Ballot 6744

Well Control Systems for Well Servicing

API XXXX 16WS
FIRST EDITION, XXXX 202X

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Introduction

Well control equipment systems are designed with components that provide wellbore pressure control in support of well operations. To the extent that this document recommends specific equipment arrangements, it is recognized that other arrangements can be equally effective in addressing well requirements and achieving safety and operational efficiency.

1 Scope

This document contains procedures for the installation and testing of blowout prevention equipment systems on land for well servicing rigs working in a cased well. Its purpose is to provide the means to contain well fluids to the wellbore, add fluids to the wellbore, and allow controlled fluid volumes to be removed from the wellbore. This document does not include the following:—Coil Tubing BOP's (see API 16ST)

The following components are included in the scope of this document for operations under varying rig and well conditions:

— blowout preventers (BOPs);

— injection and circulating lines;

— injection and circulating manifolds;

— accumulator systems;

— auxiliary equipment.

This document does not include the following:

— diverters, shut-in devices, and rotating head systems (rotating control devices) (see API 64 and API 16RCD, respectively); their primary purpose is to safely divert or direct flow rather than to contain fluids to the wellbore;

— procedures and techniques for well control.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Specification 6A, *Specification for Wellhead and Tree Equipment*

API Specification 7K, *Drilling and Well Servicing Equipment*

API Specification 16A, *Specification for Drill-through Equipment*

API Specification 16C, *Choke and Kill Equipment*

API Specification 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

ASME B1.20.1, *Pipe Threads, General Purpose (Inch)*

ASME B31.3, *Process Piping*

ASME *Boiler and Pressure Vessel Code (BPVC), Section IX: Welding and Brazing Qualifications*

NACE MR0175/ISO 15156 (all parts), *Petroleum and natural gas industries—Materials for use in H_2S containing environments in oil and gas production*

3 Terms, Definitions, and Abbreviations

For the purposes of this recommended practice, the following terms and definitions apply.

3.1 Terms and Definitions

3.1.1
accumulator fluid
Hydraulic oil, water-based fluid, or inert gas/nitrogen that, under pressure, pilots the operation of accumulator valves or directly operates functions

3.1.2
accumulator system
A system of pressure vessels charged with inert gas bladders used to store and distribute hydraulic fluid under pressure to remotely operate individual BOPE components.

3.1.3
adapter spool
Spool used to connect drill-through equipment with different end connections, nominal size designations, or pressure ratings to each other.

3.1.4
annular blowout preventer
Blowout preventer that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or an open hole.

3.1.5
auxiliary equipment
Supplemental equipment used for well containment or well control.

NOTE Includes drill pipe or tubing safety valves, kelly valves, flare/vent lines, power swivels, and circulating swivels.

3.1.6
accumulator remote control
Actuator panel containing an array of switches, push buttons, lights, valves, pressure gauges, and/or meters used to control or monitor functions, pressures, and alarms.

3.1.7
articulated pipe
Rigid pipe, swivel unions, and end connectors, designed to accommodate specified relative movement between end terminations.

3.1.8
barrier element
A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed.

3.1.9
bleed line
panic line
blow down line
Flow line on the circulating manifold that bypasses the chokes, as needed

3.1.10
blind ram
Closing and sealing component in a ram BOP that seals the wellbore when no tubulars are present

3.1.11
blind shear ram
BSR
Closing and sealing component in a ram BOP that first shears certain tubulars in the wellbore and then seals off the well bore or acts as a blind ram if there are no tubulars in the wellbore.

3.1.12
blowout
Uncontrolled flow of well fluids and/or formation fluids from the wellbore to the surface or into lower-pressured subsurface zones (underground blowout).

3.1.13
blowout preventer
BOP
Sealing ram or annular type device, installed on the wellhead or wellhead assemblies to contain wellbore fluids in the annular space between the casing and the tubulars or in a well bore with no tubulars present.

NOTE BOPs are not gate valves, diverters, rotating heads, rotating control devices, rotating circulating devices, capping stacks, snubbing or stripping packages, or non-sealing rams ; BOPs are workover/ intervention control packages, well control components.,..

3.1.14
blowout preventer equipment
BOPE
Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars, or in an open hole during well drilling operations. In well servicing operations this includes circulating lines and components.

