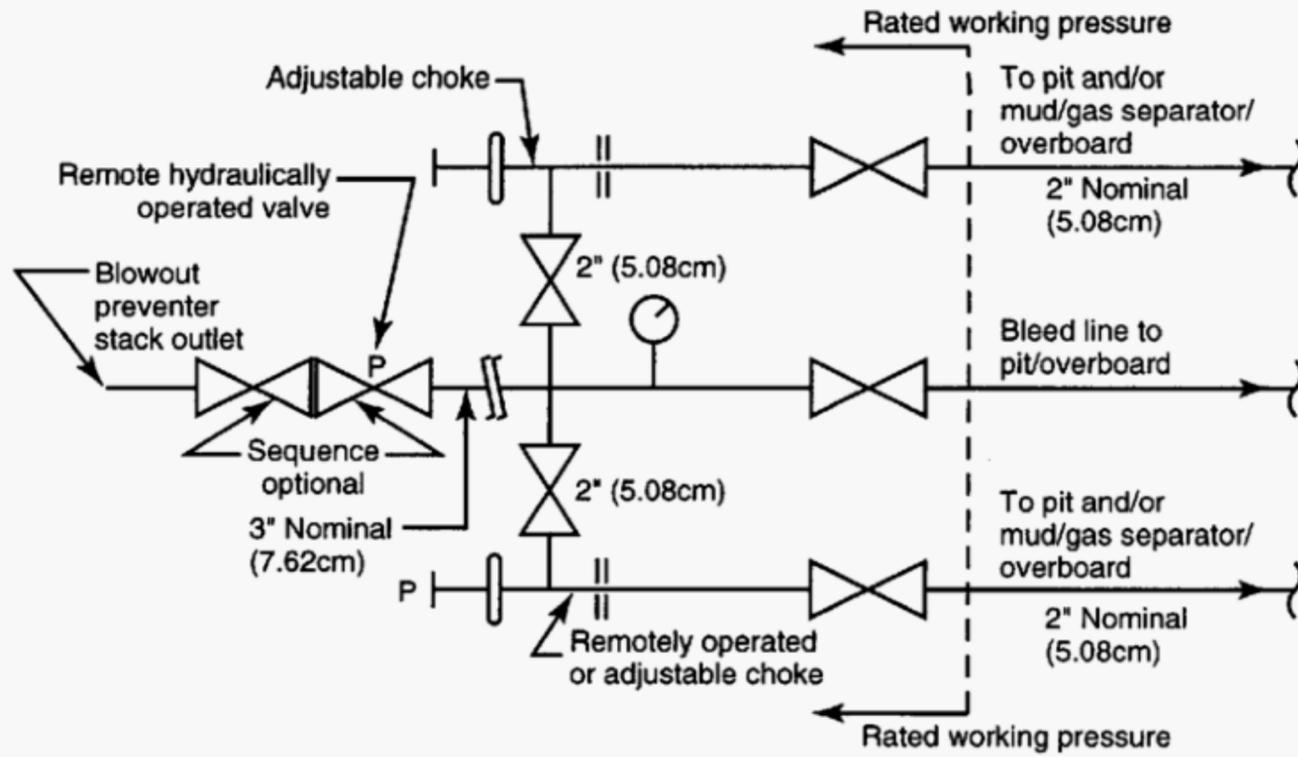


Figure 7—Example Choke Manifold Assembly for 5K Rated Working Pressure Service—Surface BOP Installations

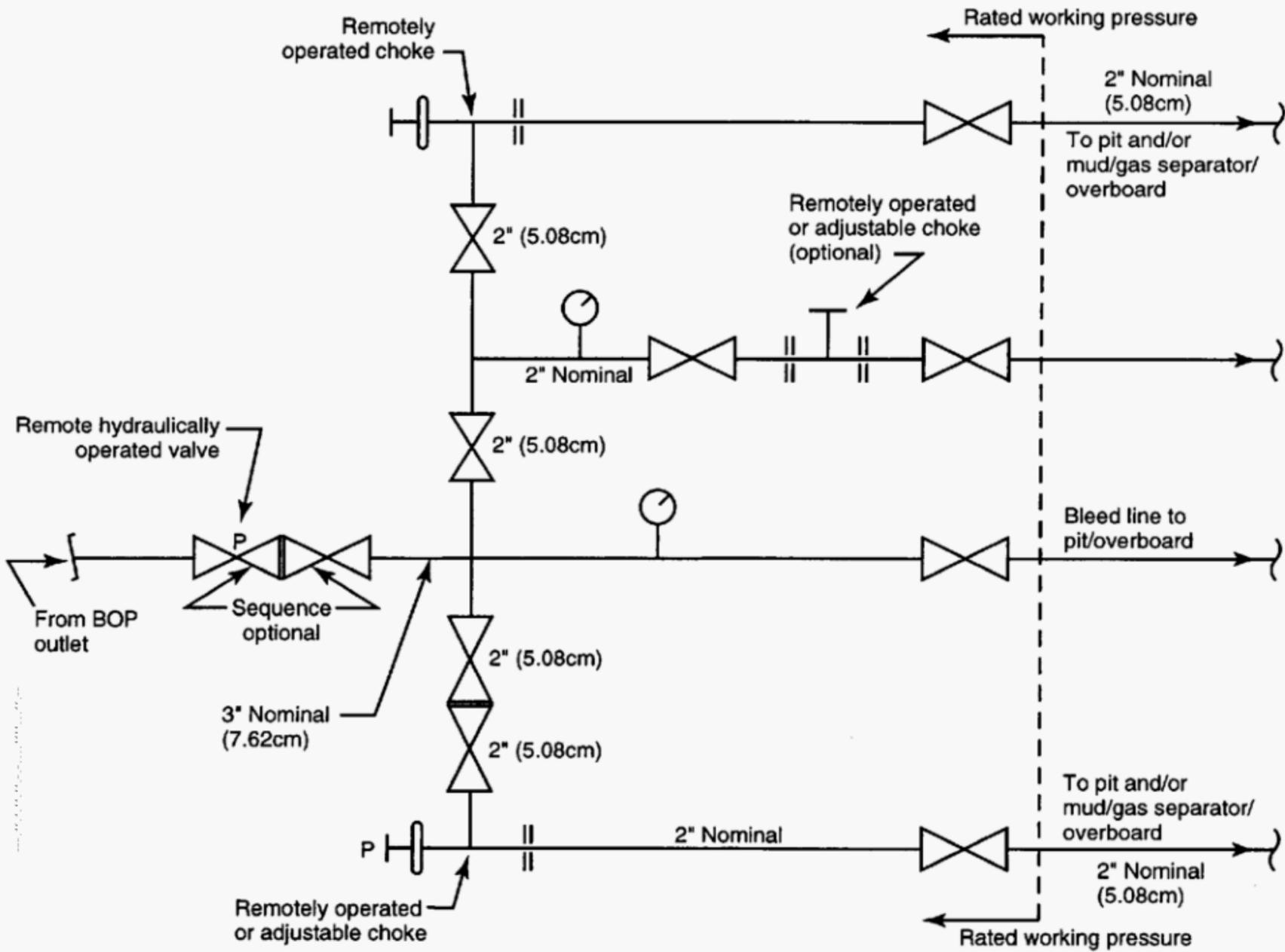


Figure 8—Example Choke Manifold Assembly for 10K, 15K, and 20K Rated Working Pressure Service—Surface BOP Installations

8.5 SPARE PARTS

An adequate supply of spare parts is important for components subject to wear or damage or whose failure seriously reduces the effectiveness of the manifold or choke line. Standardization of components is recommended to minimize the inventory required. Although the inventory will vary from rig to rig, a generalized recommended minimum spare parts list includes:

- a. One complete valve for each size installed.
- b. Two repair kits for each valve size utilized.
- c. Parts for manually adjustable chokes, such as flow tips, inserts, packing, gaskets, O-rings, disc assemblies, and wear sleeves.
- d. Parts for remotely controlled choke(s).
- e. Miscellaneous items such as hose, flexible tubing, electrical cable, pressure gauges, small control line valves, fittings, and electrical components.

9 Choke Manifolds—Subsea BOP Installations

9.1 GENERAL

The choke manifold assembly for subsea BOP installations has the same purpose as for surface installations; viz., it is used to bleed off the wellbore pressure at a controlled rate or may stop fluid flow from the wellbore completely, as required. Figure 9 is an example choke manifold assembly for a subsea installation for 5,000 psi (34.5 MPa), 10,000 psi (69.0 MPa), or 15,000 psi (103.5 MPa) rated working pressure service. This assembly differs from a surface installation in that the choke and kill lines are manifolded to permit pumping or flowing through either line. Other features include a remotely controlled adjustable choke and a manually adjustable choke system to permit control through either the choke or kill line and tie-ins to both drilling fluid and cement unit pump systems (refer to Figure 9).

9.2 INSTALLATION GUIDELINES

9.2.1 Recommended practices for installation of choke manifolds for subsea installations include:

- a. Manifold equipment subject to well and/or pump pressure (normally upstream of and including the chokes) should have a minimum working pressure at least equal to the rated working pressure of the ram BOPs in use. This equipment should be tested when installed in accordance with provisions of Section 18.
- b. For working pressures of 3,000 psi (20.7 MPa) and above, flanged, welded, hubbed, or other end connections that are in accordance with API Specification 6A, should be employed on components subjected to well pressure.

c. Although not shown in the example equipment illustrations, buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines together. When buffer tanks are employed, provision should be made to isolate a failure or malfunction.

d. The main header should be 3-inch (7.62 cm) nominal diameter or larger. All other components should be 2-inch (5.08 cm) nominal diameter or larger. The assembly should have a minimum number of turns and be securely anchored. Turns in the assembly should be targeted in both directions.

e. All choke manifold valves should be full bore. During operations, all valves should be fully opened or fully closed.

f. A minimum of one remotely operated choke should be installed on 10,000 psi (69.0 MPa), 15,000 psi (103.5 MPa), and 20,000 psi (138.0 MPa) rated working pressure manifolds.

g. Choke manifold configurations should allow for re-routing of flow (in the event of eroded, plugged, or malfunctioning parts) without interrupting flow control.

h. Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures and should be protected from freezing by heating, draining, filling with appropriate fluid, or other appropriate means.

i. Pressure gauges suitable for operating pressure and drilling fluid service should be installed so that drill pipe and annulus pressures may be accurately monitored and readily observed at the station where well control operations are to be conducted.

j. The choke control station, whether at the choke manifold or remote from the rig floor, should be as convenient as possible and should include all monitors necessary to furnish an overview of the well control situation. The ability to monitor and control from the same location such items as standpipe pressure, casing pressure, pump strokes, etc., greatly increases well control efficiency.

k. Rig air systems should be checked to assure their adequacy to provide the necessary pressure and volume requirements for controls and chokes. The remotely operated choke should be equipped with an emergency backup system such as a manual pump or nitrogen for use in the event rig air becomes unavailable.

l. Initial testing of the choke manifold assembly to the rated working pressure of the ram BOPs should be performed when the BOP stack is on the test stump (prior to running subsea). Subsequent pressure tests of the choke manifold assembly should be conducted in accordance with applicable provisions of Section 18.

m. Lines downstream of the chokes or the last valve downstream of chokes are normally not required to contain rated manifold working pressure (refer to Tables 3 and 4 for testing considerations).

n. Lines downstream of the choke manifold should be securely anchored, be of sufficient size to permit reasonable flow rates without excessive friction, and permit flow direc-

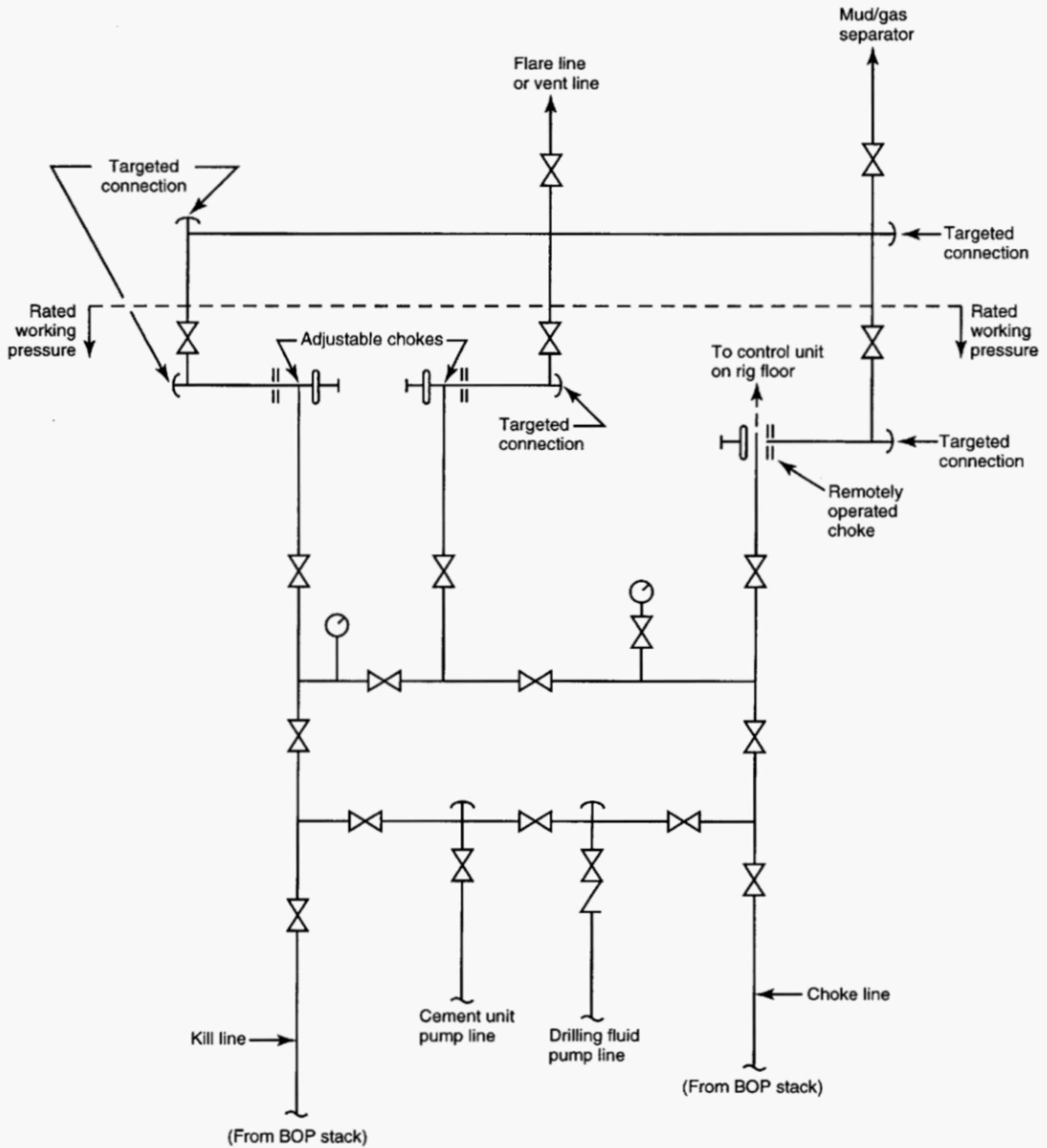


Figure 9—Example Choke and Kill Manifold for 5K, 10K, and 15K Rated Working Pressure Service—Subsea BOP Installations

tion either to a mud/gas separator, vent lines, or to production facilities or emergency storage.

9.2.2 Figure 9 illustrates an example choke manifold. Configurations of choke manifolds may vary widely as a result of space limitations, operator's policies, etc. Refinements or modifications such as additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges, and/or manifolding of bypass lines may be dictated by the conditions anticipated for a particular well and the degree of protection desired. The guidelines discussed and illustrated represent examples of industry practice.

9.3 MAINTENANCE

Preventive maintenance of the choke assembly and controls should be performed regularly, checking particularly for wear and plugged or damaged lines. Frequency of maintenance will depend upon usage. Refer to Section 18 for recommendations for testing, inspection, and general maintenance of choke systems.

9.4 SPARE PARTS

An adequate supply of spare parts is important for components subject to wear or damage or whose failure seriously reduces the effectiveness of the manifold. Standardization of components is recommended to minimize the inventory required. Although the inventory will vary from rig to rig, a generalized recommended minimum spare parts list includes:

- a. One complete valve for each size installed.
- b. Two repair kits for each valve size utilized.
- c. Parts for manually adjustable chokes, such as flow tips, inserts, packing, gaskets, O-rings, disc assemblies, and wear sleeves.
- d. Parts for the remotely controlled choke(s).
- e. Miscellaneous items such as hose, flexible tubing, electrical cable, pressure gauges, small control line valves and fittings, and electrical components.

10 Kill Lines—Surface BOP Installations

10.1 PURPOSE

10.1.1 Kill lines are an integral part of the surface equipment required for drilling well control. The kill line system provides a means of pumping into the wellbore when the normal method of circulating down through the kelly or drill pipe cannot be employed. The kill line connects the drilling fluid pumps to a side outlet on the BOP stack. The location of the kill line connection to the stack depends on the particular configuration of BOPs and spools employed; the connection should be below the ram type BOP most likely to be closed. Figures 10, 11, and 12 illustrate example kill line installations for various working pressure service.

10.1.2 On selective high-pressure, critical wells a remote kill line is commonly employed to permit use of an auxiliary high pressure pump if the rig pumps become inoperative or inaccessible. This line normally is tied into the kill line near the blowout preventer stack and extended to a site suitable for location of a pump. This site should be selected to afford maximum safety and accessibility.

10.2 INSTALLATION GUIDELINES

10.2.1 The same guidelines which govern the installation of choke manifolds and choke lines apply to kill line installations. Refer to API Specification 16C for equipment specifications for kill lines. The more important recommendations include:

- a. All lines, valves, check valves and flow fittings should have a working pressure at least equal to the rated working pressure of the ram BOPs in use. This equipment should be tested when installed in accordance with provisions of Section 17.
- b. For working pressures of 3,000 psi (20.7 MPa) and above, flanged, welded, hubbed, or other end connections that are in accordance with API Specification 6A, should be employed.
- c. Components should be of sufficient diameter to permit reasonable pumping rates without excessive friction. The minimum recommended size is 2-inch (5.08 cm) nominal diameter.
- d. Two full bore manual valves plus a check valve or two full bore valves (one of which is remotely operated) between the stack outlet and the kill line are recommended for installations with rated working pressure of 5,000 psi (34.5 MPa) or greater. Refer to Figures 11 and 12.
- e. Periodic operation, inspection, testing, and maintenance should be performed on the same schedule as employed for the BOP stack in use (refer to 17.10).
- f. All components of the kill line system should be protected from freezing by heating, draining, filling with proper fluid, or other appropriate means.
- g. Consideration should be given to the low temperature properties of the materials used in installations to be exposed to unusually low temperatures and should be protected from freezing by heating, draining, filling with appropriate fluid, or other appropriate means.
- h. Lines should be as straight as possible. When bends are required to accommodate either dimensional variation(s) on sequential rig ups or to facilitate hookup to the BOP, the largest bend radius allowable under the hookup restraints should be provided. Following is guidance for bends in different types of lines.
 1. For rigid pipe, the bend radius should be maximized. Because erosion at bends is possible during operation, consideration should be given to using flow targets at bends and on block *ells* and *tees*. The degree to which pipe bends are susceptible to erosion depends on the bend

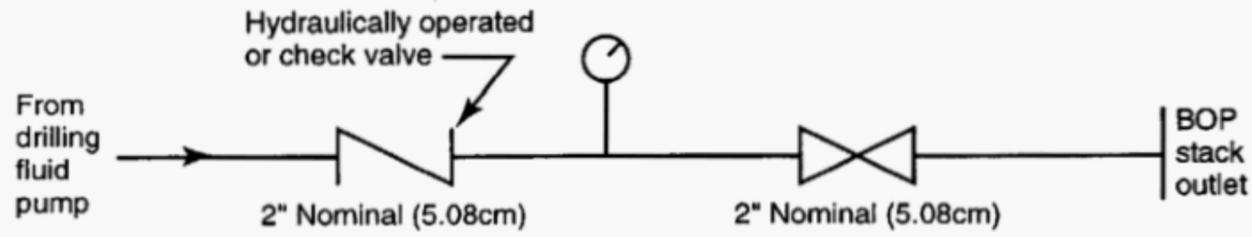


Figure 10—Example Kill Line Assembly for 2K and 3K Rated Working Pressure Service—Surface BOP Installations
(Threaded connections optional for 2K rated working pressure service.)

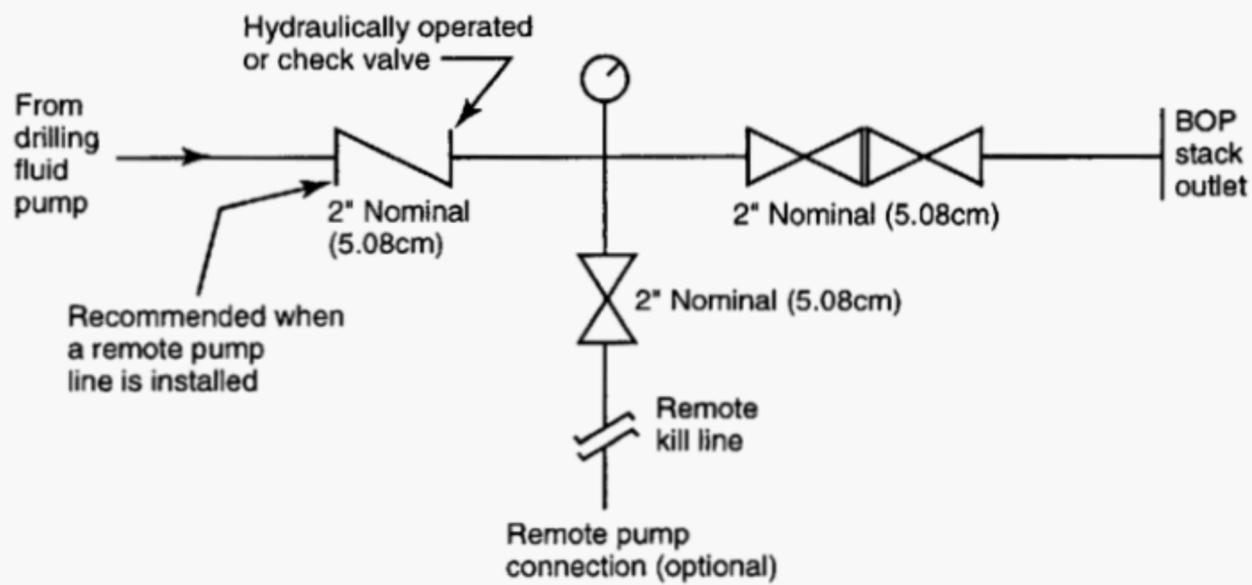


Figure 11—Example Kill Line Assembly for 5K, 10K, and 15K Rated Working Pressure Service—Surface BOP Installations

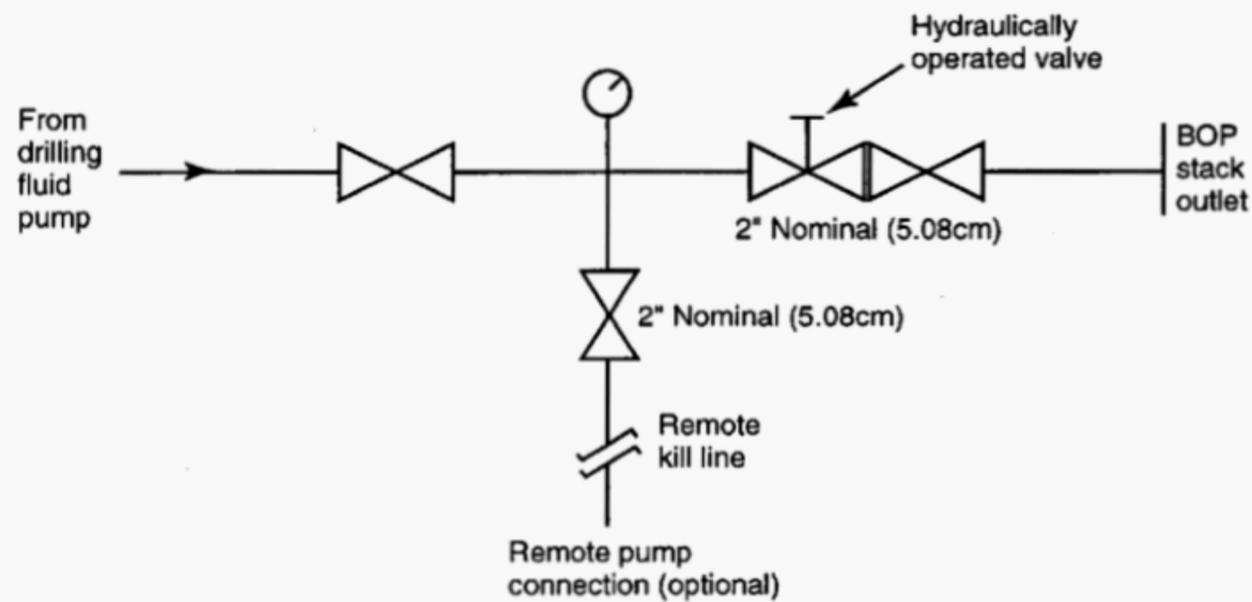


Figure 12—Example Kill Line Assembly for 5K, 10K, and 15K Rated Working Pressure Service—Surface BOP Installations

radius, flow rate, flow medium, pipe wall thickness, and pipe material. However, in general, short radius pipe bends ($R/d < 10$) should be targeted in the direction of expected flow. For large radius pipe bends ($R/d > 10$), targets are generally unnecessary. Bends sometime have a wall thickness greater than the straight pipe in the kill system (such as the next higher schedule) to further compensate for the effect of erosion. 90° block ells and tees should be targeted in the direction of flow.