3.1.15
BOP stack
Equipment within the scope of API 16A and API 16C that is connected to the top of the wellhead.

3.1.16
blowout preventer equipment system
BOP stack including the equipment and accumulator

3.1.17
cased well
A well that has been cased with steel pipe and cemented in place.

3.1.18
choke
Device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas.

3.1.19
choke, kill, and circulating equipment
Equipment within the scope of API 16C installed on the BOP stack, circulating kill manifold, and between the BOP and circulating kill manifold.

3.1.20
circulating lines
High-pressure line(s) that allow fluid to be pumped into or removed from the well with the BOPs closed.

3.1.21
circulating kill manifold
Assembly of valves, chokes (as needed), gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.

3.1.22
circulating system
The complete, circuitous path that the workover or drilling fluid travels.

NOTE Starting at the main rig pumps, major components include surface piping, flow control valves, manifolds, the standpipe, the Kelly hose (rotary), the drill pipe, tubing, bottom hole assembly, the various annular geometries of the casing strings, the flowline, the fluid tanks or pits, the centrifugal precharge pumps, and, finally, returning to the positive displacement main rig pumps.

3.1.23
competent person
Person with characteristics or abilities gained through training, experience, or both, as measured against the manufacturer's or equipment owner’s established requirements, and with the authority to take action to address recognized hazards.

3.1.24 elastomeric seal
Seal that comes in contact with wellbore fluids (e.g. annular packers, ram block seals, operator rod or stem seals, valve seats, etc.).

3.1.25
drilling spool
Pressure-containing component having end connections and outlets that is used below or between BOPE .

3.1.26
original equipment manufacturer
(OEM)
current equipment manufacturer
(CEM)
Design owner of the traceable assembled equipment, single equipment unit, or component part.

NOTE If any alterations to the original design and/or assembled equipment or component part are made by anyone other than the OEM, then the assembly, part, or component is not considered an OEM product. The party that performs these alterations is then designated as the CEM.

3.1.27
equipment owner
Purchaser or renter of the equipment to be installed on the wellhead.

3.1.28
equipment user
Company that owns the well, wellhead, or wellhead assemblies on which the equipment is to be installed.

NOTE This entity may also be the equipment owner in cases where the equipment is rented from a third-party supplier, in part or wholly, depending on the level of equipment supplied.

3.1.29
full opening safety valve
FOSV
Valve with unobstructed flow area dimensionally equal to or greater than the nominal size designation used to control flow up the drill pipe or tubing string.

3.1.30
full opening valve
Valve with unobstructed flow area dimensionally equal to or greater than the nominal size designation.

3.1.31
function test
Operation of a piece of equipment or a system to verify its intended operation.

3.1.32
flexible line
A flexible hose or articulated pipe assembly used to convey high-pressure workover or drilling liquids within the circulating system.

The assembly of a pipe body and end-fittings.

NOTE 1 The pipe body comprises a combination of materials that form a pressure–containing conduit.

NOTE 2 The pipe structure allows large deflections without a significant increase in bending stresses.

3.1.33
hydraulic power unit
HPU
A power unit and pump used to supply hydraulic fluid under pressure.

3.1.34
hydrogen sulfide
H_2S
Highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon-bearing formations.

3.1.35
hydrostatic pressure
Pressure that is exerted at any point in the wellbore due to the weight of the column of fluid above that point.

3.1.36
incompatible wellbore fluid
Well control fluid that can damage elastomers within the BOPE or circulating system due to corrosive or solvent effects.

3.1.37
initial test pressure
API pressure designation that is equal to or above well program MASP for a land BOP system.

NOTE See Table 1 for API pressure designations.

3.1.38
inspection test
Examination or procedure that determines the existence of flaws that can influence equipment performance.

3.1.39
kelly valve
Full open valve installed immediately below the power swivel that can be closed to confine pressures inside the drill string or tubing

3.1.40
kick
Unintended influx of formation liquids or gas into the wellbore.

NOTE Without corrective measures, this condition can result in a blowout.

3.1.41
maintenance
Disassembly, inspection, reassembly, replacement of components, and/or testing of equipment performed in accordance with the equipment owner's maintenance program and the manufacturer's guidelines.

NOTE This can include, but is not limited to: inspections, cleaning, polishing, function testing, pressure testing, NDE, and change out of those parts defined in the maintenance system to be changed either periodically or on the basis of their condition.

3.1.42
maintenance system
A system used to schedule and document preventive/planned maintenance activities and document corrective maintenance associated with rig equipment.

3.1.43
maximum anticipated operating pressure
MAOP
The highest calculated pressure that a given equipment component will be subjected to during the execution of the prescribed service and/or during a contingency operation.

3.1.44
maximum anticipated surface pressure
MASP
Highest surface pressure predicted to be encountered while the well control equipment is installed. Provided to the rig crew from the customer.

3.1.45
minimum operator pressure for low-pressure seal
MOPFLPS
BOP operator pressure required to affect a low-pressure wellbore seal when closing against zero initial wellbore pressure.

3.1.46
pipe ram
Closing and sealing component in a ram BOP that seals around the outside diameter of a tubular in the cased wellbore.

3.1.47
pressure test
Application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system.

3.1.48
quill/stem
The rotating tubular assembly that is the primary flow path for fluid through a power swivel below the gooseneck and packing assembly.

3.1.49
rated working pressure
RWP
Maximum internal pressure that equipment is designed to contain or control.

3.1.50
repair
Replacement of parts or correction of damaged or worn components that does not include machining, welding, heat treating, or other manufacturing operation.

3.1.51
remanufacture
Activity involving disassembly, reassembly, and testing of equipment where machining, welding, heat treating, or other manufacturing operations are employed.

3.1.52
spacer spool
Spool used to provide separation between two components with equal-sized end connections.

3.1.53
stable
State in which the pressure change rate has decreased to within documented acceptance criteria.

3.1.54
wellbore fluids
Fluids used in workover of wells to provide primary well control of subsurface pressures by a combination of density and any additional pressure acting on the fluid column (annular or surface imposed).

3.1.55
well servicing well control barrier
A tested mechanical device, or combination of tested mechanical devices, or hydrostatic barrier elements capable of preventing uncontrolled flow of wellbore effluents to the surface.

3.1.56
well control equipment
Equipment within the scope of API 16A, API 16C, API 16D, and the supporting auxiliary equipment referenced in the scope of this document.

3.1.57
well servicing
Work done to the well after the well construction is completed.

3.1.58
well servicing rig
A mobile rig designed to perform well work needed throughout the life cycle of the well

3.1.59
workfloor Isolation Valve
A ball valve or other pressure tested valve adapted to be used only to secure the tubing string against flow in PC-0 well conditions.

3.2 Abbreviations

For the purposes of this standard, the following abbreviations apply.

BOP	blowout preventer
BOPE	blowout preventor equipment
BSR	blind shear ram
CEM	current equipment manufacturer
HPU	hydraulic power unit

H_2S	hydrogen sulfide
ID	inside diameter
IOM	installation, operation, and maintenance
MASP	maximum anticipated surface pressure
MOC	management of change
MOP	minimum operating pressure
MOPFLPS	minimum operator pressure for low-pressure seal
OEC	other end connections
OEM	original equipment manufacturer
OD	outside diameter
PDTP	pre-deployment test pressure
RCFA	root cause failure analysis
RWP	rated working pressure
SME	subject matter expert
VBR	variable-bore ram
WPS	weld procedure specification

4 Cased Hole Well Containment Equipment

4.1 General

Well servicing well control equipment is designed to allow safe well completion, workover, and maintenance services to be performed. The selection of well control equipment for a given application should be consistent with the manufacturers' recommendations.

4.2 Well Servicing Operations

4.2.1 General

4.2.1.1 Well control equipment shall be identified, installed, tested, and used to promote and maintain control of the well at all times.

4.2.1.2 The following well servicing operations shall be reviewed and understood: :

a) maximum anticipated surface pressure (MASP);

b) maximum anticipated operating pressure (MAOP);

c) well control barriers;

d) operational pressure categories;

e) well control stack configurations;

f) bore size, rated working pressure (RWP), and connections of well control equipment.

4.2.2 Well Control Barriers

4.2.2.1 General

Barrier elements can be classified as either physical or operational.

4.2.2.2 Physical Barrier Elements

Physical barrier elements can be classified as hydrostatic, mechanical or solidified chemical materials (usually cement).