Where:

R = Radius of pipe bend measured at the centerline.

d = Nominal diameter of the pipe.

2. For flexible lines, consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration.

3. For articulated line assemblies, consult the manufacturer's written specifications to determine the degree of relative movement allowable between the end points.

i. All lines should be firmly anchored to prevent excessive whip or vibration.

10.2.2 The kill line should not be used as a fill-up line during normal drilling operations.

10.3 MAINTENANCE

Preventive maintenance of the kill line assembly should be performed regularly, checking particularly for wear and plugged or damaged lines. Frequency of maintenance will depend on usage. Refer to Section 17 for recommendations on testing, inspection, and general maintenance of kill manifold systems.

10.4 SPARE PARTS

An adequate supply of spare parts is important for components subject to wear or damage or whose failure seriously reduces the effectiveness of the kill line. Standardization of components is recommended to minimize the inventory required. Although the inventory will vary from rig to rig, a generalized recommended spare parts list includes:

- a. One complete valve for each size installed.
- b. Two repair kits for each valve size utilized.
- c. Miscellaneous items such as hose, flexible tubing, electrical cable, pressure gauges, small control line valves, fittings, and electrical components.

11 Choke and Kill Lines—Subsea BOP Installations

11.1 GENERAL

For subsea BOP installations choke and kill lines are connected (through the choke manifold) to permit pumping or flowing through either line.

11.2 INSTALLATION DESCRIPTION

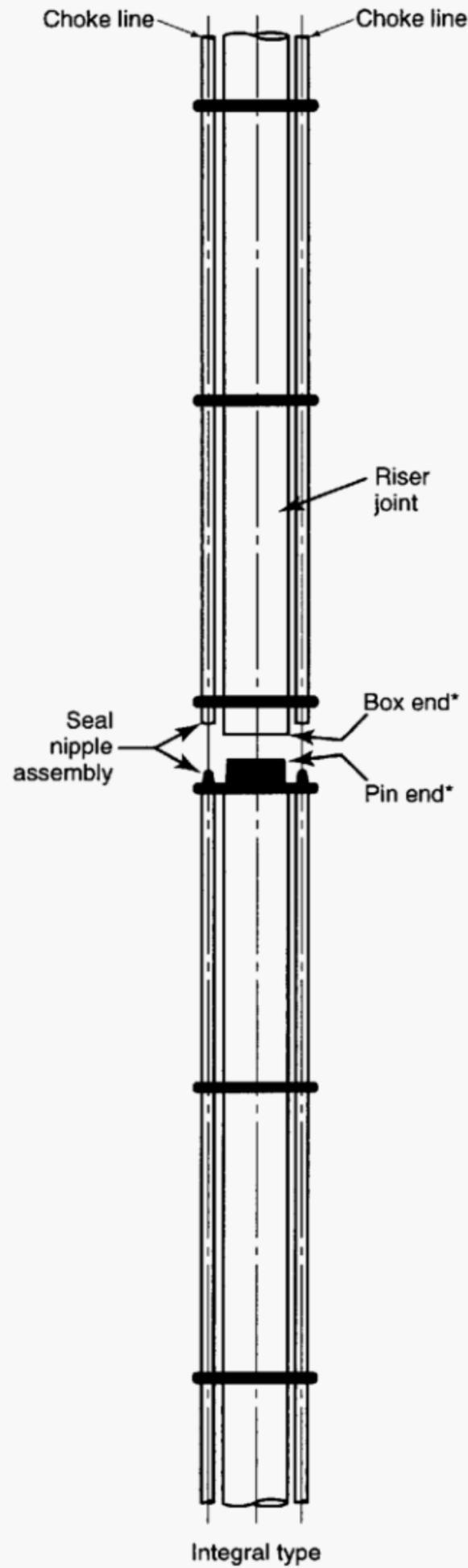
Choke and kill lines for subsea BOP installations are installed opposite one another on the exterior of the marine riser (refer to Figure 13). Choke and kill lines are normally 3-inch (7.62 cm) nominal diameter or larger. The identifying labels for the respective subsea choke and kill lines are arbitrary. Traditionally, where a circulating line is connected to an outlet below the lowermost ram BOP, this circulating line is generally designated as a kill line.

Whether or not the kill line is connected to an outlet below the lowermost ram BOP, it is preferable to have one choke line and one kill line connection above the lowermost ram BOP.

11.3 INSTALLATION GUIDELINES

Some of the more important considerations concerning subsea choke and kill lines are:

- a. Selection of choke and kill line connectors must take into consideration the ease of connect/disconnect operations and the dependability of sealing elements for those emergency situations where it is necessary to disconnect the riser from the BOP stack and then reconnect again prior to resuming normal operations.
- b. Connector pressure sealing elements should be inspected, changed as required, and tested before being placed in service. Periodic pressure testing is recommended during installation. Pressure ratings of all lines and sealing elements should equal or exceed the rated working pressure of the ram BOPs.
- c. Subsea choke/kill lines are connected to their counterpart(s) on adjoining riser joints by box-and-pin, stab-in couplings. The box contains an elastomeric radial seal that expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized. The stab-in couplings also facilitate fast makeup while deploying the marine riser.
- d. Each BOP outlet connected to the choke or kill line should have two full-opening valves adjacent to the preventers. These valves are hydraulically operated pressure assist open and spring close. Spring closure can also be assisted with hydraulic pressure. Periodic pumping through the valves is necessary since they are normally closed and may become plugged if not occasionally flushed.



*May be reversed.

Figure 13—Example Riser Mounted Kill and Choke Lines for Subsea BOP Installations

e. Location of the choke and kill line openings on the BOP stack depends on the particular configuration of the preventers and the operator's preferred flexibility for well control operations. Example arrangements are shown in Figure 14. Other arrangements may be equally adequate to meet well control requirements. Refer to 7.3.1 for guidance on arrangement considerations.

f. Flexible connections required for choke and kill lines, both at the top and bottom of the marine riser, should have a pressure rating equaling or exceeding the rated working pressure of the ram BOPs. Figures 15 and 16 illustrate example flexible choke and kill connections for subsea BOP installations.

g. The flexible choke and kill line manufacturer's guidelines should be consulted to determine/verify moon pool choke and kill line operating parameters.

h. It is important to consult the flexible choke/kill line manufacturer's guidelines for proper length determination and proper routing to ensure nonentrapment of pods and safe operating configuration which will allow full-designed deflection of the flex/ball joint. The flexible line manufacturer should be consulted prior to any modifications to the lower marine riser package to ensure subsequent safe working conditions for the flexible lines.

i. All choke and kill lines should be as straight as possible. When bends are required to facilitate hook-up provide the largest practical bend radius. Following is guidance for bends in different types of lines.

1. For rigid lines, because erosion at bends is possible during operation, consideration should be given to using erosion resistant flow targets at bends and on block ells and tees. The degree to which pipe bends are susceptible to erosion depends on the bend radius, flow rate, flow medium, pipe wall thickness, and pipe material. However, in general, short radius pipe bends ($R/d < 10$) should be targeted in the direction of expected flow. For large radius pipe bends ($R/d > 10$), targets are generally unnecessary. Bends sometime have a wall thickness greater than the straight pipe in the choke system (such as the next higher schedule) to further compensate for the effect of erosion. 90° block ells and tees should be targeted in the direction of flow.

Where:

R = Radius of pipe bend measured at the centerline.
 d = Nominal diameter of the pipe.

2. For flexible lines, consult the manufacturer's guidelines on working minimum bend radius to ensure proper length determination and safe working configuration.

3. For articulated line assemblies, consult the manufacturer's written specifications to determine the degree of relative movement allowed between end points.

j. All lines should be firmly anchored to prevent excessive whip or vibration.

k. All lines and fittings should have a bore of sufficient size to prevent excessive erosion or fluid friction:

1. Minimum recommended nominal inside diameter for lines downstream of the chokes is the nominal connection size of the chokes.

2. Lines downstream of the choke manifold are not normally required to contain pressure (refer to Tables 3 and 4 for testing considerations).

3. The bleed line (the line that bypasses the chokes) should be at least equal in diameter to the choke line. This line allows circulation of the well with the preventers closed while maintaining a minimum back pressure. It also permits high volume bleed off of well fluids to relieve casing pressure with the preventers closed.

11.4 MAINTENANCE

Preventive maintenance of the choke and kill line assemblies should be performed regularly, checking particularly for wear and plugged or damaged lines. Frequency of maintenance will depend upon usage. Refer to Section 18 for recommendations for testing, inspection, and general maintenance of choke and kill line systems.

11.5 SPARE PARTS

An adequate supply of spare parts is important for components subject to wear or damage or whose failure seriously reduces the effectiveness of the system. Standardization of components is recommended to minimize the inventory required. Although the inventory will vary from rig to rig, a generalized recommended spare parts list includes:

- a. One complete valve for each size installed.
- b. Two repair kits for each valve size utilized.
- c. Miscellaneous items such as hose, flexible tubing, electrical cable, pressure gauges, small control line valves, fittings, and electrical components.

12 Control Systems for Surface BOP Stacks

12.1 GENERAL

BOP control systems for surface installations (land rigs, offshore jackups, and platforms) normally supply hydraulic power fluid in a closed loop circuit as the actuating medium. The elements of the BOP control system normally include:

- a. Storage (reservoir) equipment for supplying ample control fluid to the pumping system.
- b. Pumping systems for pressurizing the control fluid.

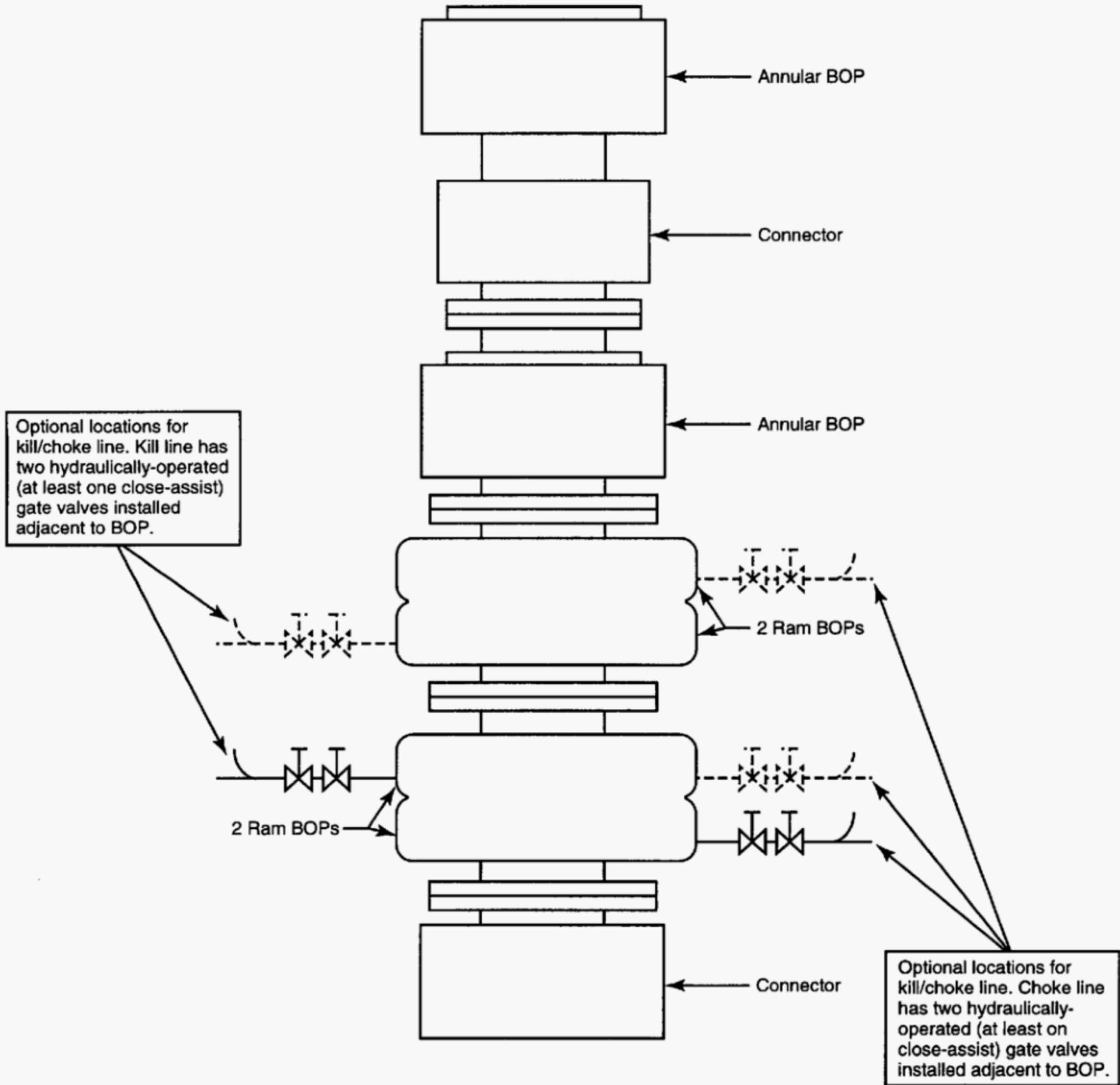


Figure 14—Example Subsea BOP Stack Illustrating Optional Locations for Kill/Choke Lines

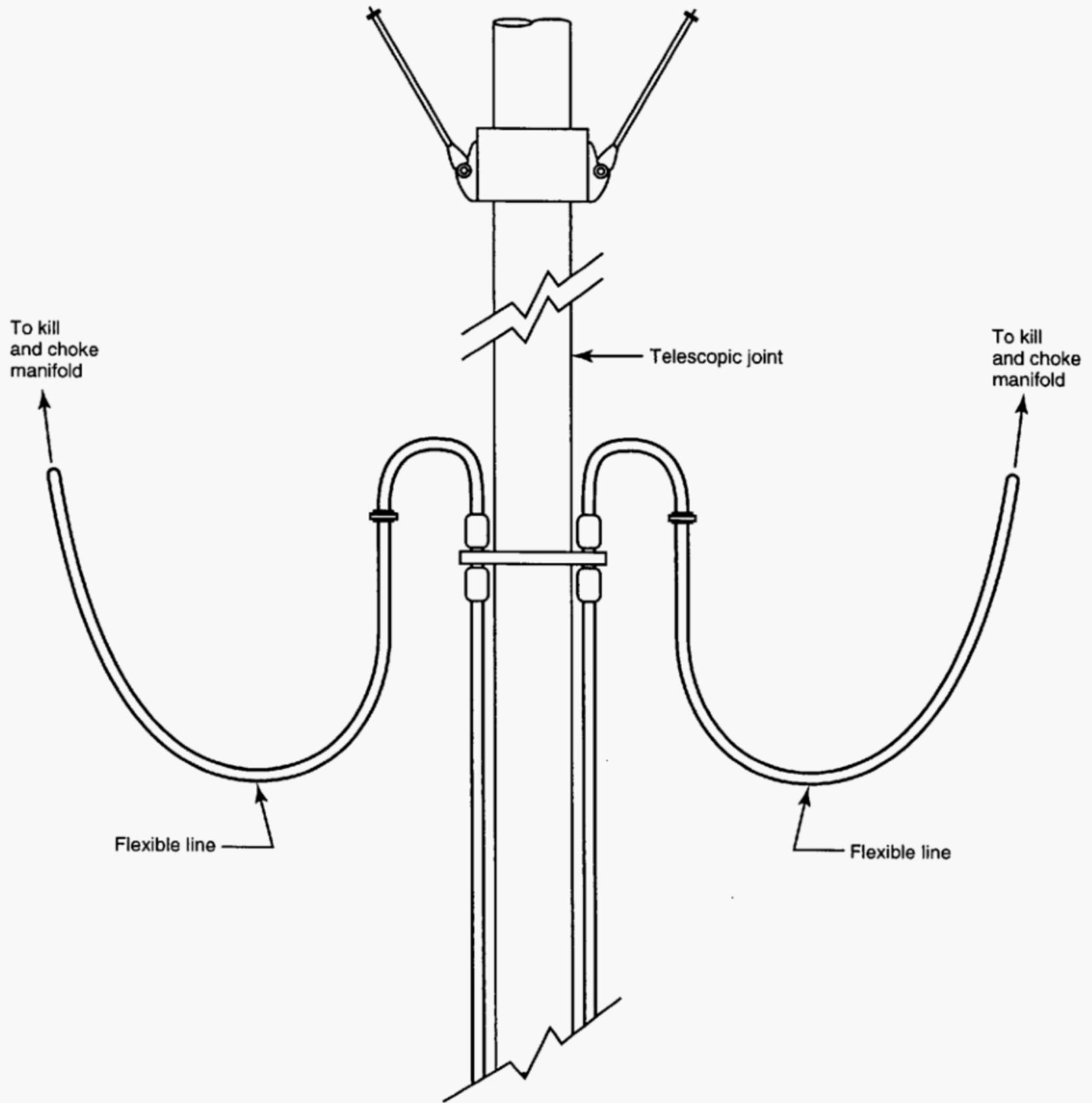


Figure 15—Example Flexible Connection at the Top of Marine Riser for Kill/Choke Lines

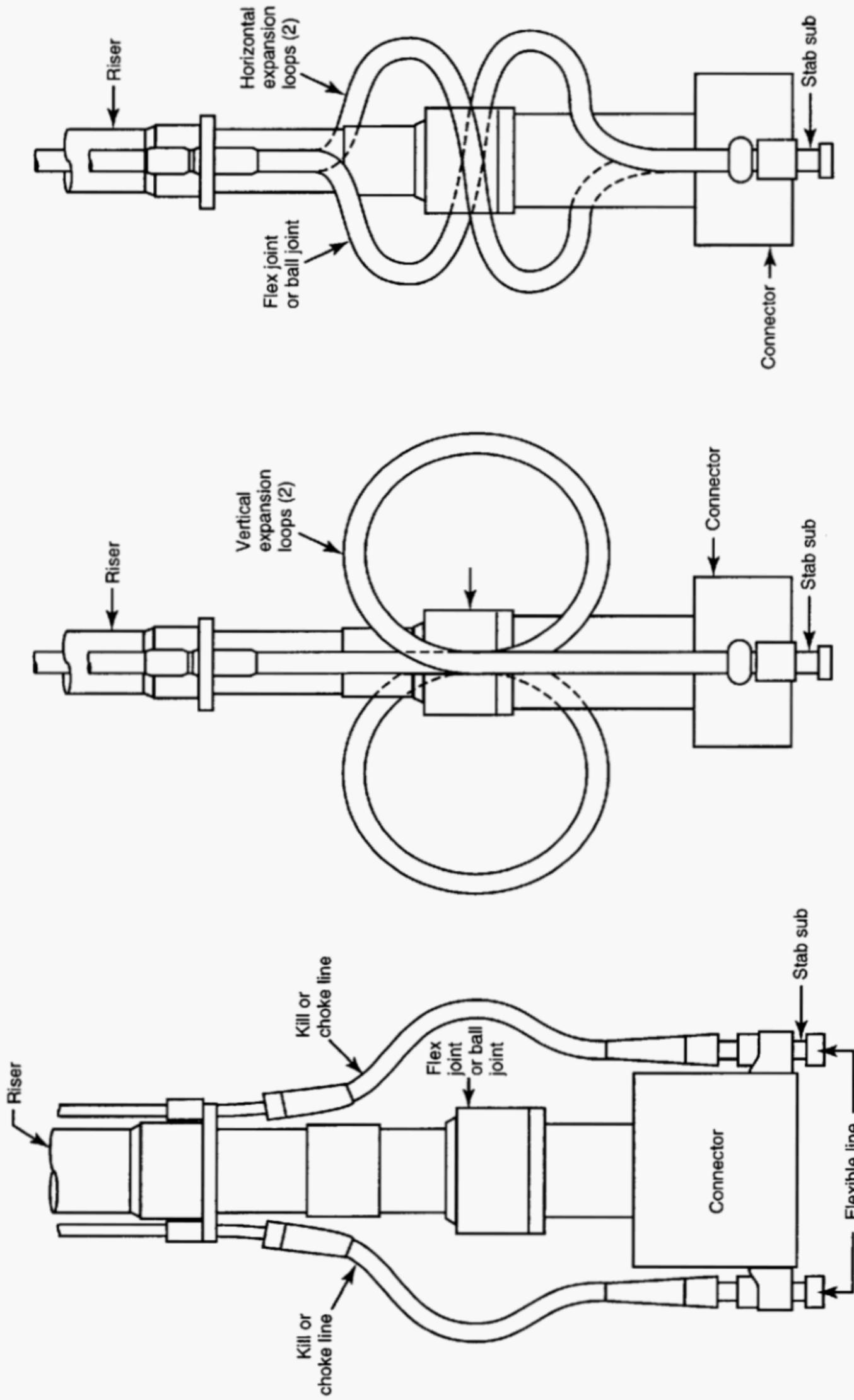


Figure 16—Example Flexible Connection at the Bottom of Marine Riser for Kill/Choke Lines

- c. Accumulator bottles for storing pressurized control fluid.
- d. Hydraulic control manifold for regulating the control fluid pressure and directing the power fluid flow to operate the system functions (BOPs and choke and kill valves).
- e. Remote control panels for operating the hydraulic control manifold from remote locations.
- f. Hydraulic control fluid.