4.2.2.3 Hydrostatic Barrier Elements

4.2.2.3.1 Hydrostatic barrier elements are those in which a column of fluid(s) imposes a hydrostatic pressure that exceeds the pore pressure of the potential flow zone. These fluids can include drilling fluids, cement spacers, cement slurries, produced water, hydrocarbons and completion fluids. It is important to understand that the hydrostatic contribution of any of these fluids can change with time.

4.2.2.3.2 A decrease in the height of the fluid column due to downhole losses can compromise the hydrostatic barrier element and should be taken into account in the planning stages of the operation.

4.2.2.3.3 Tested mechanical barrier elements incorporated in the well control stack or bottomhole assembly (BHA), and full opening safety valves shall demonstrate reliable and repeatable pressure and flow control performance through mechanical testing prior to being used for the prescribed service.

4.2.2.3.4 The minimum number of barriers required for a specific operation shall be determined by the well operator.

4.2.2.3.5 Wellheads with no tubing hanger, such as Larkin-style heads, are common in producing wells and do not allow for the setting of a barrier plug (mechanical barrier) prior to nipple up or nipple down. In these cases, a single hydrostatic fluid barrier is the operational well control barrier for the task.

4.2.2.3.6 Cased hole, producing wells, or cased hole wells undergoing completion operations range from wells with low bottom hole pressure that cannot support a column of fluid (wells that go on “vacuum”) to wells that will hold a full column of fluid to surface or produce pressure to surface.

4.2.2.3.7 A risk assessment shall be performed to determine the ability of the well to accept a mechanical barrier or a hydrostatic barrier alone.

4.2.2.3.8 The well operator shall determine whether a well-specific or field-based risk assessment is appropriate.

4.2.2.3.9 Wells that cannot maintain a column of fluid but can have an influx resulting in pressure at surface may be controlled with a calculated hydrostatic value. In well servicing this is referred to as a top kill. The initial top kill is then followed by ongoing injection/trickling of fluid at a predetermined rate (dynamic well condition) into the wellbore to maintain the equilibrium/no flow condition at surface.

4.2.2.3.10 Nipple down and nipple up operations should not be authorized where a standalone hydrostatic barrier does not prevent unassisted flow.

4.2.2.3.11 The following mechanical devices, or combination of mechanical devices, are well servicing well control barriers once verified:

a) the combination of a pipe ram sealing component, casing or tubing work string and a full opening safety valve assembly that can be installed within the casing or tubing

b) a tubing hanger plug, check valve or sealing wrap around with full opening safety valve (FOSV)

c) a shear-blind ram (SBR) for specific operating conditions.

NOTE The full opening safety valve assembly installed in the end of the casing or tubing work string in combination with a pipe ram sealing component in the well control stack constitutes only one barrier, regardless of the number of pipe ram sealing devices installed in the well control stack. In the pressure categories where multiple pipe rams or annular preventers are recommended in the well control stack, these do not constitute an increase in the number of barriers in the stack.

4.3 Operational Pressure Categories

4.3.1 BOP equipment is based on RWP and designated as described in Table 1.

Table 1 —Surface BOP Pressure Designations

Pressure Designation	**Rated Working Pressure (RWP)** psi (MPa)
2K	2000 (13.79)
3K	3000 (20.68)
5K	5000 (34.47)
10K	10,000 (68.95)
15K	15,000 (103.42)

4.3.2 Minimum stack RWP should be selected to allow for a kill program to be implemented. The difference between the MASP and minimum stack pressure rating in Table 1 is a recommended pressure margin.

4.3.3 Every installed ram BOP shall have an RWP greater than or equal to the MASP to be encountered.

Table 2 – Pressure Categories for Well Servicing (Cased Hole) Well Control Equipment

Pressure Category (PC)	**MASP Range** psig	**Minimum Rated Working Pressure of Stack** [b] psig	**Minimum Number of Barriers**	**Minimum Number of Closures in Stack**
PC-0	[a]	3000	1	2
PC-1	< 3000	3000	2	2
PC-2	3001 to 5000	5000	2	2
PC-3	5001 to 10000	10000	2	3
PC-4	10001 to 15000	15000	2	4
[a] PC-0 applies to wells demonstrated as incapable of unassisted flow to surface (based on local regulatory guidelines or well operator requirements).				
[b] The minimum RWP of the stack shall be equal to or greater than the MAOP or MASP.				

4.3.4 The kill procedure plan shall include implementation of one or more of the following:

a) bullheading;

b) circulation method;

c) lubricating and bleeding technique;

d) flowing or blowing down the well to reduce surface pressure or pumping at lower rates to minimize friction pressure.