12.2 ACCUMULATOR SYSTEMS

Accumulator bottles are containers that store hydraulic fluid under pressure for use in effecting BOP closure. Through use of compressed nitrogen gas, these containers store energy that can be used to further enhance BOP function response time, and to serve as a backup source of hydraulic power in case of pump failure. There are two types of accumulator bottles in common usage, separator and float types. The separator type uses a flexible diaphragm to effect positive separation of the nitrogen gas from the hydraulic fluid. The float type utilizes a floating piston to effect separation of the nitrogen gas from the hydraulic fluid.

12.3 ACCUMULATOR VOLUMETRIC CAPACITY

12.3.1 For the purpose of this section, the following definitions apply:

- a. **Stored Hydraulic Fluid.** The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.
- b. **Usable Hydraulic Fluid.** The hydraulic fluid recoverable from the accumulator system between the maximum accumulator operating pressure and 200 psi (1.38 MPa) above precharge pressure.
- c. **Minimum Calculated Operating Pressure.** The minimum calculated pressure to effectively close and seal a ram-type BOP against a wellbore pressure equal to the maximum rated working pressure of the BOP divided by the closing ratio specified for that BOP.
- d. **Component Minimum Operating Pressure Recommended by the Manufacturer.** The minimum operating pressure to effectively close and seal ram-type or annular-type preventers under normal operating conditions, as prescribed by the manufacturer.

12.3.2 BOP systems should have sufficient usable hydraulic fluid volume (with pumps inoperative) to close one annular-type preventer, all ram-type preventers from a full-open position, and open one HCR valve against zero wellbore pressure. After closing one annular preventer, all ram-type preventers, and opening one HCR valve, the remaining pressure shall be 200 psi (1.38 MPa) or more above the minimum recommended precharge pressure.

Note: The capability of the shear ram preventer and the ram operator should be verified with the manufacturer(s) for the planned drill string. The design

of the shear ram BOP and/or metallurgical differences among drill pipe manufacturers may necessitate high closing pressure for shear operations.

12.3.3 **Accumulator Response Time.** Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For surface installations, the BOP control system should be capable of closing each ram BOP within 30 seconds. Closing time should not exceed 30 seconds for annular BOPs smaller than 18³/₄ inches (47.63 cm) nominal bore and 45 seconds for annular preventers of 18³/₄ inches (47.63 cm) nominal bore and larger. Response time for choke and kill valves (either open or close) should not exceed the minimum observed ram close response time.

Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed effecting a seal. A BOP is considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

12.3.4 **Operating Pressure.** No accumulator bottle should be operated at a pressure greater than its rated working pressure.

12.3.5 **Accumulator Precharge.** The precharge pressure on each accumulator bottle should be measured prior to each BOP stack installation on each well and adjusted if necessary. The minimum precharge pressure for a 3000 psi (20.7 MPa) working pressure accumulator should be 1000 psi (6.9 MPa). The minimum precharge pressure for a 5000 psi (34.5 MPa) working pressure accumulator should be 1500 psi (10.3 MPa). Only nitrogen gas should be used for accumulator precharge. The precharge pressure should be checked and adjusted to within 100 psi (0.69 MPa) of the selected precharge pressure at the start of drilling each well.

12.3.6 **Accumulator Valves, Fittings, and Pressure Gauges.** Multi-bottle accumulator banks should have valving for bank isolation. An isolation valve should have a rated working pressure at least equivalent to the designed working pressure of the system to which it is attached and must be in the open position except when accumulators are isolated for servicing, testing, or transporting.

A pressure gauge for measuring the accumulator precharge pressure should be readily available for installation at any time. Pressure gauges should be calibrated to 1 percent of full scale at least every three (3) years.

12.4 PUMP SYSTEMS

12.4.1 A pump system consists of one or more pumps. Each pump system (primary and secondary) should have independent power sources, such as electric or air. Each pump system should have sufficient quantity and sizes of pumps to satisfactorily perform the following: With the accumulators isolated from service, the pump system should be capable of

closing the annular BOP (excluding the diverter) on the minimum size drill pipe being used, open the hydraulically operated choke valve(s), and provide the operating pressure level recommended by the annular BOP manufacturer to effect a seal on the annulus within two minutes.

12.4.2 The same pump system(s) may be used to provide power fluid to control both the BOP stack and the diverter system.

12.4.3 Each pump system should provide a discharge pressure at least equivalent to the BOP control system working pressure. Air pumps should be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

12.4.4 Each pump system should be protected from overpressurization by a minimum of two devices to limit the pump discharge pressure. One device, normally a pressure limit switch, should limit the pump discharge pressure so that it will not exceed the working pressure of the BOP control system. The second device, normally a relief valve, should be sized to relieve at a flow rate at least equal to the design flow rate of the pump systems and should be set to relieve at not more than ten percent over the control unit pressure. Devices used to prevent pump system overpressurization should be installed directly in the control system supply line to the accumulators and should not have isolation valves or any other means that could defeat their intended purpose. Rupture disc(s) or relief valve(s) that do not automatically reset are not recommended.

12.4.5 Electrical and/or air (pneumatic) supply for powering pumps should be available at all times such that the pumps will automatically start when the system pressure has decreased to approximately 90 percent of the system working pressure and automatically stop within plus zero or minus 100 psi (0.69 MPa) of the BOP control system working pressure.

12.5 BOP CONTROL SYSTEM VALVES, FITTINGS, LINES, AND MANIFOLD

12.5.1 PRESSURE RATING

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., should have a working pressure at least equal to the rated working pressure of the control system. BOP control system rated working pressure is usually 3,000 psi (20.7 MPa).

12.5.2 CONFORMITY OF PIPING SYSTEMS

All piping components and all threaded pipe connections installed on the BOP control system should conform to the design and tolerance specifications for American National Standards Taper Pipe Threads as specified in ANSI B1.20.1.

Pipe and pipe fittings should conform to specifications of ANSI B31.3. If weld fittings are used, the welder shall be certified for the applicable procedure required. Welding should be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with Article II of *ASME Boiler and Pressure Vessel Code*, Section IX.

All rigid or flexible lines between the control system and BOP stack should be flame retardant, including end connections, and should have a working pressure equal to the working pressure of the BOP control system.

All control system interconnect piping, tubing, hose, linkages, etc., should be protected from damage during drilling operations, or day-to-day equipment movement.

12.5.3 VALVES, FITTINGS, AND OTHER COMPONENTS

The installation should be equipped with the following:

- a. The manifold should be equipped with a full-bore valve to which a separate operating fluid pump can be easily connected.
- b. The control system should be equipped to allow isolation of both the pumps and the accumulators from the manifold and annular control circuits, thus allowing maintenance and repair work.
- c. The control system should be equipped with accurate pressure gauges to indicate: (1) accumulator pressure, (2) regulated manifold pressure, (3) annular pressure, and (4) air supply pressure.
- d. The control system should be equipped with a pressure regulating valve to permit manual control of the annular preventer operating pressure.
- e. The control system should be equipped with a regulating valve to control the operating pressure on the ram BOPs. The control unit should be equipped with a bypass line and valve to allow full accumulator pressure to be applied on the manifold, if desired.
- f. Control valves must be clearly marked to indicate (1) which preventer or choke line valve each control valve operates, and (2) the position of the valves (i.e., open, closed, neutral). Each BOP control valve should be in the open position (not the neutral position) during drilling operations. The choke line hydraulic valve should be in the closed position during normal operations. The control valve handle that operates the blind rams should be protected to avoid unintentional operation, but allow full operation from the remote panel without interference.
- g. All pressure gauges on the BOP control system should be calibrated to an accuracy of 1 percent of full scale at least every 3 years.

12.6 CONTROL SYSTEM FLUIDS AND CAPACITY

12.6.1 CONTROL SYSTEM FLUID

A suitable hydraulic fluid (hydraulic oil or fresh water containing a lubricant) should be used as the closing unit control operating fluid. Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32° F (0° C) are anticipated. The use of diesel oil, kerosene, motor oil, chain oil, or any other similar fluid is not recommended because of the possibility of explosions or resilient seal damage.

12.6.2 FLUID CAPACITY

Each closing unit should have a fluid reservoir with a capacity equal to at least twice the usable fluid capacity of the accumulator system. Air breather outlets, of sufficient size, should be installed to avoid pressurization of the tank during hydraulic transfers or nitrogen transfers if a nitrogen backup system is installed.

12.7 HYDRAULIC CONTROL UNIT LOCATION

The hydraulic control unit should be located in a safe place that is easily accessible to rig personnel in an emergency. It should also be located to prevent excessive drainage or flow back from the operating lines to the reservoir. Should the accumulator banks be located a substantial distance from or below the BOP stack, additional reservoir volume or alternative means should be provided to compensate for flow back in the closing lines.

12.8 REMOTE CONTROL STATIONS

The installation should be equipped with a driller remote control panel such that the operation of each BOP and control valve can be controlled from a position readily accessible to the driller. Consideration should be given to the need for an additional remote control station(s) at a safe distance from the rig floor.

13 Control Systems for Subsea BOP Stacks

13.1 GENERAL

In addition to the equipment used for surface mounted BOP stacks, subsea control systems utilize pilot signals and readbacks that are transmitted to and received from subsea control valves in order to effect control of the subsea BOP. Dual controls are typical for increased reliability to transmit hydraulic supply power fluid subsea. Two independent pilot signal transmission/readback means are provided to control the two subsea control pods mounted on the lower marine riser package (LMRP). Both the control pods house pilot

operated control valves for directing power fluid to and read-back from the BOP stack.

Types of subsea control systems include hydraulic control, electro-hydraulic control, and multiplexed electro-hydraulic control. The elements of the BOP control system normally include:

- a. Storage (reservoir) equipment for supplying ample control fluid to the pumping system.
- b. Pumping systems for pressurizing the control fluid.
- c. Accumulator bottles for storing pressurized control fluid. Some accumulator bottles may be located subsea on the BOP stack assembly.
- d. Hydraulic control manifold for regulating the control fluid pressure and directing the power fluid flow to operate the system functions (BOPs and choke and kill valves).
- e. Remote control panels for operating the hydraulic control manifold from remote locations.
- f. Hydraulic control fluid.
- g. Umbilical control hose bundle(s) and reel(s).
- h. Control pod(s) located on the BOP.

13.2 ACCUMULATOR SYSTEMS

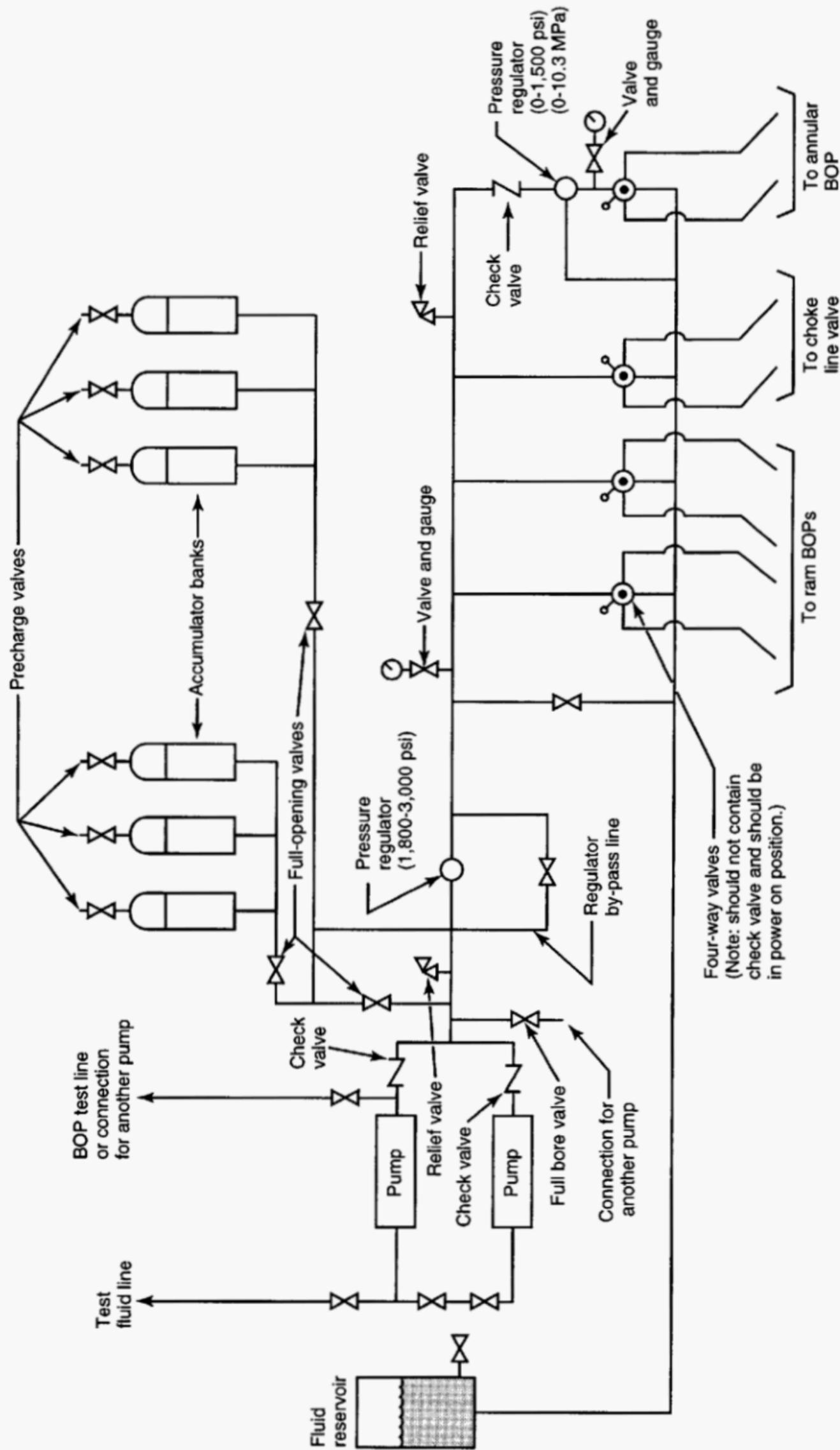
Accumulator bottles are containers that store hydraulic fluid under pressure for use in effecting BOP closure. Through use of compressed nitrogen gas, these containers store energy that can be used to decrease BOP function response time, and to serve as a backup source of hydraulic power in case of pump failure. There are two types of accumulator bottles in common usage, separator and float types. The separator type uses a flexible diaphragm to effect positive separation of the nitrogen gas from the hydraulic fluid. The float type utilizes a floating piston to effect separation of the nitrogen gas from the hydraulic fluid.

Accumulators may be mounted on the subsea BOP stack to further enhance response time and to add to the total backup supply volume in case of pump failure. The accumulator fluid capacity should be protected from discharge through the supply lines by suitable devices such as pilot operated check valves.

13.3 ACCUMULATOR VOLUMETRIC CAPACITY

13.3.1 For the purpose of this section, the following definitions apply:

- a. **Stored Hydraulic Fluid.** The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.
- b. **Usable Hydraulic Fluid.** The hydraulic fluid recoverable from the accumulator system between the maximum accumulator operating pressure and 200 psi (1.38 MPa) above precharge pressure.



Four-way valves
(Note: should not contain
check valve and should be
in power on position.)

Figure 17—Example Hydraulic Control Schematic for a BOP Control System

c. **Minimum Calculated Operating Pressure.** The minimum calculated pressure to effectively close and seal a ram-type BOP against a wellbore pressure equal to the maximum rated working pressure of the BOP. This pressure is equal to the maximum working pressure of the BOP divided by the closing ratio specified for that BOP.

d. **Component Minimum Operating Pressure Recommended by the Manufacturer.** The minimum operating pressure to effectively close and seal a ram-type or annular-type preventer under normal operating conditions, as prescribed by the manufacturer.

13.3.2 BOP systems should have sufficient usable hydraulic fluid volume (with pumps inoperative) to close and open one annular-type preventer and all ram-type preventers from a full-open position against zero wellbore pressure. After closing and opening one annular preventer and all ram-type preventers, the remaining pressure shall be 200 psi (1.38 MPa) or more above the minimum recommended precharge pressure.

Note: The capability of the shear ram preventer and the ram operator should be verified with the equipment manufacturer for the planned drill string. The design of the shear ram BOP and/or metallurgical differences among drill pipe manufacturers may necessitate high closing pressure for shear operations.

13.3.3 The subsea accumulator bottle capacity calculations should compensate hydrostatic pressure gradient at the rate of 0.445 psi per foot (0.010067 MPa per meter) of water depth. For example, the hydrostatic head at 500 feet (152.4 meters) water depth is 222.5 psi (1.54 MPa). This would require that all pressure values in this example's calculations be increased by this amount.

13.3.4 Subsea accumulators shall have isolation and dumping capabilities.

13.3.5 ACCUMULATOR RESPONSE TIME

Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For subsea installations, the BOP control system should be capable of closing each ram BOP in 45 seconds or less. Closing time should not exceed 60 seconds for annular BOPs. Operating response time for choke and kill valves (either open or close) should not exceed the minimum observed ram BOP close response time. Time to unlatch the lower marine riser package should not exceed 45 seconds.

Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed effecting a seal. A BOP is considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

13.3.6 OPERATING PRESSURE

No accumulator bottle should be operated at a pressure greater than its rated working pressure.

13.3.7 ACCUMULATOR PRECHARGE

The precharge pressure on each accumulator bottle should be measured prior to each BOP stack installation on each well and adjusted if necessary. The minimum precharge pressure for a 3,000 psi (20.7 MPa) working pressure accumulator unit should be 1,000 psi (6.9 MPa). The minimum precharge pressure for a 5,000 psi (34.5 MPa) working pressure accumulator unit should be 1,500 psi (10.3 MPa). Only nitrogen gas should be used for accumulator precharge. The precharge pressure should be checked and adjusted to within 100 psi (0.69 MPa) of the selected precharge pressure at the start of drilling each well.

For subsea accumulators, the precharge pressure shall compensate for the water depth the BOPs will be operating in, as described in 13.3.3. For example, if the precharge pressure of the surface accumulators is 1,000 psi (6.9 MPa) and the BOPs will be in 500 feet (152.4 meters) water depth, the subsea accumulators should be precharged to 1,222.5 psi (8.43 MPa).

13.3.8 ACCUMULATOR VALVES, FITTINGS, AND PRESSURE GAUGES

Multi-bottle accumulator banks should have valving for bank isolation. An isolation valve should have a rated working pressure at least equivalent to the designed working pressure of the system to which it is attached and must be in the open position except when accumulators are isolated for servicing, testing, or transporting.

A pressure gauge for measuring the accumulator precharge pressure should be readily available for installation at any time. Pressure gauges should be calibrated to 1 percent of full scale at least every 3 years.

13.3.9 HYDRAULIC FLUID MIXING SYSTEM

The hydraulic fluid reservoir should be a combination of two or more storage sections; one section containing mixed fluid to be used in the operation of the BOPs, and the other section(s) containing the concentrated water-soluble hydraulic fluid to be mixed with water to form the mixed hydraulic fluid. This mixing system should be automatically controlled to maintain mixed fluid ratios and levels. The mixing system should be able to mix at a rate equal to the total pump system(s) output. In cold climates, an extra storage section and mixing system may be needed for glycol.

13.4 PUMP SYSTEMS

13.4.1 Each subsea BOP control system should have a minimum of two pump systems. Each pump system should have an independent power source, such as air or electric. The combination of all pump system(s) should be capable of charging the accumulator system from the minimum calculated operating pressure to the system maximum rated pressure in fifteen minutes.

13.4.2 The same pump system(s) may be used to produce power fluid for control of both the BOP stack and the diverter system.

13.4.3 Each pump system should provide a discharge pressure at least equivalent to the BOP control system working pressure. Air pumps should be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

13.4.4 Each pump system should be protected from overpressurization by a minimum of two devices to limit the pump discharge pressure. One device, normally a pressure limit switch, should limit the pump discharge pressure so that it will not exceed the working pressure of the BOP control system. The second device, normally a relief valve, should be sized to relieve at a flow rate at least equal to the design flow rate of the pump systems and should be set to relieve at not more than ten percent over the control unit pressure. Devices used to prevent pump system overpressurization should be installed directly in the control system supply line to the accumulators and should not have isolation valves or any other means that could defeat their intended purpose. Rupture disc(s) or relief valves that do not automatically reset are not recommended.

13.4.5 Electrical and/or air (pneumatic) supply for powering pumps should be available at all times such that the pumps will automatically start when the system pressure has decreased to approximately 90 percent of the system working pressure and automatically stop within plus zero or minus 100 psi (0.69 MPa) of the BOP control system working pressure.

13.4.6 Separate accumulators may be provided for the pilot control system that may be supplied by a separate pump or through a check valve from the main accumulator system. The dedicated pump, if used, can be either air powered or electric powered. Air pumps should be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply. Provision should be made to supply hydraulic fluid to the pilot accumulators from the main accumulator system if the pilot pump becomes inoperative.

13.5 REMOTE CONTROL AND MONITORING PANELS

13.5.1 GENERAL

The subsea BOP control system should have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations. One location should be in a non-classified (nonhazardous) area as defined in API Recommended Practice 500. This may be accomplished by placing the main hydraulic control unit in a nonhazardous area remote from the rig floor and a full function remote control panel (driller's panel) accessible to the driller on the rig floor. In addition to the driller's panel and main hydraulic control unit, at least one other remote panel should be provided for BOP stack functions.

13.6 UMBILICAL CONTROL HOSE BUNDLES AND SUBSEA ACCUMULATORS

13.6.1 Umbilical control hose bundles provide the main supply of power fluid and pilot signals from the surface hydraulic control manifold to the subsea control pods mounted on the BOP stack. The subsea umbilical is run, retrieved, and stored on the hose reel.

13.6.2 The pilot signals are routed to the hose reels through the appropriate length of surface umbilical jumper hose bundle from the hydraulic connections located on the control manifold.

13.6.3 The main hydraulic power fluid supply is normally carried through a 1-inch (2.54-centimeter) nominal size supply hose in the hose bundle to the subsea control pod. An alternative to this system is installation of a rigid pipe (conduit) on the marine riser.

13.7 HOSE REELS AND HOSE SHEAVES

13.7.1 Hose reels are used to store, run, and retrieve the umbilical hose bundles that communicate the main hydraulic power fluid supply and command pilot signals to the subsea mounted BOP control pods. The hose reels are equipped with hose reel manifolds having valves, regulators, and gauges for maintaining control through the subsea umbilical of selected functions during running and retrieving of the pod or lower marine riser package and/or the BOP stack. Additional hose handling equipment includes hose sheaves used to support and change direction of the subsea umbilical while maintaining the specified minimum bend radius recommended by the umbilical manufacturer.

13.7.2 All functions required to run, land, or retrieve the lower marine riser package and/or the BOP stack should remain fully active during landing and retrieval.

13.7.3 Hose sheaves should facilitate running and retrieving the subsea umbilical from the hose reel through the moonpool and support the moonpool loop which is deployed to compensate for vessel heave.