NOTE MAOP or MASP which exceeds the limits of Pressure Category (PC) 4 are beyond the scope of this document.

4.4 Well Control Stack Configurations

4.4.1 General

4.4.1.1 The configuration of the well control stack can vary depending upon many factors, including, but not limited to, MAOP, MASP, pipe string design, and execution of the prescribed service.

4.4.1.2 A risk assessment shall be performed by the well operator and be communicated to the equipment user, and equipment owner, for all classes of BOP stack arrangements to identify ram configuration, outlet placements, and choke and kill valve configurations. including capillary strings, electric cables, and control or tech lines, test tools, etc. (see Figure 1 for example configuration.)

4.4.1.3 The well operator shall determine whether a well specific or field-based risk assessment is appropriate.

4.4.2 Surface BOP Stack Risk Assessment for BSRs

4.4.2.1.1 For PC-3 and PC-4 BOP stack arrangements, the well owner shall conduct a risk assessment to determine if a BSR is required. The risk assessment may cover multiple wells drilled in similar fields or geological formations.

4.4.2.1.2 The assessment in 4.4.2.1.1 shall include the following elements:

a) proximity to an environmentally sensitive area;

b) H_2S radius of exposure;

c) proximity to populated areas;

d) kick risks and planned mitigations;

e) well control responses for all drill pipe, tubing in use, and other equipment run in the well;

f) analysis of the rig equipment and well control systems capabilities and limitations for the proposed operations;

g) wells with limited subsurface data;

h) flow potential;

i) simultaneous operations;

j) the shearing capability of the rams is sufficient to shear and seal the well bore based on the pipe in the well or well work program.

4.4.3 Shearing Pipe and Other Operational Considerations

4.4.3.1 Any identified well-specific risk(s) associated with the use of the BOP equipment and systems shall be mitigated and/or managed through the development of specific guidelines, operational procedures, and a risk assessment.

4.4.3.2 Due to the variations in pipe properties and corresponding shear pressures, the maximum expected pressure for shearing pipe should be less than 90 % of the maximum operating pressure of the shear ram actuator.

NOTE It is important to understand the effects of wellbore pressure and its impact on the capability of shearing the drill pipe when the annular preventer is closed (see Table B.1).

4.4.3.3 An additional risk assessment should be performed if the shear pressure is higher than 90 % of the maximum operating pressure of the shear ram actuator or the control system.

NOTE Shearing capabilities can be determined by calculations or actual shear data for the pipe, BOP type, and configuration.

4.4.3.4 If the BSR is used to shear pipe, the ram block shall be inspected, and the BOP tested as soon as operations allow.

4.4.4 Pressure Categories 0–4

The arrangement of well control stack equipment for Pressure Categories 0 through 4 (see Table 1) shall be in accordance with Table 2; refer to the text for specific details. Example illustrations of well control stack options are provided in Annex A.

Table 3 – Well Servicing Well Control Stack Equipment Configuration

Equipment Working Pressure Rating in PSI	No Flow	<3000	3001 to 5000	5001 to 10000	10001 to 15000
Well control equipment component	PC-0	PC-1	PC-2	PC-3	PC-4
Total Number of Closures	2	2	2	4	5
Blind ram	1 Required	1 Required	1 Required	1 Required	1 Required
Shear capable ram	Optional	Optional	Optional	1 Required	1 Required
Pipe ram	1 Required	1 Required	1 Required	2 Required	3 Required
Annular preventer	Optional	Optional	Optional	1 Required	1 Required
Work Floor Isolation Valve*	Required	Not applicable	Not applicable	Not applicable	Not applicable
Full opening safety valve	Optional	Required	Required	Required	Required
Second FOSV	Optional	Optional	Recommended	Required	Required
Kill line inlet connection	Optional	Optional	Optional	Required	Required
Hydraulic control valve	Optional	Optional	Optional	Required	Required
Choke manifold (refer to Table 3)	Optional	Optional	Optional	Required	Required (hydraulically controlled chokes)
Hydraulic control (accumulator)	Optional	Required	Required	Required	Required
Single power source and pump - manually controlled.	Optional	Required	Not recommended	Not recommended	Not recommended
Dual power source and pumps with (1)pump automatic start and stop and (1) pump manually start and automatic stop	Optional	Optional	Required	Not recommended	Not recommended
Dual power source and pump with automatic start and stop on each	Optional	Optional	Recommended	Required	Required
Low pressure alarm (audible and visual) - at the accumulator	Optional	Optional	Optional	Required	Required
Accumulator remote control	Optional	Optional	Optional	Recommended	Required

* - A Work Floor Isolation Valve may be used in leu of a FOSV on PC-0 wells

Table 4 – Well Servicing Choke-Kill Manifold Configuration

Equipment Component	PC-0	PC-1	PC-2	PC-3	PC-4
Choke and kill outlet location	Between or below rams or in drilling spool	Between or below rams or in drilling spool	Between or below rams or in drilling spool	Between or below rams or in drilling spool	Between rams
Valve type and size	2 in. or larger gate/ball/plug	2 in. or larger gate/ball/plug	2 in. or larger gate/ball/plug	3 in. or larger gate	3 in. or larger gate
Line connection type	Threaded - flanged / hammer union	Threaded - flanged / hammer union	Flanged / hammer union	Flanged	Flanged
Choke manifold valves	Two manual gate/ball/plug	Two manual gate/ball/plug	Two manual gate/ball/plug	One manual and one hydraulic gate	Two hydraulic gates
Kill valves	Two manual gate/ball/plug	Two manual gate/ball/plug	Two manual gate/ball/plug	One manual and one hydraulic gate	Two hydraulic gates

4.5 BOP Stack Classifications

4.5.1 General

4.5.1.1 The quantity of pressure containment sealing components in the vertical wellbore of a BOP stack (total number of ram and annular preventers) shall be used to identify the classification or "class" for the BOP system installed. For example, a Class 6 stack designation indicates a stack with a combination of six ram and/or annular preventers installed (e.g. two annular and four ram preventers or one annular and five ram preventers).

NOTE After the classification of the BOP stack has been identified, the next nomenclature identifies the quantity of annular-type preventers installed and designated by an alphanumeric designation (e.g. A2 identifies that two annular preventers are installed).

4.5.1.2 The final alphanumeric designation shall be assigned to the quantity of rams or ram cavities, regardless of their use, installed in the BOP stack.

4.5.1.3 The rams or ram cavities shall be designated with an "R" followed by the numeric quantity of rams or ram cavities. (e.g. R4 designates that four ram-type preventers are installed).

EXAMPLE A Class 6 BOP stack installed with two annular-type and four ram-type preventers is designated as "Class 6-A2-R4".

4.5.2 Adapter/Spacer Spools

4.5.2.1 Spacer spools may be used to allow additional space between preventers, as needed

4.5.2.2 Adapter and spacer spools shall

a) have a minimum vertical bore diameter equal to the internal diameter of the mating equipment, and

b) have an RWP (rated working pressure) equal to or greater than the lowest RWP of the mating equipment, and

c) have no penetrations capable of exposing the wellbore to the environment.

4.5.3 Drilling Spools

4.5.3.1 Circulating lines should 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.

4.5.3.2 Utilization of the ram-type BOP side outlets reduces the number of stack connections and overall BOP stack height. However, a drilling spool may be used to provide stack outlets (to localize possible erosion in the dispensable spool) and to allow additional space between preventers, as needed.

4.5.3.3 Drilling spools for BOP stacks shall have the following:

a) two side outlets no smaller than a 2 in. (5.08 cm) nominal size;

b) a vertical bore diameter equal to the internal diameter of the mating BOPs and at least equal to the maximum bore of the uppermost wellhead or wellhead assembly;

c) an RWP equal to the RWP of the installed ram BOP above the spool.

4.5.3.4 For drilling operations, wellhead or wellhead assembly outlets shall not be employed for choke or kill lines.

4.5.4 Land BOP Stack Arrangements

4.5.4.1 The system shall provide a means to perform the following:

a) close and seal on the drill pipe, tubing, casing, or liner and allow circulation;

b) close and seal on open wellbore and allow volumetric well control operations;

c) strip the drill string or tubing string if an annular is installed

d) shear the drill pipe or tubing when BSRs are installed;

e) circulate across the BOP stack to a circulating manifold.