13.7.3.1 Hose sheaves should be mounted to permit three-axis freedom of movement and prohibit damage to the umbilical in normal ranges of anticipated movement.

13.7.3.2 The hose sheave should permit installation of the umbilical without disconnecting from the hydraulic junction box assemblies to which the umbilical may be terminated.

13.8 SUBSEA CONTROL PODS

Some systems are two BOP stack systems where the larger stack has only one control pod. However, most systems are single stack where there are two completely redundant control pods on the BOP stack when drilling out from under surface casing. Each control pod should contain all necessary valves and regulators to operate the BOP stack functions. The control pods may be retrievable or nonretrievable. The hoses from each control pod should be connected to a shuttle valve that is connected to the function to be operated.

13.9 BOP CONTROL SYSTEM VALVES, FITTINGS, LINES, AND MANIFOLD

13.9.1 PRESSURE RATING

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., should have a working pressure at least equal to the working pressure of the control system. BOP control system rated working pressure is usually 3,000 psi (20.7 MPa).

13.9.2 CONFORMITY OF PIPING SYSTEMS

All piping components and all threaded pipe connections installed on the BOP control system should conform to the design and tolerance specifications for American National Standards Taper Pipe Threads as specified in ANSI B1.20.1. Pipe and pipe fittings should conform to specifications of ANSI B31.3. If weld fittings are used, the welder shall be certified for the applicable procedure required. Welding should be performed in accordance with a written weld procedure specification (WPS), written and qualified in accordance with Article II of *ASME Boiler and Pressure Vessel Code*, Section IX.

All rigid or flexible lines between the control system and riser should be flame retardant, including end connections, and should have a working pressure equal to the working pressure of the BOP control system.

All control system interconnect piping, tubing, hose, linkages, etc., should be protected from damage during drilling operations, or day-to-day equipment movement.

13.9.3 VALVES, FITTINGS, AND OTHER COMPONENTS

The installation should be equipped with the following:

- a. The manifold should be equipped with a full-bore valve to which a separate operating fluid pump can be easily connected.
- b. The control system should be equipped to allow isolation of both pump systems and accumulators from the manifold and annular control circuits thus, allowing maintenance and repairs.
- c. The control system should be equipped with accurate pressure gauges to indicate: (1) accumulator pressure, (2) regulated manifold pressure, (3) annular pressure, (4) air supply pressure, (5) manifold and annular readback pressures, and (6) flowmeter.
- d. The control system should be equipped with a pressure regulating valve to permit manual control of the annular preventer operating pressure.
- e. The control system should be equipped with a regulating valve to control the operating pressure on the ram BOPs. The control unit should be equipped with a bypass line and valve to allow full accumulator pressure to be applied to the manifold, if desired.
- f. Control valves must be clearly marked to indicate (1) which preventer or choke/kill valve(s) each control valve operates, and (2) the position of the valves (i.e., open, closed, block or vent). Each BOP control valve should be in the open position (not in the neutral position) during drilling operations. Each choke/kill line hydraulic valve should be in the closed position during drilling operations. The control valve that operates the blind-shear rams should be protected to avoid unintentional operation from the remote panel without interference.
- g. All pressure gauges on the BOP control system should be calibrated to an accuracy 1 percent of full scale at least every 3 years.

13.10 CONTROL SYSTEM FLUIDS AND CAPACITY

13.10.1 CONTROL SYSTEM FLUID

A suitable hydraulic fluid should be used as the closing unit control operating fluid. Sufficient volume of glycol must be added to any closing unit fluid containing water if ambient temperatures below 32° F (0° C) are anticipated.

13.10.2 FLUID CAPACITY

Each closing unit should have a fluid reservoir with a capacity equal to at least twice the usable fluid capacity of the accumulator system.

14 Electro-hydraulic and Multiplex Control Systems for Subsea BOP Stacks

14.1 GENERAL

In deep water operations, hydraulic signal transmission time is lengthened by physical expansion of the fluid conductor hose as the internal pressure surges. Electro-hydraulic and multiplex control systems can be used in deep water where response times of hydraulic signals are too lengthy. Electrical command signals transmitted over lengthy subsea cables have shorter response times than hydraulic pilot signals transmitted over hose bundles of equal length.

Electrical command signals operate subsea solenoid valves which, in turn, provide hydraulic pilot signals directly to operate the pod valves that direct power fluid to the subsea functions.

Electro-hydraulic control systems have parallel capability to execute and receive commands, whereas multiplex control systems process multiple signals on each conductor set. Electro-hydraulic systems have conductor wires in the subsea umbilical cable dedicated to each function.

Multiplex (MUX) systems serialize and code the command signals that are then sent subsea via shared conductors in the umbilical cable. Multiplex control system logic may incorporate additional security by requiring verification before execution of the function. Subsea data are electrically transmitted to the surface.

14.2 ACCUMULATOR VOLUMETRIC CAPACITY

14.2.1 For purposes of this section, the following definitions apply:

- a. **Stored Hydraulic Fluid.** The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.
- b. **Usable Hydraulic Fluid.** The hydraulic fluid recoverable from the accumulator system between the maximum accumulator operating pressure and 200 psi (1.38 MPa) above precharge pressure.
- c. **Minimum Calculated Operating Pressure.** The minimum calculated pressure to effectively close and seal a ram-type BOP against a wellbore pressure equal to the maximum rated working pressure of the BOP. This pressure is equal to the maximum working pressure of the BOP divided by the closing ratio specified for that BOP.
- d. **Component Minimum Operating Pressure Recommended by the Manufacturer.** The minimum operating pressure to effectively close and seal a ram-type or annular-type preventer under normal operating conditions, as prescribed by the manufacturer.

14.2.2 BOP systems should have sufficient usable hydraulic fluid volume (with pumps inoperative) to close and open one annular-type preventer and all ram-type preventers from a full-open position against zero wellbore pressure. After closing and opening one annular preventer and all ram-type preventers, the remaining pressure shall be 200 psi (1.38 MPa) or above the minimum recommended pressure.

Note: The capability of the shear ram preventer and the ram operator should be verified with the equipment manufacturer for the planned drill string. The design of the shear ram BOP and/or metallurgical differences among drill pipe manufacturers may necessitate high closing pressure for shear operations.

14.2.3 The subsea accumulator bottle capacity calculations should compensate hydrostatic pressure gradient at the rate of 0.445 psi per foot (0.010067 MPa/meter) of water depth. For example, the hydrostatic head at 500 feet (152.4 meters) water depth is 222.5 psi (1.54 MPa). This would require that all pressure values in this example's calculations be increased by this amount.

14.2.4 Subsea accumulators shall have isolation and dumping capabilities.

14.2.5 **Accumulator Response Time.** Response time between activation and complete operation of a function is based on BOP or valve closure and seal off. For subsea installations, the BOP control system should be capable of closing each ram BOP in 45 seconds or less. Closing time should not exceed 60 seconds for annular BOPs. Operating response time for choke and kill valves (either open or close) should not exceed the minimum observed ram BOP close response time. Time to unlatch the lower marine riser package should not exceed 45 seconds.

Measurement of closing response time begins at pushing the button or turning the control valve handle to operate the function and ends when the BOP or valve is closed effecting a seal. A BOP is considered closed when the regulated operating pressure has recovered to its nominal setting. If confirmation of seal off is required, pressure testing below the BOP or across the valve is necessary.

14.2.6 **Hydraulic Fluid Mixing System.** The hydraulic fluid reservoir should be a combination of two or more storage sections; one section containing mixed fluid to be used in the operation of the BOPs, and the other section(s) containing the concentrated water-soluble hydraulic fluid to be mixed with water to form the mixed hydraulic fluid. This mixing system should be automatically controlled to maintain mixed fluid ratios and levels. The mixing system should be able to mix at a rate equal to the total pump system(s) output. In cold climates, an extra storage section and mixing system may be needed for glycol.

14.3 PUMP SYSTEMS

14.3.1 Each subsea BOP control system should have a minimum of two pump systems. Each pump system (primary and secondary) should be employed having independent power sources, such as electric, air. The combination of all pump system(s) should be capable of charging the accumulator system from the minimum calculated operating pressure to the system maximum rated pressure in fifteen minutes.

14.3.2 The same pump system(s) may be used to produce power fluid for control of both the BOP stack and the diverter system.

14.3.3 Each pump system should provide a discharge pressure at least equivalent to the BOP control system working pressure. Air pumps should be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

14.3.4 Each pump system should be protected from over pressurization by a minimum of two devices to limit the pump discharge pressure. One device, normally a pressure limit switch, should limit the pump discharge pressure so that it will not exceed the working pressure of the BOP control system. The second device, normally a relief valve, should be sized to relieve at a flow rate at least equal to the design flow rate of the pump systems and should be set to relieve at not more than ten percent over the control unit pressure. Devices used to prevent pump system over pressurization should be installed directly in the control system supply line to the accumulators and should not have isolation valves or any other means that could defeat their intended purpose. Rupture disc(s) or relief valves that do not automatically reset are not recommended.

14.3.5 Electrical and/or air (pneumatic) supply for powering pumps should be available at all times such that the pumps will automatically start when the system pressure has decreased to approximately ninety percent (90 percent) of the system working pressure and automatically stop within plus zero or minus 100 psi (0.69 MPa) (+0 or -100 psi) of the BOP control system working pressure.

14.3.6 Separate accumulators may be provided for the pilot control system that may be supplied by a separate pump or through a check valve from the main accumulator system. The dedicated pump, if used, can be either air powered or electric powered. Air pumps should be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply. Provision should be made to supply hydraulic fluid to the pilot accumulators from the main accumulator system if the pilot pump becomes inoperative.

14.4 ELECTRICAL CONTROL UNIT

The electrical control unit should have a central control point (corresponding to the hydraulic control manifold of a hydraulic control system). Alternatively, each control panel may communicate directly and independently with each pod.

14.4.1 The electrical control unit should be supplied electrical power from an uninterruptible power supply.

14.4.2 The electrical control unit should be located in a safe, dry area. All functions should be operable from and monitored from a remote control panel located on the rig floor, interfacing with the central control unit.

14.4.3 The electrical control unit should maintain function status memory in the event of power interruption. Upon restoration of power, the system should display the status of all functions as they were prior to the loss of power.

14.5 REMOTE CONTROL AND MONITORING PANELS

The subsea BOP control system should have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations. One location should be in a non-classified (nonhazardous) area as defined in API Recommended Practice 500. This may be accomplished by placing the main hydraulic control unit in a nonhazardous area remote from the rig floor and a full function remote control panel (driller's panel) accessible to the driller on the rig floor. In addition to the driller's panel and main hydraulic control unit, at least one other remote panel should be provided for BOP stack functions.

14.6 SUBSEA UMBILICAL CABLES AND CONNECTORS

The subsea umbilical cable is run, retrieved, and stored on a cable reel. The subsea umbilical electrical cable supplies power, communications, and control of the subsea control pods. The electrical conductors and electrical insulation should not be used as load bearing components in the cable assembly.

All underwater electrical umbilical cable terminations should be sealed to prevent water migration up the cable in the event of connector failure or leakage and to prevent water migration from the cable into the subsea connector termination in the event of water intrusion into the cable. Individual connector terminations should be physically isolated so that seawater intrusion does not cause electrical shorting. A pressure compensated junction box containing dielectric fluid may be used to accomplish this.

14.7 SUBSEA ELECTRICAL EQUIPMENT

14.7.1 All electrical connections that may be exposed to seawater should be protected to prevent overloading the subsea electrical supply system in the event of water intrusion into connections.

14.7.2 All electrical apparatus used subsea should be temperature rated to be fully operational on a continuous basis while exposed to surface ambient conditions without the use of auxiliary cooling or heating.

14.7.3 All subsea electrical equipment should be suitable for use subsea with particular attention paid to mechanical vibration and shock induced while drilling. Plug-in devices should be mechanically secured.

14.7.4 Auxiliary subsea electrical equipment that is not directly related to the BOP control system should be connected in a manner to avoid disabling the BOP control system in the event of a failure in the auxiliary equipment.

14.7.5 Subsea electrical equipment should be galvanically isolated from any surface exposed to seawater.

15 Auxiliary Equipment—Surface BOP Installations

15.1 KELLY VALVES

An upper kelly valve is installed between the swivel and the kelly. A lower kelly valve is installed immediately below the kelly.

15.2 DRILL PIPE SAFETY VALVE

A spare drill pipe safety valve should be readily available (i.e., stored in open position with wrench accessible) on the rig floor at all times. This valve or valves should be equipped to screw into any drill string member in use. The outside diameter of the drill pipe safety valve should be suitable for running into the hole.

15.3 INSIDE BLOWOUT PREVENTER

An inside blowout preventer, drill pipe float valve, or drop-in check valve should be available for use when stripping the drill string into or out of the hole. The valve(s), sub(s), or profile nipple should be equipped to screw into any drill string member in use.

15.4 FIELD TESTING

The kelly valves, drill pipe safety valve, and inside blowout preventer should be tested in accordance with applicable recommendations in Section 17.

15.5 DRILL STRING FLOAT VALVE

A float valve is placed in the drill string to prevent upward flow of fluid or gas inside the drill string. The float valve is a special type of back pressure or check valve. A float valve in good working order will prohibit backflow and a potential blowout through the drill string.

The drill string float valve is usually placed in the lowermost portion of the drill string, between two drill collars or between the drill bit and drill collar. Since the float valve prevents the drill string from being filled with fluid through the bit as it is run into the hole, the drill string must be filled from the top, at the drill floor, to prevent collapse of the drill pipe.

There are two types of float valves:

- a. The flapper-type float valve offers the advantage of having an opening through the valve that is approximately the same inside diameter as that of the tool joint. This valve will permit the passage of balls, or go-devils, which may be required for operation of tools inside the drill string below the float valve.
- b. The spring-loaded ball, or dart, and seat float valve offers the advantage of an instantaneous and positive shut off of backflow through the drill string.

These valves are not full-bore and thus cannot sustain long duration or high volume pumping of drilling fluid or kill fluid. However, a wireline retrievable valve that seals in a profiled body that has an opening approximately the same inside diameter as that of the tool joint may be used to provide a full-open access, if needed.

15.6 TRIP TANK

A trip tank is a low-volume, [100 barrels (15.9 m³) or less], calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well. A trip tank may be of any shape provided the capability exists for reading the volume contained in the tank at any liquid level. The readout may be direct or remote, preferably both. The size and configuration of the tank should be such that volume changes on the order of one-half barrel can be easily detected by the readout arrangement. Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations.

Other uses of the trip tank include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following a cement job, calibrating drilling fluid pumps, etc. The trip tank is also used to measure the volume of drilling fluid bled from or pumped into the well as pipe is stripped into or out of the well.

15.7 PIT VOLUME MEASURING AND RECORDING DEVICES

Automatic pit volume measuring devices are available which transmit a pneumatic or electric signal from sensors on the drilling fluid pits to recorders and signaling devices on the rig floor. These are valuable in detecting fluid gain or loss.

15.8 FLOW RATE SENSOR

A flow rate sensor mounted in the flow line is recommended for early detection of formation fluid entering the wellbore or a loss of returns.

15.9 MUD/GAS SEPARATOR

The mud/gas separator is used to separate gas from drilling fluid that is gas cut. The separated gas can then be vented to a safe distance from the rig. Generally, two basic types of mud/gas separators are in use. The most common type is the atmospheric mud/gas separator, sometimes referred to as a *gas buster* or *poor-boy separator*. Another type of mud/gas separator is designed such that it can be operated at moderate back pressure, usually less than 100 psi (0.69 MPa), although some designs are operated at gas vent line pressure which is atmospheric plus line friction drop. All separators with a liquid level control may be referred to as pressurized mud/gas separators. Both the atmospheric and pressurized mud/gas separators have advantages and disadvantages. Some guidelines are common to both types of mud/gas separators. A bypass line to the flare stack must be provided in case of malfunction or in the event the capacity of the mud/gas separator is exceeded. Precautions must also be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the wall of the vessel. Provisions must be made for easy clean out of the vessels and lines in the event of plugging. Unless specifically designed for such applications, use of the rig mud/

gas separator is not recommended for well production testing operations.

The dimensions of a separator are critical in that they define the volume of gas and fluid a separator can effectively handle. An example of some mud/gas separator sizing guidelines can be found in SPE Paper No. 20430: *Mud Gas Separator Sizing and Evaluation*, G.R. MacDougall, December 1991.

15.10 DEGASSER

A degasser may be used to remove entrained gas bubbles in the drilling fluid that are too small to be removed by the mud/gas separator. Most degassers make use of some degree of vacuum to assist in removing this entrained gas. The drilling fluid inlet line to the degasser should be placed close to the drilling fluid discharge line from the mud/gas separator to reduce the possibility of gas breaking out of the drilling fluid in the pit.

15.11 FLARE LINES

All flare lines should be as long as practical with provisions for flaring during varying wind directions. Flare lines should be as straight as possible and should be securely anchored.

15.12 STAND PIPE CHOKE

An adjustable choke mounted on the rig stand pipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed off pressure between BOPs during stripping operations. Refer to Figure 18 for an example stand pipe choke installation.

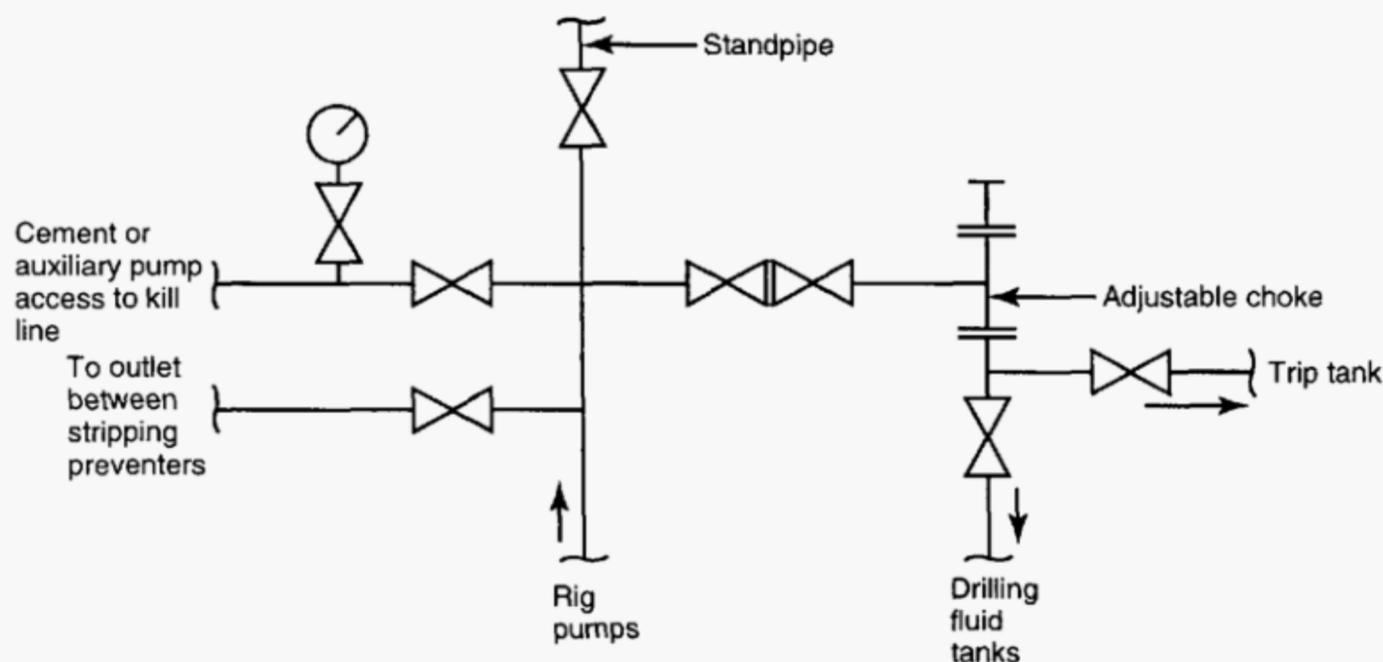


Figure 18—Example Standpipe Choke Installation

15.13 TOP DRIVE EQUIPMENT

There are two ball valves (sometimes referred to as *kelly valves* or *kelly cocks*) located on top drive equipment. The upper valve is air or hydraulically operated and controlled at the driller's console. The lower valve is a standard ball kelly valve (sometimes referred to as a *safety valve*) and is manually operated, usually by means of a large hexagonal wrench.

Generally, if it becomes necessary to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the top drive valves. However, flow up the drill pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions:

- a. Once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve.
- b. Most top drive manual valves cannot be stripped into $7\frac{5}{8}$ -inch (19.37 cm) or smaller casing.
- c. Once the top drive's manual valve is disconnected from the top drive, another valve or spacer must be installed to take its place.

16 Auxiliary Equipment—Subsea BOP Installations

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There are two types of float valves:

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- b. The spring-loaded ball, or dart, and seat float valve offers the advantage of an instantaneous and positive shut off of backflow through the drill string.

These valves are not full-bore and thus cannot sustain long duration or high volume pumping of drilling fluid or kill fluid. However, a wireline retrievable valve that seals in a profiled body that has an opening approximately the same inside diameter as that of the tool joint may be used to provide a full-open access, if needed.

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Generally, if it becomes necessary to prevent or stop flow up the drill pipe during tripping operations, a separate drill pipe valve should be used rather than either of the top drive valves. However, flow up the drill pipe might prevent stabbing this valve. In that case, the top drive with its valves can be used, keeping in mind the following cautions:

- Once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve.
- Most top drive manual valves cannot be stripped into $7\frac{5}{8}$ -inch (19.37 cm) or smaller casing.
- Once the top drive's manual valve is disconnected from the top drive, another valve or spacer must be installed to take its place.

16.14 GUIDE FRAMES

The BOP guide frame, a four-post structure attached to the BOP assembly, is a means for guiding the complete BOP/LMRP assembly's primary alignment onto the permanent guide base (refer to API Specification 17D). The upper section of the guide structure acts as primary guidance for the lower marine riser package. The guide structure also acts as the structural mounting for the various components of the remote control system and the choke/kill connectors or stab subs. The guide structure should have sufficient strength to protect the BOP stack from damage during handling and landing operations.

16.15 UNDERWATER TELEVISION

An underwater television system for visual inspection of the wellhead, BOP stack, marine riser, and other allied underwater components generally consists of a television camera and high intensity lights attached to a telescoping guide frame. This guide frame normally attaches around two of the guidelines. The assembly can be lowered and retrieved by a special umbilical cable that supports the package plus furnishes all electrical circuitry for the television camera and lights. Surface equipment includes a powered reel for the umbilical cable and a television monitor with allied electronic equipment and camera remote control.

16.16 SLOPE INDICATOR

This device is a circular glycerin-filled, plexiglas-covered slope indicator used to measure the angular deflection of components to which it is attached. A chrome plated ball bearing inside the slope indicator moves about circular black and white bands (graduated in degrees—painted on the base) to indicate angular position. Slope indicators are typically installed on the permanent guide base, BOP guide frame, LMRP guide frame, and first joint of riser above the lower ball/flex joint.

16.17 PIN CONNECTOR/HYDRAULIC LATCH

This hydraulically operated connector is used to connect the drilling riser to the conductor housing before the BOP stack is run to allow returns back to the surface. This assembly can also be used in conjunction with a subsea diverter application.

16.18 MUD BOOSTER LINE

Some riser strings are equipped with a mud booster line. This is an additional auxiliary line used to increase volume and flow rate of drilling fluid up the riser and to allow circulating the riser above a shut in BOP stack. Booster lines normally terminate into the riser just above the lower flex/ball joint on the LMRP.

16.19 AUXILIARY HYDRAULIC SUPPLY LINE (HARD/RIGID CONDUIT)

An auxiliary hydraulic supply line, referred as a *hard* or *rigid* conduit, is a metallic line attached to risers joints. The purpose of this auxiliary line is to supply control fluid from the surface accumulator system to the control pods and subsea accumulators mounted on the BOP and/or LMRP assemblies.

16.20 RISER TENSIONING SUPPORT RING

A riser tensioning support ring is attached (integrally or remotely) to the telescopic joint outer barrel to allow tensioning of the riser. The tensioning ring is the mechanical link

between the riser and the tensioner cables on the rig. The riser tensioners allow relative movement of the drilling vessel with respect to the stationary riser.

17 Testing and Maintenance—Surface BOP Stacks and Well Control Equipment

17.1 PURPOSE

The purposes for various field test programs on drilling well control equipment are to verify:

- a. That specific functions are operationally ready.
- b. The pressure integrity of the installed equipment.
- c. The control system and BOP compatibility.

17.2 TYPES OF TESTS

Test programs incorporate visual inspections, functional operations, pressure tests, maintenance practices, and drills. For purposes of this document, the following definitions are used for the basic types of tests:

17.2.1 INSPECTION TEST

The common collective term used to state the various procedural examination of flaws that may influence equipment performance. These inspection tests may include, but are not limited to visual, dimensional, audible, hardness, functional, and pressure tests. Inspection practices and procedures vary and are outside the scope of this document. An example of some inspection guidelines can be found in IADC/SPE Paper 23900, *A Field Guide for Surface BOP Equipment Inspections*, W. J. Kandel and D. J. Streu, February 1992.

17.2.2 FUNCTION TEST

The operation of a piece of equipment or a system to verify its intended operation. Function testing typically does not include pressure testing. Actuation test, operating test, and readiness test are other terms commonly used synonymously for function test.

17.2.3 PRESSURE TEST

Periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system. "Wellbore test" is another descriptive term frequently used synonymously for pressure test.

17.2.4 HYDRAULIC OPERATOR TEST

The application of a pressure test to any hydraulic operated component of hydraulic-actuated equipment. Hydraulic operator tests are typically specified by the manufacturer for such items as: BOP operator cylinders and bonnet assemblies,

hydraulic valve actuators, hydraulic connectors, etc. Operating chamber test is frequently used synonymously for hydraulic operator test.

Note: The definitions of test pressure, design pressure, operational characteristic tests, etc., as used in other API documents, may have meaning/intent more appropriate to manufacturing processes and the intended description may differ with field usage.

Site-specific applications of the different types of tests on well control equipment should be incorporated during field acceptance tests, initial rig-up tests, drills, periodic operating tests, maintenance practices, and drilling operations.

Note: Techniques and step-by-step or how-to-test procedures should be developed for each rig because of the varying equipment, different installation arrangements and well-specific drilling programs. The procedure for testing the BOP stack, drill string safety valves, choke/kill lines, and manifold upstream of the buffer chamber are usually similar for most rigs. Pressure test programs for the wellhead and casing should be prescribed by the operator on an individual well basis. Manufacturer operating and maintenance documents, contractor maintenance programs, and operating experiences should be incorporated into the specific test procedures.

17.2.5 CREW DRILLS

The proficiency with which drilling crews operate the well control equipment is as significantly important as the operational condition of the equipment. Crew drills and well control rig practices are outside the scope of this document and are addressed in API Recommended Practice 59.

17.3 TEST CRITERIA

17.3.1 FUNCTION TESTS

All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

- Function tests should be alternated from the driller's panel and from mini-remote panels, if on location. (Refer to worksheets in Appendix A.)
- Actuation times should be recorded as a data base for evaluating trends. (Refer to worksheets in Appendix A.)

17.3.2 PRESSURE TESTS

17.3.2.1 All blowout prevention components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi (1.38 to 2.1 MPa) and then to a high pressure.

- When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may continue to seal after the pressure is lowered and therefore misrepresenting a low pressure condition.
- A stable low test pressure should be maintained for at least 5 minutes.

17.3.2.2 The initial high pressure test on components that could be exposed to well pressure (BOP stack, choke manifold, and choke/kill lines) should be to the rated working pressure of the ram BOPs or to the rated working pressure of the wellhead that the stack is installed on, whichever is lower. Initial pressure tests are defined as those tests that should be performed on location before the well is spudded or before the equipment is put into operational service.

- Diverter systems are typically pressure tested to a low pressure only (refer to API Recommended Practice 64).
- Annular BOPs, with a joint of drill pipe installed, may be tested to the test pressure applied to the ram BOPs or to a minimum of 70 percent of the annular preventer working pressure, whichever is the lesser.
- The lower kelly valves, kelly, kelly cock, drill pipe safety valves, inside BOPs and top drive safety valves, should be tested with water pressure applied from below to a low pressure of 200-300 psi (1.38 to 2.1 MPa) then to the rated working pressure.
- There may be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these should be covered in the site-specific well control pressure test program.

17.3.2.3 Subsequent high pressure tests on the well control components should be to a pressure greater than the maximum anticipated surface pressure, but not to exceed the working pressure of the ram BOPs. The maximum anticipated surface pressure should be determined by the operator based on specific anticipated well conditions.

Annular BOPs, with a joint of drill pipe installed, should be tested to a minimum of 70 percent of their working pressure or to the test pressure of the ram BOPs, whichever is less. Subsequent pressure tests are tests that should be performed at identified periods during drilling and completion activity on a well.

- A stable high test pressure should be maintained for at least 5 minutes. With larger size annular BOPs some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This *packer creep* movement should be considered when monitoring the pressure test of the annular.
- Pressure test operations should be alternately controlled from the various control stations.

17.3.2.4 The pressure test performed on hydraulic chambers of annular BOPs should be to at least 1,500 psi (10.3 MPa). Initial pressure tests on hydraulic chambers of ram BOPs and hydraulically operated valves should be to the maximum operating pressure recommended by the manufacturer.

- The tests should be run on both the opening and the closing chambers.
- Pressure should be stabilized for at least 5 minutes.

Subsequent pressure tests are typically performed on hydraulic chambers only between wells or when the equipment is reassembled.

17.3.2.5 The initial pressure test on the closing unit valves, manifolds, gauges, and BOP hydraulic control lines should be to the rated working pressure of the control unit. Subsequent pressure tests of closing unit systems are typically performed following the disconnection or repair of any operating pressure containment seal in the closing unit system, but limited to the affected component.

17.3.3 PRESSURE TEST FREQUENCY

Pressure tests on the well control equipment should be conducted at least:

- Prior to spud or upon installation.
- After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, or choke manifold, but limited to the affected component.
- Not to exceed 21 days.

17.3.4 SUMMARY

Tables 1 and 2 include a summary of the recommended test practices for surface BOP stacks and related well control equipment.

17.3.5 TEST FLUIDS

Well control equipment should be pressure tested with water. Air should be removed from the system before test pressure is applied. Control systems and hydraulic chambers should be tested using clean control system fluids with lubricity and corrosion additives for the intended service and operating temperatures.

17.3.6 PRESSURE GAUGES

Pressure gauges and chart recorders should be used and all testing results recorded. Pressure measurements should be made at not less than 25 percent nor more than 75 percent of the full pressure span of the gauge.

17.3.7 TEST DOCUMENTATION

The results of all BOP equipment pressure and function tests shall be documented and include, as a minimum, the

testing sequence, the low and high test pressures, the duration of each test, and the results of the respective component tests.

- Pressure tests shall be performed with a pressure chart recorder or equivalent data acquisition system and signed by pump operator, contractor's tool pusher, and operating company representative.
- Problems observed during testing and any actions taken to remedy the problems should be documented.
- Manufacturers should be informed of well control equipment that fails to perform in the field. (Refer to API Specification 16A.)

17.3.8 GENERAL TESTING CONSIDERATIONS

Rig crews should be alerted when pressure test operations are to be conducted and when testing operations are underway. Only necessary personnel should remain in the test area.

- Only personnel authorized by the well site supervisor should go into the test area to inspect for leaks when the equipment involved is under pressure.
- Tightening, repair, or any other work is to be done only after pressure has been released and all parties have agreed that there is no possibility of pressure being trapped.
- Pressure should be released only through pressure-release lines.
- All lines and connections that are used in the test procedures should be adequately secured.
- All fittings, connections and piping used in pressure testing operations shall have pressure ratings greater than the maximum anticipated test pressure.

Verify the type, pressure rating, size, and end connections for each piece of equipment to be tested, as documented by permanent markings on the equipment or by records that are traceable to the equipment.

When a BOP stack is tested on the wellhead, a procedure should be available to monitor pressure on the casing should the test plug leak.

If the control system regulator circuit is equipped with hydro-pneumatic regulators, a backup supply is recommended to pilot the regulators in case the rig air supply is lost. Functional tests of the control system should include a simulated loss of power to the control unit and to the control panel.

Vertical stack alignment should be checked and flange bolt make-up should be torqued to prescribed ratings established in API Specification 6A.

If hydrogen sulfide bearing formations are anticipated, manufacturer's certification for compliance with NACE Standard MR0175 should be available and reviewed for well control equipment, as described in Section 20.

Table 1—Recommended Pressure Test Practices, Land and Bottom-Supported Rigs

Initial Test (prior to spud or upon installation):

Component to be Tested	Recommended Pressure Test— Low Pressure, psi ^a	Recommended Pressure Test— High Pressure, psi ^{b,c}
1. Rotating Head	200-300 (1.38 - 2.1 MPa)	Optional
2. Diverter Element	Minimum of 200 (1.38 MPa).	Optional
3. Annular Preventer	200-300 (1.38 - 2.1 MPa)	Minimum of 70% of annular BOP working pressure.
• Operating Chambers	N/A	Minimum of 1500 (10.3 MPa).
4. Ram Preventers		
• Fixed Pipe	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Variable Bore	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Blind/Blind Shear	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Operating Chamber	N/A	Maximum operating pressure recommended by ram BOP manufacturer.
5. Diverter Flowlines	Flow Test	N/A
6. Choke Line & Valves	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
7. Kill Line & Valves	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
8. Choke Manifold		
• Upstream of Last High Pressure Valve	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Downstream of Last High Pressure Valve	200-300 (1.38 - 2.1 MPa)	Optional
9. BOP Control System		
• Manifold and BOP Lines	N/A	Minimum of 3000 (20.7 MPa).
• Accumulator Pressure	Verify Precharge	N/A
• Close Time	Function Test	N/A
• Pump Capability	Function Test	N/A
• Control Stations	Function Test	N/A
10. Safety Valves		
• Kelly, Kelly Valves, and Floor Safety Valves	200-300 (1.38 - 2.1 MPa)	Working pressure of component.
11. Auxiliary Equipment		
• Mud/Gas Separator	Flow Test	N/A
• Trip Tank, Flo-Show, etc.	Flow Test	N/A

^aThe low pressure test should be stable for at least 5 minutes.

^bThe high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.

^cThe rig available well control equipment may have a higher rated working pressure than site required. The site-specific test requirement should be considered for these situations.

Table 2—Recommended Pressure Test Practices, Land and Bottom-Supported Rigs

Subsequent Tests (*not to exceed 21 days*):

Component to be Tested	Recommended Pressure Test— Low Pressure, psi ^a	Recommended Pressure Test— High Pressure, psi ^b
1. Rotating Head	N/A	Optional
2. Diverter Element	Optional	Optional
3. Annular Preventer <ul style="list-style-type: none"> • Operating Chambers 	200-300 (1.38 - 2.1 MPa) N/A	Minimum of 70% of annular BOP working pressure. N/A
4. Ram Preventers <ul style="list-style-type: none"> • Fixed Pipe • Variable Bore • Blind/Blind Shear • Casing (prior to running csg) • Operating Chamber 	200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) Optional N/A	Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. Optional N/A
5. Diverter Flowlines	Flow Test	N/A
6. Choke Line & Valves	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
7. Kill Line & Valves	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
8. Choke Manifold <ul style="list-style-type: none"> • Upstream of Last High Pressure Valve • Downstream of Last High Pressure Valve 	200-300 (1.38 - 2.1 MPa) Optional	Greater than the maximum anticipated surface shut-in pressure. Optional
9. BOP Control System <ul style="list-style-type: none"> • Manifold and BOP Lines • Accumulator Pressure • Close Time • Pump Capability • Control Stations 	N/A Verify Precharge Function Test Function Test Function Test	Optional N/A N/A N/A N/A
10. Safety Valves <ul style="list-style-type: none"> • Kelly, Kelly Valves, and Floor Safety Valves 	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
11. Auxiliary Equipment <ul style="list-style-type: none"> • Mud/Gas Separator • Trip Tank, Flo-Show, etc. 	Optional Flow Test Flow Test	N/A N/A

^aThe low pressure test should be stable for at least 5 minutes.^bThe high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.

17.4 DIVERTER SYSTEM

17.4.1 INSTALLATION TEST

All diverter system components shall be inspected and tested to ascertain proper installation and functioning. Simulate loss of rig air supply to the diverter control system and determine effects, if any, on the diverter system, vent line valves, and backup supply systems. The inspections and tests should include, but not be limited to:

- a. Check and verify the proper structural mounting of the annular sealing device assembly, and, if applicable, that the insert packing element is secured in place.
- b. For installations using remote operators, record hydraulic pressure and air supply pressure with the accumulator fully charged and the controls in the normal drilling position.
- c. Actuate the diverter close and open sequence with drill pipe or test mandrel in the diverter to verify control functions, proper equipment operating sequence and interlock, if applicable, and record response time(s).
- d. A pressure integrity test [200 psi (1.38 MPa) minimum] should be made on the diverter system after each installation. The tests may be made on parts of the system or on individual components of the system should certain components of the casing string or riser components not support a complete system test.
- e. Pump water or drilling fluid through the diverter system at low pressure and high flow rates and check vent line(s) for returns. Examine the entire system for leaks, excessive vibrations, and proper tie down while pumping fluid at high rates.
- f. In cold climates, the diverter vent lines shall be protected from freezing. Possible methods include flushing with anti-freeze solution, draining, insulation, and heat tracing.

17.4.2 SUBSEQUENT EQUIPMENT FUNCTION TEST

When in primary diverter service (no BOP installed), function tests should be performed on the diverter system at appropriate times, using the driller's panel to verify that functions are operable. Fluid should be pumped through each diverter vent line at appropriate times during operations to ensure that line(s) are not plugged.

Notes:

1. The low pressure test should be stable for at least five (5) minutes.
2. Flow-type tests should be sufficient to determine if leaks exist.
3. The rig's available well control equipment may have a higher rated working pressure than required. Site specific test requirements should be considered in these situations.

17.5 SURFACE BOP STACK EQUIPMENT

17.5.1 For the purpose of this section, the surface BOP stack equipment includes the wellbore pressure containing equipment above the wellhead, including the ram BOPs,

spool(s), annular(s), choke and kill valves, and choke line to the choke manifold. Equipment above the uppermost BOP is not included.

17.5.2 Unless restricted by height, the entire stack should be pressure tested as a unit.

17.5.3 Annular BOPs should be tested with the smallest OD pipe to be used.

17.5.4 Fixed bore pipe rams should be tested only on the pipe OD size that matches the installed pipe ram blocks.

17.5.5 Variable bore rams should be initially pressure tested on the largest and smallest OD pipe sizes that may be used during the well operations.

17.5.6 Blind ram BOPs and blind shear ram BOPs should not be tested when pipe is in the stack. The capability of the shear ram and ram operator should be verified with the BOP manufacturer for the planned drill string. The shear ram and preventer design and/or metallurgical differences among drill pipe manufacturers may require high closing pressures for shear operations.

17.5.7 Prior to testing each ram BOP, the secondary rod seals (emergency packoff assemblies) should be checked to ensure the seals have not been energized. Should the ram shaft seal leak during the test, the seal shall be repaired rather than energizing the secondary packing.

17.5.8 Ram BOPs equipped with ram locks should be pressure tested with ram locks in the closed position and closing pressure bled to zero. Manual locks either screw clockwise or counter-clockwise, to hold the rams closed. Hand wheels should be in place and the threads on the ram locking shaft should be in a condition that allows the locks to be easily operated.

17.5.9 The BOP elastomeric components that may be exposed to well fluids should be verified by the BOP manufacturer as appropriate for the drilling fluids to be used and for the anticipated temperatures to which exposed. Consideration should be given to the temperature and fluid conditions during well testing and completion operations.

17.5.9.1 Manufacturers' markings for BOP elastomeric components should include the durometer hardness, generic type of compound, date of manufacture, part number, and operating temperature range of the component.

17.5.9.2 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for six (6) months or longer.

17.5.10 Flexible choke and kill lines should be tested to the same pressure, frequency, and duration as the ram BOPs.

17.5.11 Verify that a properly precharged surge bottle is or can be installed adjacent to the annular preventer if contingency well control procedures include stripping operations.

17.5.12 The drill pipe test joint and casing ram test sub should be constructed of pipe that can withstand the tensile, collapse, and internal pressures that will be placed on them during testing operations.

17.6 CHOKES AND CHOKE MANIFOLDS

17.6.1 The choke manifold upstream of and including the last high pressure valves (refer to Figure 8) should be tested to the same pressure as the ram BOPs.

17.6.2 The configuration of pipes and valves downstream of the last high pressure valve varies from installation to installation. Each configuration should be verified for mechanical integrity.

17.6.3 The valves and adjustable chokes should be operated to verify smooth operation.

17.6.4 Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

17.7 ACCUMULATOR SYSTEM

17.7.1 ACCUMULATOR CLOSING TEST

The purpose of this test is to verify that the accumulator system is properly sized to support the fluid volume and pressure requirements of the BOPs on the rig. This test should be performed after the initial nipple up of the BOPs, and prior to each subsequent pressure test using the following procedure: (Refer to sample worksheets and examples in Appendix A.)

- a. Position a properly sized joint of drill pipe or a test mandrel in the BOPs.
- b. Turn off the power supply to all accumulator charging pumps (air, electric, etc.).
- c. Record the initial accumulator pressure. (The initial accumulator pressure should be the designed operating pressure of the accumulator.) Manifold and annular regulators should be set at the manufacturer's recommended operating pressure for the BOP stack.
- d. Individually close each ram BOP (excepting blind or blind/shear ram BOPs) and record the closing time. To simulate closure of the blind or blind/shear rams, open one set of the pipe rams. Closing times shall meet the response times stipulated in 12.3.2.
- e. Function the hydraulic operated valve(s) and record the time and volume required.
- f. Close the annular BOP and record the closing time.

g. Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.8 MPa) above precharge pressure.

17.8 AUXILIARY EQUIPMENT

Auxiliary equipment includes the upper and lower kelly valves, drill pipe safety valves, inside BOPs, and kelly.

17.8.1 Prior to spud or initial use, determine from the manufacturer's documentation whether kelly cocks and safety valves can be opened when rated working pressure below the valve is equalized by applying pressure from the top.

17.8.2 Verify that appropriate operating tools (wrenches, etc.) are readily available.

17.9 MUD/GAS SEPARATOR

Prior to spud, pump water or drilling fluid into the separator inlet and verify unobstructed flow from the separator or connections. If the separator is equipped with a float to regulate liquid discharge, observe that the float properly regulates liquid discharge.

17.10 INSPECTIONS

17.10.1 BETWEEN WELLS

After each well, the well control equipment should be cleaned, visually inspected, preventative maintenance performed, and pressure tested before installation on the next well. The manufacturer's test procedures, as prescribed in their installation, operation, and maintenance (IOM) manual, should be followed along with the test recommendations of Table 1. All leaks and malfunctions should be corrected prior to placing the equipment in service.

17.10.2 VISUAL INSPECTION—FLEXIBLE CHOKE AND KILL LINES

A visual external inspection of flexible choke and kill lines through the entire length of the line should include:

- a. Outer Jacket. Visually inspect to ensure that the outer jacket is intact to protect the polymeric sheath underneath from tearing and being punctured.
 - Verify that the outer jacket is properly attached at both end fittings.
 - Verify that the entire surface of the polymeric sheath is protected.
 - If any damage is noticed on the outer jacket, verify that it will not be detrimental to the polymeric sheath.
- b. Termination. Record any damage to the coating on the end-fitting, and monitor progression of damage. Facilitate repair, if necessary.

c. Connector. Particularly inspect the seal area of the connectors recording any damage and monitor progression of damage.

17.10.3 MAJOR INSPECTIONS

After every 3-5 years of service, the BOP stack, choke manifold, and diverter components should be disassembled and inspected in accordance with the manufacturer's guidelines.

Elastomeric components should be changed out and surface finishes should be examined for wear and corrosion. Critical dimensions should be checked against the manufacturer's allowable wear limits. Individual components can be inspected on a staggered schedule.

A full internal and external inspection of the flexible choke and kill lines should be performed in accordance with the equipment manufacturer's guidelines.

17.11 MAINTENANCE

17.11.1 INSTALLATION, OPERATION, AND MAINTENANCE MANUALS

Manufacturer's installation, operation, and maintenance (IOM) manuals should be available on the rig for all the BOP equipment installed on the rig.

17.11.2 CONNECTIONS

Studs and nuts should be checked for proper size and grade. Using the appropriate lubricant, torque should be applied in a criss-cross manner to the flange studs. All bolts should then be rechecked for proper torque as prescribed in API Specification 6A. When making up connections, excessive force should not be required to bring the connections into alignment.

Ring gaskets coated with a resilient material such as rubber or polytetrafluoroethylene (PTFE) should not be used. Due to the limited amount of deformation which a groove can make in a ring as it is compressed during installation, it is not recommended to reuse ring gaskets.

When making up proprietary clamp hubbed connections, the manufacturer's recommended procedure should be followed.

17.11.3 REPLACEMENT PARTS

Spare parts should be designed for their intended use by industry approved and accepted practices. After spare part installation, the affected pressure-containing equipment shall be pressure tested. Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

The original equipment manufacturer should be consulted regarding replacement parts. If replacement parts are acquired from a nonoriginal equipment manufacturer, the parts shall be equivalent to or superior to the original equip-

ment and fully tested, design verified, and supported by traceable documentation.

17.11.4 TORQUE REQUIREMENTS

Manuals or bulletins containing torque specifications should be available on the rig. As stated in 17.11.2, torque specifications and the lubricant's coefficient of friction should be considered when torquing fasteners. Deviating from the specified lubricant can alter the required torque.

17.11.5 EQUIPMENT STORAGE

When a BOP is taken out of service for an extended period of time, it should be completely washed, steam cleaned, and machined surfaces coated with a corrosion inhibitor. The rams or sealing element should be removed and the internals washed, inspected, and coated with a corrosion inhibitor. Connections should be covered with a corrosion inhibitor and protected with wooden or plastic covers. The hydraulic operating chambers should be flushed with a corrosion inhibitor and hydraulic connections plugged. For cold climates, precautions should be taken to prevent damage. The equipment should be elevated to prevent it from standing in water. The original equipment manufacturer should be consulted for any further specific details.