4.5.4.2 Annular preventers having one API class lower RWP, than ram preventers shall be acceptable.

4.5.4.3 Rig-specific stack-identifying nomenclature (circulating lines, rams, annulars, etc.) shall be made part of the well servicing program.

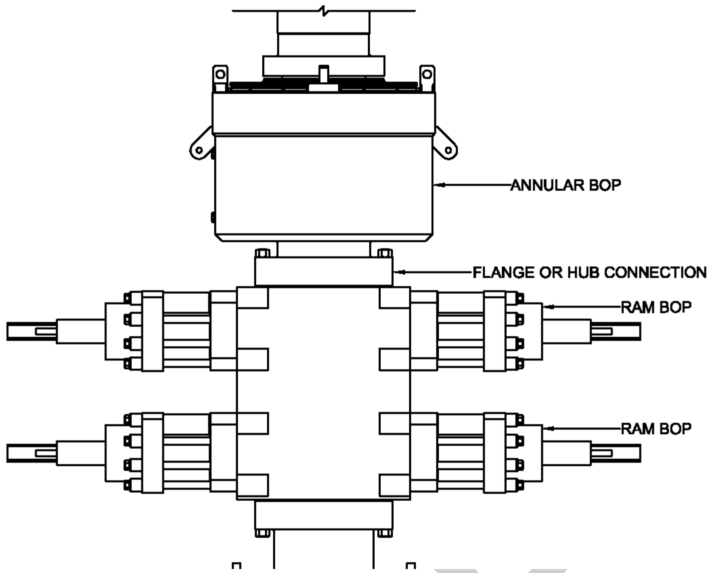


Figure 1 —Example Well Servicing Rig Land BOP

4.5.4.4 A minimum of a PC-1 BOP stack arrangement with one blind ram or BSR shall be installed for wells with a MASP of 3000 psi or less.

4.5.4.5 A minimum of a PC-2 BOP stack arrangement with one blind ram or BSR and one pipe ram shall be installed for wells with a MASP of greater than 3000 psi to 5000 psi.

4.5.4.6 A minimum of a PC-3 BOP stack arrangement with one annular, one blind ram or BSR, and two pipe rams shall be installed for wells with a MASP of greater than 5000 psi to 10,000 psi.

4.5.4.7 A minimum of a PC-4 BOP stack arrangement with one annular, one BSR, and three pipe rams shall be installed for wells with a MASP of greater than 10,000 psi.

4.5.4.8 Sealing ram-type preventers shall be equipped with locking devices.

4.6 Pressure Containment Equipment

4.6.1 Circulating Systems Pressure Designations

4.6.1.1 Depending on operations, surface BOP circulating systems shall provide access points to the BOP stack and allow for well containment operations as follows.

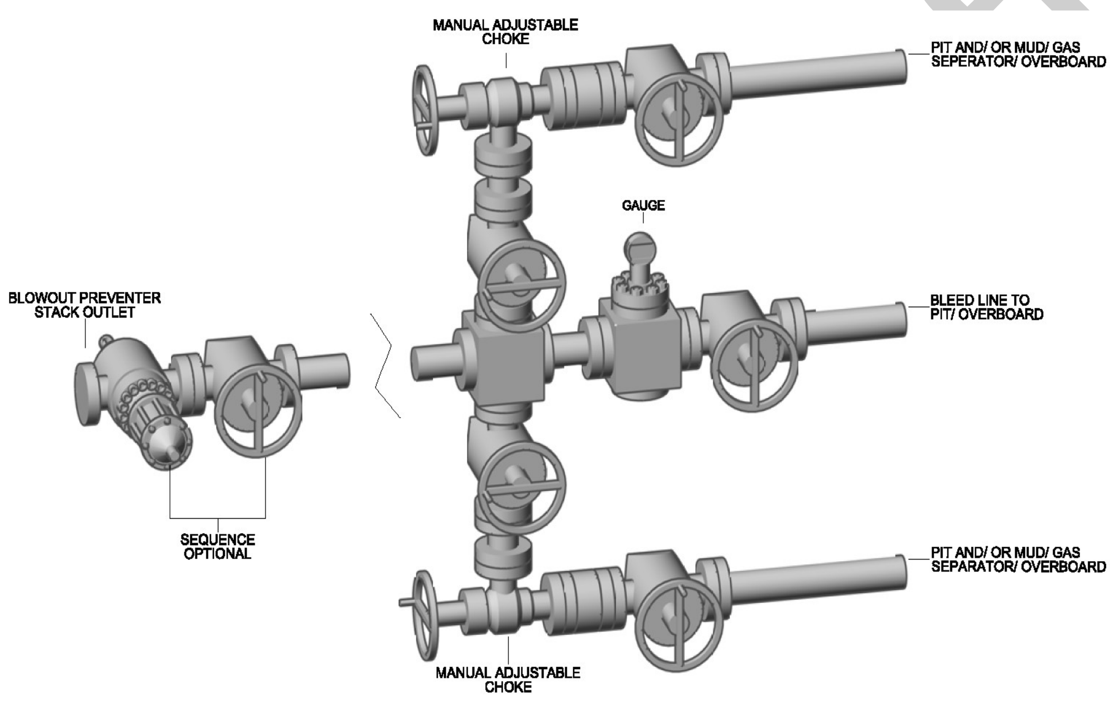
a) Circulating down the tubing, drill pipe or other tubular and up the annulus of the casing or liner.