17.11.6 LUBRICANTS AND HYDRAULIC FLUIDS

The original equipment manufacturer should be consulted for the proper lubricants and control fluids to be used. On surface applications, a light mineral based hydraulic fluid can be used. In offshore operations, a mixture of potable water and a water soluble oil specifically formulated for this purpose is frequently used. Diesel fuel, kerosene, drilling fluid and salt water shall not be used in a BOP hydraulic control system (refer to 12.6.1).

17.11.7 WELD REPAIRS

Weld repairs on pressure containing and load bearing components shall only be performed in accordance with API Specification 16A, API Specification 6A, manufacturer's standards, or other applicable standards.

All welding of wellbore pressure containing components shall comply with the welding requirements of NACE Standard MR0175. Verification of compliance shall be established through the implementation of the repairer's written weld procedure specification (WPS) and the supporting procedure qualification (PQR). Welding shall be performed in accordance with a WPS, written and qualified in accordance with Article II of *ASME Boiler and Pressure Vessel Code*, Section IX. The original equipment manufacturer should be consulted to verify proposed weld procedures.

Field welding shall not be performed on flexible lines or end connections without prior consultation with the original equipment manufacturer.

17.11.8 MUD/GAS SEPARATOR INSPECTION AND MAINTENANCE

The rig maintenance and inspection schedule should provide for periodic nondestructive examination of the mud/gas separator to verify pressure integrity. This examination may be performed by hydrostatic, ultrasonic, or other examination methods.

17.12 QUALITY MANAGEMENT

17.12.1 PLANNED MAINTENANCE PROGRAM

A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, should be employed on each rig. Records of maintenance performed and repairs made should be maintained on file at the rig site or readily available for the applicable BOP equipment.

17.12.2 MANUFACTURERS' PRODUCT ALERTS/EQUIPMENT BULLETINS

Copies of equipment manufacturers' product alerts or equipment bulletins should be maintained at the rig site or readily available for the applicable BOP equipment.

17.13 RECORDS AND DOCUMENTATION

17.13.1 DRAWINGS

Drawings showing ram space-out and bore of the BOP stack and a drawing of the choke manifold showing the pressure rating of the components should be on the rig and maintained up to date. (Refer to Figure 19 for an example drawing.) A bill of material should accompany the equipment drawings to correctly identify the equipment and allow the procurement of correct replacement parts.

Changes to the BOP control system should be documented. A method should be established to control the drawings, ensuring that up-to-date documentation is maintained.

17.13.2 EQUIPMENT DATA BOOK AND CERTIFICATION

Equipment records such as API manufacturing documentation, NACE certification, and factory acceptance testing reports should be retained. Where required, copies of the manufacturer's equipment data book and third party certification should be available for review.

17.13.3 MAINTENANCE HISTORY AND PROBLEM REPORTING

A maintenance and repair historical file should be maintained by serial number on each major piece of equipment.

This file should follow the equipment when it is transferred. Equipment malfunctions or failures should be reported in writing to the equipment manufacturer as stated in API Specification 16A.

17.13.4 TEST PROCEDURES AND TEST REPORTS

Shop testing after major inspection or equipment weld repairs should be performed according to the manufacturer's written procedures.

17.13.5 API DOCUMENTS

Copies of appropriate API documents should be available at the rig site or readily available. For well control equipment, these should include the following:

- a. API Specification 6A, *Wellhead and Christmas Tree Equipment* (Order No. G06A17).
- b. API Specification 16A, *Drill Through Equipment* (Order No. G07240).
- c. API Specification 16C, *Choke and Kill Systems* (Order No. G07242).
- d. API Specification 16D, *Control Systems for Drilling Well Control Equipment* (Order No. G07243).
- e. API Recommended Practice 53, *Blowout Prevention Equipment Systems for Drilling Wells* (Order No. G53003).
- f. API Recommended Practice 64, *Diverter Systems Equipment and Operations* (Order No. G09302).

These API documents are available from:

American Petroleum Institute
Publications and Distribution
1220 L Street, NW
Washington, DC 20005
Telephone: 202/682-8375

18 Testing and Maintenance—Subsea BOP Stacks and Well Control Equipment

18.1 PURPOSE

The purpose for various field test programs on drilling well control equipment are to verify:

- a. That specific functions are operationally ready.
- b. The pressure integrity of the installed equipment.
- c. Control system and BOP compatibility.

18.2 TYPES OF TESTS

Test programs incorporate visual inspections, functional operations, pressure tests, maintenance practices, and drills. For purposes of this document, the following definitions are used for the basic types of tests:

Well name: _____

Date: _____

BOP Stack: _____

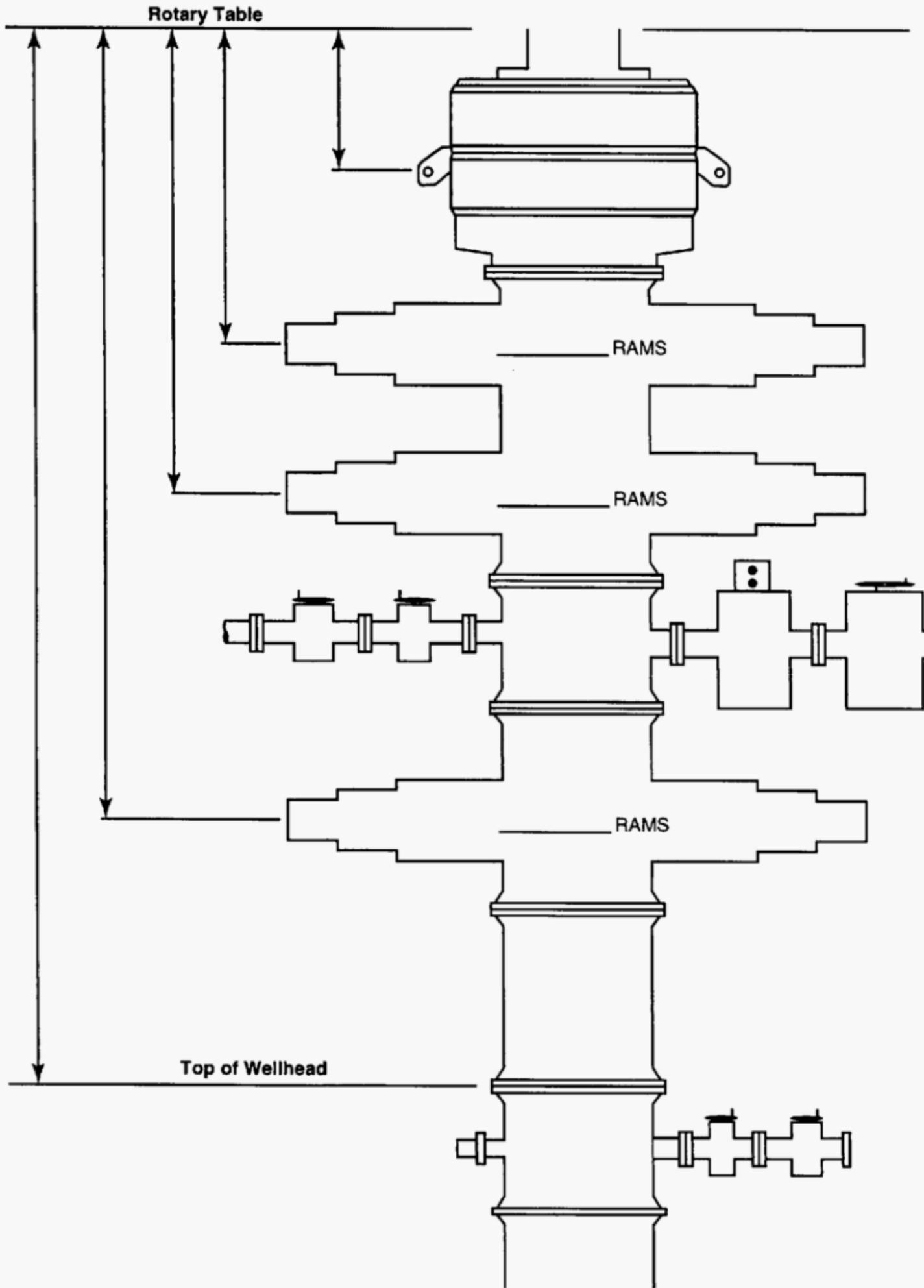


Figure 19—Example Illustration of Ram BOP Space Out

18.2.1 INSPECTION TEST

The common collective term used to state the various procedural examination of flaws that may influence equipment performance. These inspection tests may include, but are not limited to, visual, dimensional, audible, hardness, functional, and pressure tests. Inspection practices and procedures are outside the scope of this document. An example of some inspection guidelines can be found in IADC/SPE Paper 23900, *A Field Guide for Surface BOP Equipment Inspections*, W. J. Kandel and D. J. Streu, February 1992.

18.2.2 FUNCTION TEST

The operation of a piece of equipment or a system to verify its intended operation. Function testing typically does not include pressure testing. Actuation test, operating test, and readiness test are other terms commonly used synonymously for function test.

18.2.3 PRESSURE TEST

Periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system. *Wellbore test* is another descriptive term frequently used synonymously for pressure test.

18.2.4 HYDRAULIC OPERATOR TEST

The application of a pressure test to any hydraulic operated component of hydraulic-actuated equipment. Hydraulic operator tests are typically specified by the manufacturer for such items as: BOP operator cylinders and bonnet assemblies, hydraulic valve actuators, hydraulic connectors, etc. Operating chamber test is frequently used synonymously for hydraulic operator test.

Note: The definitions of test pressure, design pressure, operational characteristic tests, etc., as used in other API documents, may have meaning/intent more appropriate to manufacturing processes and the intended description may differ with field usage.

Site-specific applications of the different types of tests on well control equipment should be incorporated during field acceptance tests, initial rig-up tests, drills, periodic operating tests, maintenance practices, and drilling operations.

Note: Techniques and step-by-step or how-to-test procedures should be developed for each rig because of the varying equipment, different installation arrangements, and well-specific drilling programs. The procedure for testing the BOP stack, drill string safety valves, choke/kill lines, and manifold upstream of the buffer chamber are usually similar for most rigs.

Pressure test programs for the subsea wellhead and casing should be prescribed by the operator on an individual well basis. Manufacturer operating and maintenance documents, contractor maintenance programs, and operating experiences should be incorporated into the specific test procedures.

18.2.5 CREW DRILLS

The proficiency with which drilling crews operate the well control equipment is as significantly important as the operational condition of the equipment. Crew drills and well control rig practices are outside the scope of this document and are addressed in API Recommended Practice 59.

18.3 TEST CRITERIA

18.3.1 FUNCTION TESTS

All operational components of the BOP equipment systems should be functioned at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

- Function tests should be alternated from the driller's panel and from mini-remote panels. (Refer to sample worksheets in Appendix A.)
- Actuation times should be recorded as a data base for evaluating trends. (Refer to sample worksheets in Appendix A.)
- Release or latching type components of subsea well control systems (choke, kill, riser, wellhead connectors, etc.) and emergency backup systems are typically only functioned at the start or completion of the well.

18.3.2 PRESSURE TESTS

18.3.2.1 All blowout prevention components that may be exposed to well pressure should be tested first to a low pressure of 200 to 300 psi (1.38 to 2.1 MPa) and then to a high pressure.

- When performing the low pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure could initiate a seal that may continue to seal after the pressure is lowered therefore, misrepresenting a low pressure condition.
- A stable low test pressure should be maintained for at least 5 minutes.

18.3.2.2 The initial high pressure test on components that could be exposed to well pressure (BOP stack, choke manifold, and choke/kill lines) should be to the rated working pressure of the ram BOPs or to the rated working pressure of the wellhead that the stack is installed on, whichever is lower. Initial pressure tests are defined as those tests performed before the well is spudded (stump test) or before the equipment is put into operational service (upon landing subsea).

- Diverter systems are typically function tested only.
- Annular BOPs, with a joint of drill pipe installed, may be tested to the test pressure applied to the ram BOPs or to a minimum of 70 percent of the annular preventer working pressure, whichever is the lesser.

- The lower kelly valves, kelly, kelly cock, drill pipe safety valves, and top drive safety valves, should be tested with water from below to a low pressure of 200-300 psi (1.38 - 2.1 MPa) and to the rated working pressure.
- There may be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these should be covered in the site-specific well control pressure test program.
- Choke and kill line connections are typically tested to the working pressure of the ram BOPs while running the riser.
- The BOP-to-wellhead connector should be tested to the working pressure of the ram BOPs after landing the subsea BOP stack.
- Subsea wellhead pressure tests are typically part of the subsea stack tests and should be addressed in the site-specific well plan.

18.3.2.3 Subsequent high pressure tests on the well control components should be to a pressure greater than the maximum anticipated surface pressure, but not to exceed the working pressure of the ram BOPs. The maximum anticipated surface pressure should be determined by the operator based on specific well conditions.

Annular BOPs should be tested to a minimum of 70 percent of their working pressure or to the test pressure of the ram BOPs, whichever is less. Subsequent pressure tests are tests that should be performed at identified periods during drilling and completion activity on a well.

- A stable high test pressure should be maintained for at least 5 minutes. With larger size annular BOPs some small movement typically continues within the large rubber mass for prolonged periods after pressure is applied. This *packer creep* movement should be considered when monitoring the pressure test of the annular.
- Pressure test operations should be alternately controlled from the various onsite control stations and panels.

18.3.2.4 The initial pressure test on hydraulic chambers of annular BOPs should be to at least 1,500 psi (10.3 MPa) or higher where a subsea annular BOP requires a higher pressure for water depth and/or drilling fluid density. Initial pressure tests on hydraulic chambers of ram BOPs and hydraulically operated valves should be to the maximum operating pressure recommended by the manufacturer.

- The tests should be run on both the opening and the closing chambers.
- Pressure should be stabilized for at least 5 minutes.

Subsequent pressure tests on hydraulic chambers are typically performed between wells or when equipment is reassembled.

18.3.2.5 The initial pressure test on the closing unit valves, manifolds, gauges, and BOP hydraulic control lines should be to the rated working pressure of the control unit. Subsequent pressure tests of the closing unit system are typically performed following the disconnection or repair of any operating pressure containment seal in the closing unit system, but limited to the affected component.

18.3.3 PRESSURE TEST FREQUENCY

Pressure tests on the well control equipment should be conducted at least:

- Prior to running the BOP subsea and upon installation.
- After the disconnection or repair of any pressure containment seal in the BOP stack, choke line, choke manifold, or wellhead assembly, but limited to the affected component.
- Not to exceed 21 days.

18.3.4 SUMMARY

Tables 3 and 4 include a summary of the recommended test practices for subsea BOP stacks and related well control equipment.

18.3.5 TEST FLUIDS

Well control equipment should be pressure tested with water. Air should be removed from the system before test pressure is applied. When drilling with subsea stacks and exposed open hole, drilling fluids are normally used with subsequent tests of the subsea BOP stack to reduce the risk of an influx from hydrostatic pressure reductions. Control systems and hydraulic chambers should be tested using clean control system fluids with lubricity and corrosion additives for the intended service and operating temperatures.

18.3.6 PRESSURE GAUGES

Pressure gauges and chart recorders should be used and all testing results recorded. Pressure measurements should be made at not less than 25 percent nor more than 75 percent of the full pressure span of the gauge.

18.3.7 TEST DOCUMENTATION

The results of all BOP equipment pressure and function tests shall be documented and include, as a minimum, the testing sequence, the low and high test pressures, the duration of each test, and the results of the respective component tests.

- Pressure test shall be performed with a pressure recorder or equivalent data acquisition system and

signed by the pump operator, contractors tool pusher, and operators representative.

- Problems observed during testing and any actions taken to remedy the problems should be documented.
- Manufacturers should be informed of well control equipment that fails to perform in the field. API Specification 16A.

18.3.8 GENERAL TESTING CONSIDERATIONS

Rig crews should be alerted when pressure test operations are to be conducted. Only necessary personnel should remain in the test area.

- Only personnel authorized by the well site supervisor should go into the test area to inspect for leaks when the equipment involved is under pressure.
- Tightening, repair, or any other work is to be done only after pressure has been released and all parties have agreed that there is no possibility of pressure being trapped.
- Pressure should be released only through pressure-release lines.
- All lines, swings, and connections that are used in the test procedures should be adequately secured.
- All fittings, connections, and piping used in pressure testing operations shall have pressure ratings greater than the maximum anticipated test pressure.
- Verify the type, pressure rating, size, and end connections for each piece of equipment to be tested, as documented by permanent markings on the equipment or by records that are traceable to the equipment.
- Verify that properly precharged surge bottles are or can be installed adjacent to the annular BOPs if contingency well control procedures include stripping operations.
- The drill pipe test joint should be pipe that can withstand the tensile, collapse, and internal pressures that will be placed on it during the test operation.
- A procedure should be available to monitor pressure on the casing should the test plug leak. A weep hole in the test plug or checking the amount of test fluid used to slowly increase the test pressure are common procedures to check the test plug.
- If the control system regulator circuit is equipped with hydro-pneumatic regulators, a backup supply is recommended to pilot the regulators in case the rig air supply is lost. Functional tests of the control system should include a simulated loss of power to the control unit and to the control panel.
- If hydrogen sulfide bearing formations are anticipated the manufacturer certification for compliance with

NACE Standard MR0175 should be available for well control equipment, as described in Section 20.

18.4 DIVERTER SYSTEM

18.4.1 INSTALLATION TEST

All diverter system components shall be inspected and tested to ascertain proper installation and functioning. Simulate loss of rig air supply to the diverter control system and determine effects, if any, on the diverter system and vent line valves. Vessel motion and pressure limitation(s) of riser system components, such as flex/ball joint and telescopic (slip) joint packer, should not be overlooked during equipment installation tests. The inspections and tests should include, but not be limited to the following:

- Check and verify the proper structural mounting of the annular sealing device assembly, and, if applicable, that the insert packing element is secured in place.
- For installations using remote operators, record hydraulic pressure and air supply pressure with the accumulator fully charged and the controls in the normal drilling position.
- Actuate the diverter close and open sequence with drill pipe or test mandrel in the diverter to verify control functions, proper equipment operating sequence and interlock, if applicable, and record response time(s).
- Typically only function and flow-through tests are performed. However, an optional pressure integrity test [200 psi (1.38 MPa)] may be made on the diverter system on installation. The pressure test may be made on individual components of the system, should certain components of the casing string or riser components not support a complete system test.
- Pump water or drilling fluid through the diverter system at low pressure and high flow rates and check vent line(s) for returns. Examine the entire system for leaks, excessive vibrations, and proper tie down while pumping fluid at high rates.
- In cold climates, the diverter vent lines should be protected from freezing. Possible methods include flushing with anti-freeze solution, draining, insulation, and heat tracing.

18.4.2 SUBSEQUENT EQUIPMENT FUNCTION TEST

When in primary diverter service (no BOP installed), function tests should be performed on the diverter system at appropriate times, using the driller's panel to verify that functions are operable. Fluid should be pumped through each diverter line at appropriate times during operations to ensure that line(s) are not plugged.

Notes:

- The low pressure test should be stable for at least 5 minutes.
- Flow-type tests should be sufficient to determine if leaks exist.

Table 3—Recommended Pressure Test Practices, Floating Rigs With Subsea BOP Stacks

Initial Test (*diverter system prior to spud, et al, prior to running stack*):

Component to be Tested	Recommended Pressure Test— Low Pressure, psi ^a	Recommended Pressure Test— High Pressure, psi ^{b,c}
1. Diverter Element	Optional	Optional
2. Annular Preventer(s)	200-300 (1.38 - 2.1 MPa)	Minimum of 70% of annular BOP working pressure.
• Operating Chambers	N/A	Minimum of 1500 (10.3 MPa).
3. Ram Preventers		
• Fixed Pipe	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Variable Bore	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Blind/shear	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Operating Chambers	N/A	Maximum operating pressure recommended by ram BOP manufacturer.
4. BOP-to-WHD Connector	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
5. Diverter Flowlines	Flow Test	N/A
6. Choke & Kill Lines & Valves	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
7. Choke & Kill Manifold		
• Upstream of Last High Pressure Valve	200-300 (1.38 - 2.1 MPa)	Working pressure of ram BOPs.
• Downstream of Last High Pressure Valve	200-300 (1.38 - 2.1 MPa)	Optional
8. BOP Control System		
• Manifold	N/A	Minimum of 3000 (20.7 MPa).
• Accumulator Pressure	Verify Precharge	N/A
• Close Time	Function Test	N/A
• Pump Capability	Function Test	N/A
• Control Stations	Function Test	N/A
9. Safety Valves		
• Kelly, Kelly Valves, and Floor Safety Valves	200-300 (1.38 - 2.1 MPa)	Working pressure of the component.
10. Auxiliary Equipment	200-300 (1.38 - 2.1 MPa)	Optional
• Riser Slip Joint	Flow Test	N/A
• Mud/Gas Separator	Flow Test	N/A
• Trip Tank, Flo-Show, etc.	Flow Test	N/A

^aThe low pressure test should be stable for at least 5 minutes.^bThe high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.^cThe rig available well control equipment may have a higher rated working pressure than site required. The site-specific test requirement should be considered for these situations.

Table 4—Recommended Pressure Test Practices, Floating Rigs With Subsea BOP Stacks

Subsequent Tests [(a) BOP stack initially installed on wellhead and (b) not to exceed 21 days]:

Component to be Tested	Recommended Pressure Test— Low Pressure, psi ^a	Recommended Pressure Test— High Pressure, psi ^b
1. Diverter Element	Optional	Optional
2. Annular Preventer <ul style="list-style-type: none"> • Operating Chambers 	200-300 (1.38 - 2.1 MPa) N/A	Minimum of 70% of annular BOP working pressure. N/A
3. Ram Preventers <ul style="list-style-type: none"> • Fixed Pipe • Variable Bore • Blind/shear (initial installation) • Operating Chamber 	200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) 200-300 (1.38 - 2.1 MPa) N/A	Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. Greater than the maximum anticipated surface shut-in pressure. N/A
4. BOP-to-WHD Connector and Casing Seals	200 -300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
5. Diverter Flowlines	Flow Test	N/A
6. Choke & Kill Lines & Valves	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
7. BOP Choke Manifold <ul style="list-style-type: none"> • Upstream of Last High Pressure Valve • Downstream of Last High Pressure Valve 	200-300 (1.38 - 2.1 MPa) Optional	Greater than the maximum anticipated surface shut-in pressure. Optional
8. Control System <ul style="list-style-type: none"> • Manifold and BOP Lines • Accumulator Pressure • Close Time • Pump Capability • Control Stations 	N/A N/A Function Test Function Test Function Test	Optional N/A N/A N/A N/A
9. Safety Valves <ul style="list-style-type: none"> • Kelly, Kelly Valves, and Floor Safety Valves 	200-300 (1.38 - 2.1 MPa)	Greater than the maximum anticipated surface shut-in pressure.
10. Auxiliary Equipment <ul style="list-style-type: none"> • Riser Slip Joint • Mud/Gas Separator • Trip Tank, Flo-Show, etc. 	N/A Flow Test Optional Flow Test	N/A N/A N/A N/A

^aThe low pressure test should be stable for at least 5 minutes.

^bThe high pressure test should be stable for at least 5 minutes. Flow-type tests should be of sufficient duration to observe for significant leaks.

c. The rig's available well control equipment may have a higher rated working pressure than required. Site specific test requirements should be considered in these situations.

18.5 SUBSEA BOP STACK EQUIPMENT

18.5.1 The subsea stack equipment includes the subsea wellbore pressure containing equipment above the wellhead and below the ball/flex joint. This equipment includes the wellhead and LMRP connectors, ram BOPs, spool(s), annular(s), choke and kill valves, and choke and kill lines.

18.5.2 Unless restricted by height, the entire stack should be pressure tested as a unit.

18.5.3 Annular BOPs should be tested using the smallest OD pipe to be used.

18.5.4 Fixed bore pipe rams should be tested only on the pipe OD size that matches the installed pipe ram blocks.

18.5.5 Variable bore rams should be initially pressure tested on the largest and the smallest OD pipe sizes that may be used during the well operation.

18.5.6 Blind rams and blind shear rams should not be tested when pipe is in the stack. The capability of the shear ram and ram operator should be verified with the manufacturer for the planned drill string. The shear ram preventer design and/or metallurgical differences among drill pipe manufacturers may require high closing pressures for shear operations.

18.5.7 When drill pipe hangoff is a possibility during well control, hangoff procedures should be preplanned. The manufacturer's recommended hangoff load capacity for fixed-bore ram blocks should be considered. Example hangoff procedures are included in API Recommended Practice 59. The original ram BOP equipment manufacturer should be consulted regarding hanging off drill pipe on variable bore ram BOPs.

18.5.8 Prior to surface testing each ram BOP, the secondary rod seal (emergency packoff assembly) should be checked to ensure the seals have not been energized. Should the ram shaft seal leak during the stump test, the seal shall be repaired rather than energizing the secondary packing.

18.5.9 Ram BOPs equipped with hydraulic ram locks should be pressure tested with ram locks in the closed position and closing pressure vented.

18.5.10 The BOP elastomeric components that may be exposed to well fluids should be verified by the BOP manufacturer as appropriate for the drilling fluids to be used and for the anticipated temperatures. Consideration should be given to the temperature and fluid conditions during well testing and completion operations.

18.5.10.1 Manufacturers' markings for BOP elastomeric components should include the durometer hardness, generic

type of compound, date of manufacture, part number, and operating temperature range of the component.

18.5.10.2 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for 6 months or longer.

18.5.11 Flexible choke and kill lines should be tested to the same pressure, frequency, and duration as the ram BOPs.

18.5.12 A properly precharged surge bottle should be installed adjacent to the annular BOP if contingency well control procedures include stripping operations.

18.5.13 The drill pipe test joint and casing ram test sub should be constructed of pipe that can withstand the tensile, collapse, and internal pressures that will be placed on them during testing operations.

18.6 CHOKES AND CHOKE MANIFOLDS

18.6.1 The choke manifold upstream of and including the last high pressure valves (refer to Figure 8) should be tested to the same pressure as the ram BOPs.

18.6.2 The configuration of pipes and valves downstream of the last high pressure valve varies from installation to installation. Each configuration should be verified for mechanical integrity.

18.6.3 The valves and adjustable chokes should be operated to verify smooth operation.

18.6.4 Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

18.7 ACCUMULATOR SYSTEM

18.7.1 ACCUMULATOR CLOSING TEST

The purpose of this test is to verify that the accumulator system is properly sized to support the fluid volume and pressure requirements of the BOPs on the rig. This test should be performed prior to running the BOPs subsea and the initial landing of the stack and prior to each subsequent pressure test using the following procedures (refer to sample worksheets and examples in Appendix A):

- a. Position a properly sized joint of drill pipe or a test mandrel in the BOPs.
- b. Turn off the power supply to all accumulator charging pumps (air, electric, etc.).
- c. Record the initial accumulator pressure. (The initial accumulator pressure should be the designed operating pressure of the accumulator.) Manifold and annular regulators should be set at the manufacturer's recommended operating pressure for the BOP stack.

d. Individually close and open each ram BOP (excepting blind/shear ram BOPs), recording the closing time and fluid volume required for each function. (To simulate the functioning of the blind/shear rams, close and open one set of pipe rams again.) Closing times shall meet response times established in 13.3.5.

e. Function the hydraulic operated valves and record the time and volume required.

f. Close and open one annular BOP and record the time and volume.

g. Record the final accumulator pressure. The final accumulator pressure shall be equal to or greater than 200 psi (1.38 MPa) above precharge pressure.

18.8 AUXILIARY EQUIPMENT

Auxiliary equipment includes the upper and lower kelly valves, drill pipe safety valves, inside BOPs, and kelly.

18.8.1 Prior to spud or initial use, determine from the manufacturer's documentation whether kelly valves and safety valves can be opened when rated working pressure below the valve is equalized by applying pressure from the top.

18.8.2 Verify that appropriate operating tools (wrenches, etc.) are readily available for kelly cocks and safety valves.

18.9 MUD/GAS SEPARATOR

Prior to spud, pump water or drilling fluid into the separator inlet and verify unobstructed flow from the separator or connections. If the separator is equipped with a float to regulate liquid discharge, observe that the float properly regulates liquid discharge.

18.10 INSPECTIONS

18.10.1 BETWEEN WELLS

After each well, the well control equipment should be cleaned, visually inspected, preventative maintenance performed, and pressure tested before installation on the next well. The manufacturer's test procedures, as prescribed in their installation, operation, and maintenance (IOM) manual, should be followed along with the test recommendations of Table 3. All leaks and malfunctions should be corrected prior to placing the equipment in service.

18.10.2 VISUAL INSPECTION—FLEXIBLE CHOKE AND KILL LINES

A visual external inspection of flexible choke and kill lines through the entire length of the line should include:

a. Outer Jacket. Visually inspect to ensure that the outer jacket is intact to protect polymeric sheath underneath from tearing and being punctured.

- Verify that the outer jacket is properly attached at both end fittings.
- Verify that the entire surface of the polymeric sheath is protected.
- If any damage is noticed on the outer jacket, verify that damages would not be detrimental to the polymeric sheath.

b. Termination. Record any damage to the coating on the end-fitting, and monitor progression of damage. Facilitate repair, if necessary.

c. Connector. Particularly inspect the seal area of the connectors recording any damage and monitor progression of damage.

18.10.3 MAJOR INSPECTIONS

After every 3-5 years of service, the BOP stack, choke manifold, and diverter components should be disassembled and inspected in accordance with the manufacturer's guidelines.

Elastomeric components should be changed out and surface finishes should be examined for wear and corrosion. Critical dimensions should be checked against the manufacturer's allowable wear limits. Individual components can be inspected on a staggered schedule.

A full internal and external inspection of the flexible choke and kill lines should be performed in accordance with the equipment manufacturer's guidelines.

18.11 MAINTENANCE

18.11.1 INSTALLATION, OPERATION, AND MAINTENANCE MANUALS

Manufacturer's installation, operation, and maintenance (IOM) manuals should be available on the rig for all the BOP equipment installed on the rig.

18.11.2 CONNECTIONS

Studs and nuts should be checked for proper size and grade. Using the appropriate lubricant, torque should be applied in a criss-cross manner to the flange studs. All bolts should then be rechecked for proper torque as prescribed in API Specification 6A. When making up connections, excessive force should not be required to bring the connections into alignment.

Ring gaskets coated with a resilient material such as rubber or polytetrafluoroethylene (PTFE) should not be used. Due to the limited amount of deformation which a groove can make in a ring as it is compressed during installation, it is not recommended to reuse ring gaskets.

When making up proprietary hubbed connections, the manufacturer's recommended procedure should be followed.

Subsea BOP stacks should have each newly made up connection retorqued after it has been in service for one well to reduce the effects of bolt embedment relaxation that may have occurred.

18.11.3 REPLACEMENT PARTS

Spare parts should be designed for their intended use by industry approved and accepted practices. After spare part installation, the affected pressure-containing equipment shall be pressure tested. Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

The original equipment manufacturer should be consulted regarding replacement parts. If replacement parts are acquired from a nonoriginal equipment manufacturer, the parts shall be equivalent to or superior to the original equipment and be fully tested, design verified, and supported by traceable documentation.

18.11.4 TORQUE REQUIREMENTS

Manuals or bulletins containing torque specifications should be available on the rig. As previously stated in 18.11.2 torque specifications and the lubricant's coefficient of friction should be considered when torquing fasteners. Deviating from the specified lubricant will alter the required torque.

18.11.5 EQUIPMENT STORAGE

When a BOP is taken out of service for an extended period of time, it should be completely washed, steam cleaned, and machined surfaces coated with a corrosion inhibitor. The rams or sealing element should be removed and the internals washed, inspected, and coated with a corrosion inhibitor. Connections should be covered with a corrosion inhibitor and protected with wooden or plastic covers. The hydraulic operating chambers should be flushed with a corrosion inhibitor and hydraulic connections plugged. For cold climates, precautions should be taken to prevent damage. The equipment should be elevated to prevent it from standing in water. The original equipment manufacturer should be consulted for any further specific details.

18.11.6 LUBRICANTS AND HYDRAULIC FLUIDS

The original equipment manufacturer should be consulted for the proper lubricants and control fluids to be used. On surface applications, a light, mineral-based hydraulic fluid can be used. In offshore operations, a mixture of potable water

and a water soluble oil specifically formulated for this purpose is frequently used. Diesel fuel, kerosene, drilling fluid, and salt water shall not be used in a BOP hydraulic control system.

18.11.7 WELD REPAIRS

Weld repairs on pressure containing and load bearing components shall only be performed in accordance with API Specification 16A, API Specification 6A, manufacturer's standards, or other applicable standards.

All welding of wellbore pressure containing components shall comply with the welding requirements of NACE Standard MR0175. Verification of compliance shall be established through the implementation of the repairer's written weld procedure specification (WPS) and the supporting procedure qualification (PQR). Welding shall be performed in accordance with a WPS, written and qualified in accordance with Article II of *ASME Boiler and Pressure Vessel Code*, Section IX. The original equipment manufacturer should be consulted to verify proposed weld procedures.

Field welding shall not be performed on flexible lines or end connections without prior consultation with the original equipment manufacturer.

18.11.8 MUD/GAS SEPARATOR INSPECTION AND MAINTENANCE

The rig maintenance and inspection schedule should provide for periodic nondestructive examination of the mud/gas separator to verify pressure integrity. This examination may be performed by hydrostatic, ultrasonic, or other examination methods.

18.12 QUALITY MANAGEMENT

18.12.1 PLANNED MAINTENANCE PROGRAM

A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, should be employed on each rig. Records of maintenance performed and repairs made should be retained on file at the rig site or readily available.

18.12.2 MANUFACTURERS' PRODUCT ALERTS/EQUIPMENT BULLETINS

Copies of equipment manufacturers' product alerts or equipment bulletins should be maintained at the rig site or readily available for the applicable BOP equipment.

18.13 RECORDS AND DOCUMENTATION

18.13.1 DRAWINGS

Drawings showing ram space out and bore of the BOP stack and a drawing of the choke manifold showing the pressure rating of the components should be on the rig and maintained up to date. (Refer to Figure 20 for an example drawing.) A bill of material should accompany the equipment drawings to correctly identify the equipment and allow the procurement of correct replacement parts.

Changes to the BOP control system should be documented. A method should be established to control the drawings, ensuring that up-to-date documentation is maintained.

18.13.2 EQUIPMENT DATA BOOK AND CERTIFICATION

Equipment records such as API manufacturing documentation, NACE certification, and factory acceptance testing reports should be retained. Where required, copies of the manufacturer's equipment data book and third party certification should be retained for review.

18.13.3 MAINTENANCE HISTORY AND PROBLEM REPORTING

A maintenance and repair historical file should be retained on each major piece of equipment. This file should follow the equipment when it is transferred. Equipment malfunctions or failures should be reported in writing to the equipment manufacturer as stated in API Specification 16A.

18.13.4 TEST PROCEDURES AND TEST REPORTS

Shop testing after major inspection or equipment weld repairs should be performed according to the manufacturer's written procedures.

18.13.5 API DOCUMENTS

Copies of appropriate API documents should be available at the rig site or readily available. For well control equipment, these should include the following:

- a. API Specification 6A, *Wellhead and Christmas Tree Equipment* (Order No. G06A17).
- b. API Specification 16A, *Drill Through Equipment* (Order No. G07240).
- c. API Specification 16C, *Choke and Kill Systems* (Order No. G07242).
- d. API Specification 16D, *Control Systems for Drilling Well Control Equipment* (Order No. G07243).
- e. API Recommended Practice 53, *Blowout Prevention Equipment Systems for Drilling Wells* (Order No. G53003).

f. API Recommended Practice 16Q, *Design, Selection, Operation, and Maintenance of Marine Drilling Riser Systems* (Order No. G07249).

g. API Recommended Practice 64, *Diverter Systems Equipment and Operations* (Order No. G09302).

These API documents are available from:

American Petroleum Institute
Publications and Distribution
1220 L Street, NW
Washington, DC 20005
Telephone: 202/682-8375

19 BOP Sealing Components

19.1 FLANGES AND HUBS

API specifications for flanges and hubs, including sizes, service conditions, dimensions, and other design requirements for blowout preventers are contained in the latest edition of API Specification 6A and API Specification 16A. When flange connections are used, API flanges should be installed for BOP use. Hubs may be API or equivalent design in industry drilling service. Manufacturers should be consulted for service conditions, dimensions, and other specifications. A hub and clamp connection consists of two hubs pulled together against a metal seal ring by a two or three piece clamp. This type connection requires fewer bolts to make up and is lighter than the equivalent flanged connection.

19.2 EQUIPMENT MARKING

Marking of wellhead and Christmas tree equipment and drill through equipment should be per API Specification 6A and API Specification 16A, respectively.

19.3 RING-JOINT GASKETS

Type RX and BX ring-joint gaskets should be used for flanged and hub type blowout preventer connections in that they are self-energized type gaskets. API Type R ring gaskets are not a self-energized type gasket and are not recommended for use on well control equipment. RX gaskets are used with API Type 6B flanges and 16B hubs and BX gaskets are used with Type 6BX flanges and 16BX hubs. Detailed specifications for ring-joint gaskets are included in API Specification 6A and in API Specification 16A. Gasket materials, coatings, and platings should be in accordance with API Specification 6A. Identification markings should be in accordance with API Specification 6A, and API Specification 16A.

19.4 BOLTING

Flange and clamp stud bolt and nut specification requirements should be in accordance with API Specification 6A and

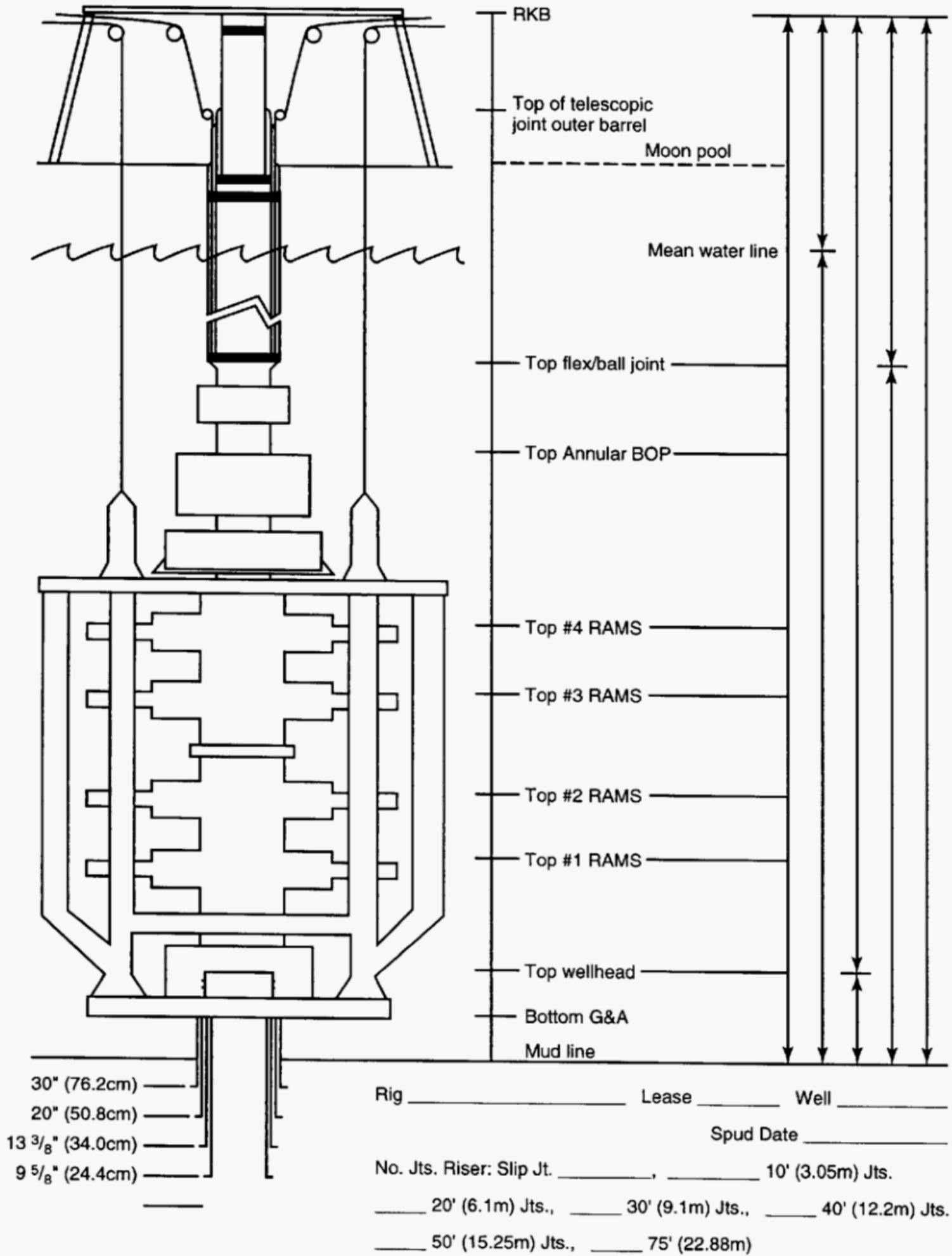


Figure 20—Example Illustration of Ram BOP Space Out

API Specification 16A. Identification marking of bolting components should be in accordance with API Specification 6A and API Specification 16A.

19.5 ELASTOMERIC COMPONENTS

Each resilient, nonwellbore, nonmetallic component, such as elastomeric seals used in BOP actuating systems, should be marked or tagged using a codification system developed by the equipment manufacturer. The marking(s) should include information regarding the durometer hardness, generic type of compound (refer to Table 5), date of manufacture (month/year), lot/serial number, manufacturer's part number, and the operating temperature range of the component. Spare BOP seals and packing units should be stored in accordance with the original equipment manufacturer's recommendations.

Note: It is important to note that some blends of drilling and completion fluids have detrimental effects on elastomer compounds. The original equipment manufacturer should be consulted regarding compatibility with drilling and completion fluids.

19.6 ELASTOMERIC COMPONENTS FOR HYDROGEN SULFIDE SERVICE

Many elastomeric components are subject to hydrogen sulfide attack. Nitrile elastomeric components that meet other job requirements may be suitable for hydrogen sulfide service provided drilling fluids are properly treated. Service life

Table 5—Elastomer Compound Marking Code
(Refer to API Specification 16A)

Common Name	Chemical Name	ASTM D-1418 Code
Butyl	Isobutylene-Isoprene	IIR
	Epichlorohydrin	CO
	Epichlorohydrin-Ethylene Oxide	ECO
Kel-F	Chloro Fluoro Elastomer	CFM
Hypalon	Chlorosulfonated Polyethylene	CSM
EPR	Ethylene-propylene Copolymer	EPM
EPT	Ethylene-propylene Terpolymer	EPDM
Viton	Fluorocarbon	FKM
Natural Isoprene:	Polyisoprene	NR
Natural or synthetic	Polyisoprene	IR
Nitrile	Butadiene-acrylonitrile	NBR
Acrylic	Polyacrylic	ACM
Diene	Polybutadiene	BR
Neoprene	Polychloroprene	CR
Vistanex	Polyisobutylene	IM
Thiokol	Polysulfide	
Silicone	Polysiloxanes	Si
SBR(GR-S)	Styrene-butadiene	SBR
Urethane	Diisocyanates	

shortens as temperature increases from 150°F to 200°F (65.6°C to 93°C). In the event flow line temperatures in excess of 200°F (93°C) are anticipated, the equipment manufacturer should be consulted. Elastomeric components should be changed out as soon as possible after exposure to hydrogen sulfide under pressure.

Changes prescribed by the primary equipment manufacturer to render equipment acceptable for service in a hydrogen sulfide environment should not be overlooked in providing for replacement and repair parts.

19.7 INTEGRAL CHOKE AND KILL LINES

Typical marine riser joints have integral choke and kill lines. This provides redundancy and allows for well control operations as follows:

- Circulating down one line and up the other line.
- Circulating down the drill pipe and up either line.

Generally, choke/kill lines and auxiliary lines of one marine riser joint are connected to their counterpart(s) on adjoining riser joints by box-and-pin, stab-in couplings. The box contains an elastomeric radial seal that expands against the smooth, abrasion-resistant sealing surface of the pin when the line is pressurized. These stab-in couplings also facilitate fast makeup while deploying the marine riser.

19.8 SUBSEA WELLHEAD CONNECTOR

The primary seal for subsea wellhead connectors is a pressure-energized, metal-to-metal type seal. Initial sealing requires that the metal seal be preloaded sufficiently to maintain contact with the mating seal surface and effect low pressure sealing capability. These seals are not recommended for re-use. Some wellhead connectors are equipped with resilient secondary seals, which may be energized should the primary seal leak. This type seal should be utilized under emergency conditions only.

19.9 MARINE RISER

The primary seal for the marine riser couplings may be elastomeric or metal-to-metal. Care should be taken to carefully clean and inspect all seals prior to running the marine riser.

The primary telescopic joint seal assembly consists of a hydraulic or pneumatic pressure-energized resilient packing element(s).

19.10 SUBSEA CONTROL SYSTEM

Primary hydraulic system seal between the male and female sections of the control pods is accomplished with resilient seals of the O-ring, pressure-energized, or face-sealing types.

The hydraulic junction boxes consist of stab subs or multiple check valve type quick disconnect couplings. The primary seals are O-rings. These O-ring seals should be inspected each time the junction box is disconnected.

The primary pod valve seals vary according to the manufacturer with both resilient and lapped metal-to-metal type seals used.

20 Blowout Preventers for Hydrogen Sulfide Service

20.1 APPLICABILITY

Where there is reasonable expectation of encountering hydrogen sulfide gas zones that could potentially result in the partial pressure of the hydrogen sulfide exceeding 0.05 psia (0.00034 MPa) in the gas phase at the maximum anticipated pressure, BOP equipment modifications should be made. Recommended safety guidelines for conducting drilling operations in such an environment can be found in API Recommended Practice 49.

20.2 EQUIPMENT MODIFICATIONS

20.2.1 Equipment modifications should be considered since many metallic materials in a hydrogen sulfide environment (sour service) are subject to a form of hydrogen embrittlement known as sulfide stress cracking (SSC). This type of spontaneous brittle failure is dependent on the metallurgical properties of the material, the total stress or load (either internal or applied), and the corrosive environment. A list of acceptable materials is given in NACE Standard MR0175.

20.2.2 A list of specific items to be changed on annular and ram type BOPs and valves for service in a hydrogen sulfide environment should be furnished by the manufacturer. As a guide, all metallic materials which could be exposed to hydrogen sulfide under probable operating conditions should be highly resistant to sulfide stress cracking.

20.2.3 The maximum acceptable hardness for all preventer and valve bodies and spools shall be in accordance with NACE Standard MR0175.

20.2.4 Ring-joint gaskets should meet the requirements of API Specification 16A and be of the material and hardness specified in API Specification 6A.

20.2.5 All bolts and nuts used in connection with flanges, clamps, and hubs should be selected in accordance with provisions of API Specification 6A.

20.2.6 All lines, crosses, valves, and fittings in the choke manifold system and the drill string safety valve should be constructed from materials meeting applicable requirements of API Specification 5L and API Specification 6A. Heat treating and other applicable requirements, as stipulated in NACE

Standard MR0175 should also be reviewed and considered. Field welding upstream of the chokes should be kept to a minimum and, if performed, should meet original shop construction standards and procedures.

20.2.7 Elastomeric components are also subject to hydrogen sulfide attack. Nitrile elastomeric components which meet other requirements may be suitable for hydrogen sulfide service provided drilling fluids are properly treated. Service life shortens rapidly as temperature increases from 150°F to 200°F (65.6°C to 93°C). In the event flowline temperatures in excess of 200°F (93°C) are anticipated, the equipment manufacturer should be consulted. Elastomeric components should be changed out as soon as possible after exposure to hydrogen sulfide under pressure.

20.2.8 Changes prescribed by the primary equipment manufacturer to render equipment acceptable for service in a hydrogen sulfide environment should not be overlooked in providing for replacement and repair parts.

21 Pipe Stripping Arrangements—Surface BOP Installations

21.1 PURPOSE

During operations on a drilling or producing well, a sequence of events may require tubing, casing, or drill pipe to be run or pulled while annulus pressure is contained by the BOPs. Such practice is called *stripping*. Stripping is normally considered an emergency procedure to maintain well control; however, plans for certain drilling, completion, or well work operations may include stripping to eliminate the necessity of loading the well with fluid.

21.2 EQUIPMENT

21.2.1 Stripping techniques vary, and the equipment required depends upon the technique employed. Each stripping operation tends to be unique, requiring adaptation to the particular circumstances. Therefore, the equipment and the basic guidelines discussed herein are necessarily general in nature. Stripping requires surface equipment which simultaneously:

- a. Permits pipe to be pulled from or run into a well.
- b. Provides a means of containing and monitoring annular pressure.
- c. Permits measured volumes of fluid to be bled from or pumped into the well.

21.2.2 To facilitate immediate stripping operations, the following should be considered:

- a. Precise measurements of the BOP spacing should be posted on the driller's control panel.
- b. Choke and kill line access locations on the BOP stack.

c. The annular regulator for the annular BOP pressure should be responsive to less than 100 psi (0.69 MPa) differential pressure. If an accumulator bottle is utilized, the bottle should be installed as close to the annular BOP as possible in the closing line and an additional bottle may be installed in the opening line. The precharge pressure of these accumulators should be determined and set for the specific rig and well conditions upon nipping up the BOPs.

d. Connections should be made from the choke manifold to the trip tank for accurate fluid volume measurements as a backup to other volume measuring systems.

21.3 PERSONNEL PREPAREDNESS

The well site supervisor and crew shall have a thorough working knowledge of all applicable well control principles and equipment employed for stripping. Equipment should be rigorously inspected, and, if practicable, operated prior to use.

21.4 SURFACE EQUIPMENT

21.4.1 For stripping operations, the primary surface equipment consists of BOPs, closing units, chokes, pumps, gauges, and trip tanks (or other accurate drilling fluid measuring equipment).

21.4.2 The number, type, and pressure rating of the BOPs required for stripping are based on anticipated or known surface pressure. Often the blowout preventer stack installed for normal drilling is suitable for low pressure stripping if spaced so that tool joints or couplings can be progressively lowered or pulled through the stack, with at least one sealing element closed to contain well pressure.

21.4.3 Annular BOPs are most commonly employed for stripping because tool joints and some couplings can be moved through the BOP without opening or closing of the packing element. High wellbore pressures may hinder the ability to allow passage of a tool joint through the closed annular BOP packing element, limiting use of these preventers in some stripping operations. To minimize wear, the closing pressure should be reduced as much as possible and the element allowed to expand and contract (breathe) as tool joints pass through. A spare packing element should be available at the well site during any stripping operation.

21.4.4 Ram type BOPs or combinations of ram and annular BOPs are employed when pressure and/or configuration of the coupling or tool joint could cause excessive wear if the annular BOP were used alone. Ram BOPs must be opened to permit passage of tool joints or couplings. When stripping between BOPs, provision should be made for pumping into and releasing fluid from the space between BOPs. Pressure across the sealing element should be equalized prior to opening the BOP to reduce wear and to facilitate operations of the BOP. After equalizing the pressure and opening the lower

BOP, a volume of drilling fluid equal to that displaced as the pipe is run into or pulled from the well should be, respectively, bled from or pumped into the space between the BOPs. To minimize wear, the closing pressure placed on ram BOPs during stripping operations should be reduced as much as possible and still maintain a seal.

21.4.5 Chokes are required to control the release of fluid while maintaining the desired annular pressure. Adjustable chokes which permit fast, precise control should be employed. Parallel chokes, which permit isolation and repair of one choke while the other is active, are desirable on lengthy stripping operations. One of the parallel chokes should be remotely operated. Because of the severe service, spare parts or spare chokes should be on location. Figure 21 illustrates one example BOP stack/choke and kill manifold installation suitable for stripping operations.

21.4.6 A pump truck or skid mounted pump is normally employed when stripping out and may be required while stripping in. The relatively small volume of drilling fluid required to replace the capacity and displacement of each stand or joint of pipe may be accurately measured and pumped at a controlled rate with such equipment. Well fluid from below the BOP should not be used to equalize pressure across the stripping BOP.

21.4.7 A trip tank or other method of accurately measuring the drilling fluid bled off, leaked from, or pumped into the well within an accuracy of one-half barrel is recommended.

21.4.8 The lowermost ram shall not be employed in the stripping operation. This ram should be reserved as a means of shutting in the well if other components of the BOP stack fail. This BOP should not be subjected to the wear and stress of the stripping process.

21.4.9 BOP control systems with associated piping and regulators are critical for stripping operations.

21.4.10 Gauges to accurately measure the annulus pressure should be used. Low range pressure gauges may be needed and should be available.

21.5 SUBSURFACE EQUIPMENT

21.5.1 Equipment which is run or set inside the pipe being stripped includes safety valves, inside blowout preventers, floats, and various plugs. The lower kelly valve, while not strictly a subsurface tool, may be run into the well.

21.5.2 Drill pipe safety valves employed for stripping are essentially full-opening valves, usually of the ball type, with outside dimensions which permit the valve to be run through the BOPs and into the well. If a well is coming in through the drill pipe, a safety valve in the open position can be stabbed into the drill pipe, then closed. Additional equipment such as

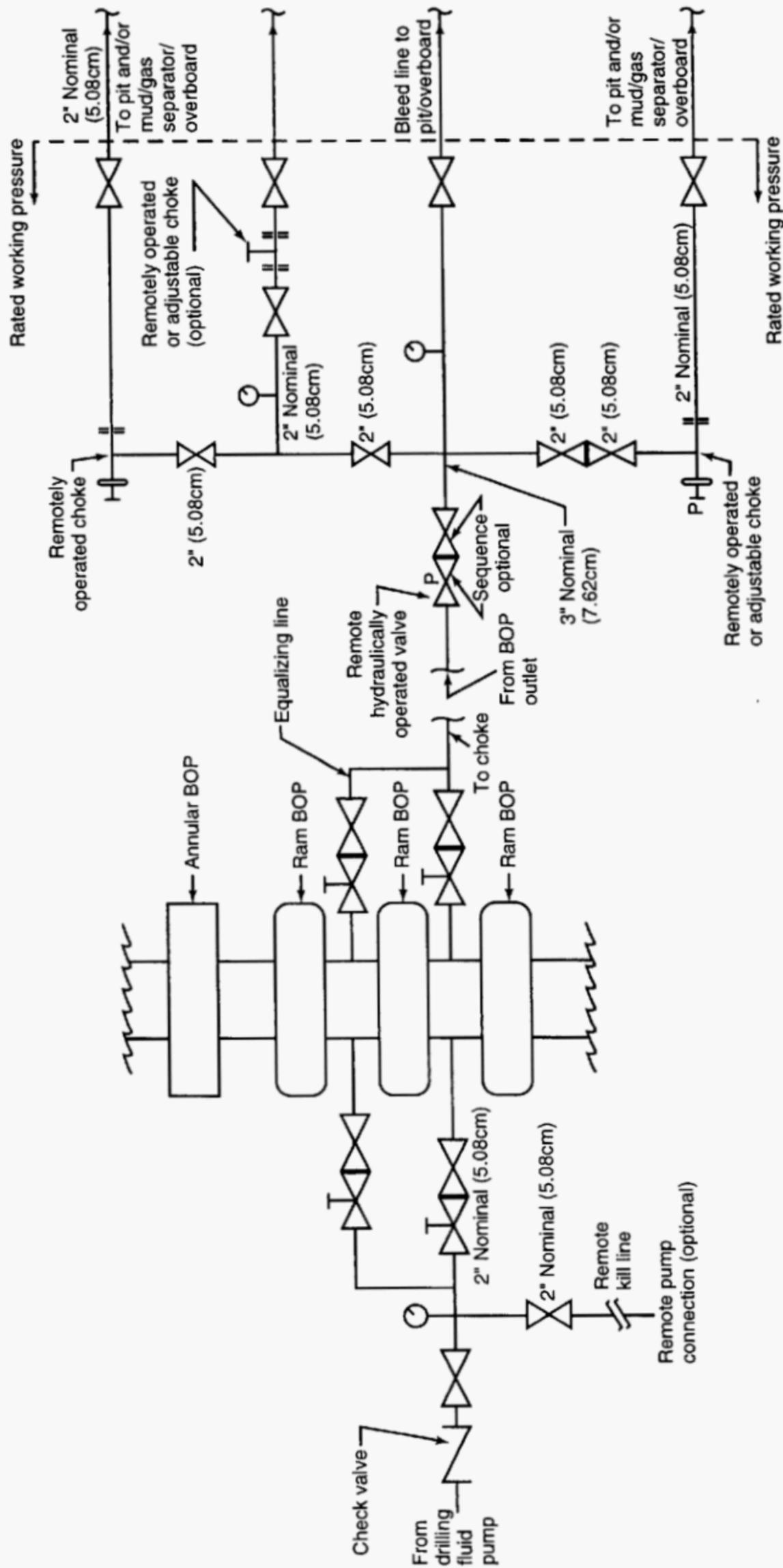


Figure 21—Example Surface BOP Stack/Choke Manifold Installation

inside blowout preventers, float valves, or seating nipples can then be installed, the safety valve opened, and run into well.

21.5.3 Inside blowout preventers can be stabbed if a well is coming in through the drill pipe or installed above a drill pipe safety valve. It should be remembered that inside blowout preventer tools may not be full-opening so that other tools cannot be run below them without a difficult milling operation.

21.5.4 Float valves can be used for stripping operations by installation above a drill pipe safety valve, or they can be run as routine items in the drill string. These tools are essentially check valves, either flapper or poppet, which seal pressure from below but permit fluid to be pumped down the drill pipe. The flapper type valves are easier to mill out and tools or pipe can be lowered through them.

21.5.5 Several types of plugs are available to effect an internal seal of the pipe being stripped. Drill pipe or tubing may be equipped with seating nipples that permit plugs to either be pumped down or run on a wireline and landed in a profile nipple, preventing flow up through the drill pipe or tubing. Some of these plugs serve as check valves, halting flow from below but permitting passage of fluid from above. Designed to be retrievable by wireline, these plugs may be removed to permit access below the seating nipple. Other nonretrievable plugs can be set in drill pipe or casing by electric or *shooting* line. Such plugs are run through pressure lubricators and set by explosive charge.

22 Pipe Stripping Arrangements—Subsea BOP Installations

22.1 PURPOSE

During operations on a drilling or producing well, a sequence of events may require tubing, casing, or drill pipe to be run or pulled while annulus pressure is contained by BOPs. Such practice is called *stripping*. Stripping is normally considered an emergency procedure to maintain well control; however, plans for certain drilling, completion, or well work operations may include stripping to eliminate the necessity of loading the well with fluid.

22.2 EQUIPMENT

22.2.1 Stripping techniques vary, and the equipment required depends upon the technique employed. Each stripping operation tends to be unique, requiring adaptation to the particular circumstances. Therefore, the equipment and the basic guidelines discussed herein are necessarily general

in nature. Stripping requires surface equipment which simultaneously:

- a. Permits pipe to be pulled from or run into a well.
- b. Provides a means of containing and monitoring annular pressure.
- c. Permits measured volumes of fluid to be bled from or pumped into the well.

22.2.2 To facilitate immediate stripping operations, the following should be considered:

- a. Precise measurements of the BOP spacing should be posted on the driller's control panel.
- b. Choke and kill line access locations on the BOP stack.
- c. The regulator for the annular BOP pressure must be responsive to less than 100 psi (0.69 MPa) differential pressure, or an accumulator should be installed in the BOP closing line and may be installed on the opening line. The precharge pressure of these accumulators should be determined and set for the specific rig and well conditions before running the BOP stack.
- d. Connections should be made from the choke manifold to the trip tank for accurate fluid volume measurements as a backup to other volume measuring systems.
- e. A heave indicator readout at the driller's position can aid in the implementation of stripping operations.
- f. Vessel motion, drill pipe motion, and well pressure constraints should be established, beyond which stripping operations should not be performed.
- g. Ram BOPs are not normally used during stripping operations involving subsea BOP installations due to complications caused by vessel motion.
- h. Crews should be aware of the potential of trapped gas under BOPs and the potential of unloading of fluid from a riser. Crews should be instructed on proper procedures of removing gas pocket accumulations from below shut in BOPs.

22.3 PERSONNEL PREPAREDNESS

The well site supervisor and crew shall have a thorough working knowledge of all well control principles and equipment employed for stripping. Equipment should be rigorously inspected, and, if practicable, operated prior to use.

22.4 EQUIPMENT AT THE SURFACE

22.4.1 For stripping operations, the primary surface equipment consists of hydraulic control unit, chokes, pumps, gauges, and trip tanks (or other accurate drilling fluid measuring equipment).

22.4.2 The number, type, and pressure rating of the BOPs required for stripping are based on anticipated or known surface pressure. Often the blowout preventer stack installed for normal drilling is suitable for low pressure stripping if spaced

so that tool joints or couplings can be progressively lowered or pulled through the stack, with at least one sealing element closed to contain well pressure.

22.4.3 Annular BOPs are most commonly employed for stripping because tool joints and some couplings can be moved through the BOP without opening or closing of the packing element. High wellbore pressures may hinder the ability to allow passage of a tool joint through a closed annular BOP packing element, limiting use of these preventers in some stripping operations. To minimize wear, the closing pressure should be reduced as much as possible and the element allowed to expand and contract (breathe) as tool joints pass through. A spare packing element should be available at the well site during any stripping operation.

22.4.4 A skid mounted pump is normally employed when stripping out and may be required while stripping in. The relatively small volume of drilling fluid required to replace the capacity and displacement of each stand or joint of pipe may be accurately measured and pumped at a controlled rate with such equipment.

22.4.5 A trip tank or other method of accurately measuring the drilling fluid bled off, leaked from, or pumped into the well within an accuracy of one-half barrel is recommended.

22.4.6 BOP control systems with associated piping and regulators are critical for stripping operations.

22.4.7 Gauges to accurately measure the annulus pressure should be used. Low range pressure gauges may be needed and should be available.

22.5 SUBSURFACE EQUIPMENT

22.5.1 Equipment which is run or set inside the pipe being stripped includes safety valves, inside blowout preventers, floats, and various plugs. The lower kelly valve, while not strictly a subsurface tool, may be run into the well.

22.5.2 Drill pipe safety valves employed for stripping are essentially full-opening valves, usually of the ball type, with outside dimensions which permit the valve to be run through the BOPs and into the well. If a well is coming in through the drill pipe, a safety valve in the open position can be stabbed into the drill pipe, then closed. Additional equipment such as inside blowout preventers, float valves, or seating nipples can then be installed, the safety valve opened, and a sealing assembly run into well.

22.5.3 Inside blowout preventers can be stabbed if a well is coming in through the drill pipe or installed above a drill pipe safety valve. It should be remembered that inside blowout preventer tools may not be full-opening so that other tools cannot be run below them without a difficult milling operation.

22.5.4 Float valves can be used for stripping operations by installation above a drill pipe safety valve, or they can be run as routine items in the drill string. These tools are essentially check valves, either flapper or poppet, which seal pressure from below but permit fluid to be pumped down the drill pipe. The flapper type valves are easier to mill out and tools or pipe can be lowered through them.

22.5.5 Several types of plugs are available to effect an inside seal of the pipe being stripped. Drill pipe or tubing may be equipped with seating nipples that permit plugs to either be pumped down or run on a wireline and landed in a profile nipple, preventing flow up through the drill pipe or tubing. Some of these plugs serve as check valves, halting flow from below but permitting passage of fluid from above. Designed to be retrievable by wireline, these plugs may be removed to permit access below the seating nipple. Other nonretrievable plugs can be set in drill pipe or casing by electric or *shooting* line. Such plugs are run through pressure lubricators and set by explosive charge.

APPENDIX A—FORMS

SUBSEA ACCUMULATOR FUNCTION TEST WORKSHEET

Rig Name: _____ Date: _____ By: _____

Pod: Blue Station: _____ Pod: Yellow Station: _____
 Close Open Close Open

Function	Time, sec	Vol, gal	Time, sec	Vol, gal	Time, sec	Vol, gal
U. Annular	_____	_____	_____	_____	_____	_____
L. Annular (BSR)	_____	_____	_____	_____	_____	_____
Lower Pipe Ram	_____	_____	_____	_____	_____	_____
Middle Pipe Ram	_____	_____	_____	_____	_____	_____
Upper Pipe Ram	_____	_____	_____	_____	_____	_____
U.O. Kill	_____	_____	_____	_____	_____	_____
U.I. Kill	_____	_____	_____	_____	_____	_____
L.O. Kill	_____	_____	_____	_____	_____	_____
L.I. Kill	_____	_____	_____	_____	_____	_____
U.O. Choke	_____	_____	_____	_____	_____	_____
U.I. Choke	_____	_____	_____	_____	_____	_____
L.O. Choke	_____	_____	_____	_____	_____	_____
L.I. Choke	_____	_____	_____	_____	_____	_____
WH Conn	_____	_____	_____	_____	_____	_____
LMRP Conn	_____	_____	_____	_____	_____	_____

Does the accumulator system function the ram and annular BOPs within the proper time limits?
 Each ram BOP in less than 45 sec _____ Yes _____ No _____
 Each annular BOP in less than 60 sec _____ Yes _____ No _____

If yes, the system is functioning properly. If no, the system is in need of maintenance and/or repair.

Note: Closing and opening time should be measured from the moment the function is activated to the moment the read back pressure gauge returns to its full operating pressure.

SUBSEA ACCUMULATOR CLOSING TEST WORKSHEET

Rig Name: _____ Date: _____ By: _____

PUMP SETTINGS

Electric pumps turn on at _____ psi; turn off at _____ psi. Air pumps turn on at _____ psi; turn off at _____ psi.
 Charging pumps: _____ minutes to charge system from minimum operating pressure to full accumulator working pressure
 (≤ 15 minutes per 13.4.1 and 14.3.1 respectively).
 Initial accumulator pressure: _____ psi. Surface accumulator precharge pressure: _____ psi.
 Subsea accumulator precharge pressure: _____ psi.

PUMP SETTINGS

<u>Function</u>	<u>Time, sec</u>	<u>Volume Required, gal</u>	<u>Remaining Pressure, psi</u>	<u>Opening Time, sec</u>	<u>Volume Required, gal</u>	<u>Remaining Pressure, psi</u>	<u>Final Pressure</u>
Lower Pipe Ram	_____	_____	_____	_____	_____	_____	_____
Middle Pipe Ram	_____	_____	_____	_____	_____	_____	_____
Upper Pipe Ram	_____	_____	_____	_____	_____	_____	_____
Blind/Shear Rams*	_____	_____	_____	_____	_____	_____	_____
Upper Annular	_____	_____	_____	_____	_____	_____	_____

*Substitute functioning the upper pipe ram a second time for functioning the blind rams.

<u>Function</u>	<u>Opening Time, sec</u>	<u>Volume Required, gal</u>	<u>Remaining Pressure, psi</u>
U.I. Choke Valve	_____	_____	_____
U.O. Choke Valve	_____	_____	_____
L.I. Choke Valve	_____	_____	_____
L.O. Choke Valve	_____	_____	_____
U.I. Kill Valve	_____	_____	_____
U.O. Kill Valve	_____	_____	_____
L.I. Kill Valve	_____	_____	_____
L.O. Kill Valve	_____	_____	_____

ACCUMULATOR PRESSURE

Is the final pressure equal to or greater than 200 psi (1.38 MPa) above precharge pressure? Yes _____ No _____

CLOSING TIME

Closing times should be recorded during each test to be used as an indicator of possible problems that could occur in subsequent tests. The times for the drill cannot be used to determine the actual closing times during normal operations due to the reduced operating pressure that the system has after the first and all succeeding functions have occurred.

SURFACE ACCUMULATOR CLOSING TEST WORKSHEET

Rig Name: _____ Date: _____ By: _____

PUMP SETTINGS

Electric pumps turn on at _____ psi; turn off at _____ psi. Air pumps turn on at _____ psi; turn off at _____ psi.
 Charging pumps: _____ minutes to close annular on smallest size pipe used (≤ 2 minutes per 12.4.1).
 Initial accumulator pressure: _____ psi. Surface accumulator precharge pressure: _____ psi.

ACCUMULATOR CLOSING TEST

<u>Function</u>	<u>Time, sec</u>	<u>Remaining Pressure, psi</u>
Lower Pipe Ram	_____	_____
Middle Pipe Ram (if applicable)	_____	_____
Upper Pipe Ram	_____	_____
Blind Ram*	_____	_____
Annular	_____	_____
HCR Valve (open)	_____	Final Pressure

*Substitute functioning the upper pipe ram a second time for functioning the blind rams.

ACCUMULATOR PRESSURE

Is the final pressure equal to or greater than 200 psi (1.38 MPa) above precharge pressure? _____ Yes _____ No

CLOSING TIME

Closing times should be recorded during each test to be used as an indicator of possible problems that could occur in subsequent tests. The times for the drill cannot be used to determine the actual closing times during normal operations due to the reduced operating pressure that the system has after the first and all succeeding functions have occurred.

Does the accumulator system function the rams and annulars within the proper time limits?

Each ram BOP in less than 30 sec _____ Yes _____ No
 Each annular BOP in less than 30 sec for $<18\frac{3}{4}$ " and 45 sec for $18\frac{3}{4}$ " and greater _____ Yes _____ No

If yes, the system is function properly. If no, the system is in need of maintenance and/or repair.

Note: Closing times should be measured from the moment the function is activated to the moment the readback pressure gauge returns to its full operating pressure.

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