b) Pump/bullhead down the tubing, drill pipe or other tubular. The wellhead valve shall not be used as a control valve. A secondary valve shall be placed on the wellhead valve to use as a control valve.

c) Allow well pressure monitoring.

4.6.1.2 BOP or drilling spool outlet(s) connected to the circulating line shall have two fully opening valves that shall not be used for throttling.

4.6.1.3 A throttling valve or choke should be installed downstream of the BOP or drilling spool outlet valves. See Figure 4.



NOTE For applicability and marking requirements for hammer unions refer to API 7HU.

Figure 2—Example 5K RWP Choke Line and Choke Manifold

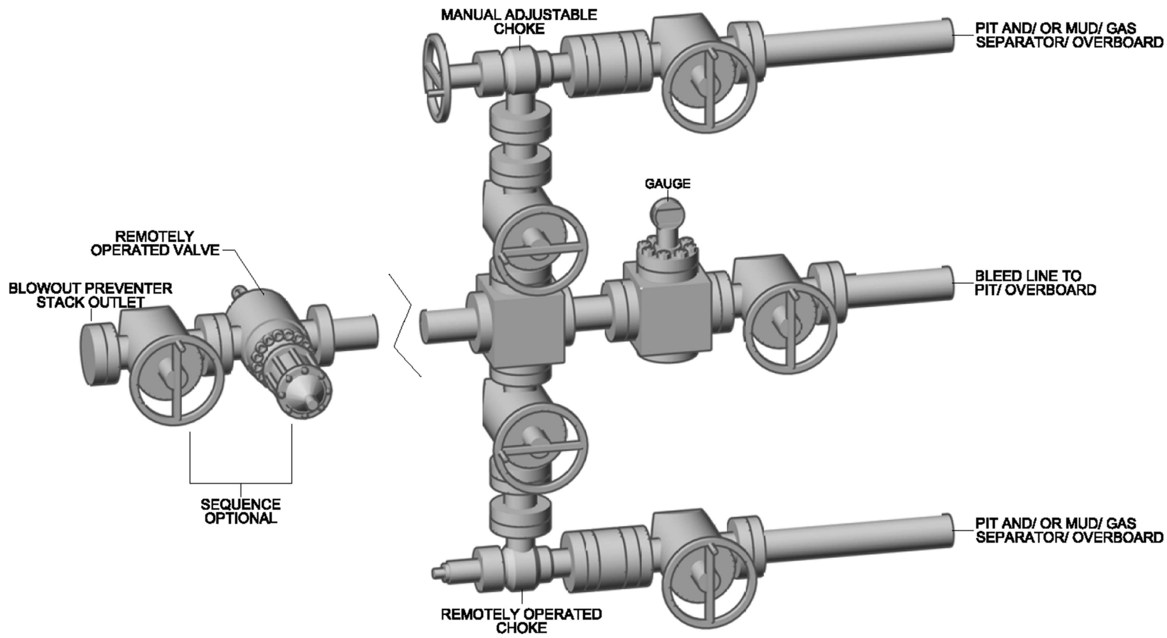


Figure 3—Example 5K to 10K RWP Choke Line and Choke Manifold

4.6.1.4 Wells with an MASP greater than 5000 psi shall, at a minimum, consist of a circulating line configuration with two full-bore manual valves plus a check valve, or two full-bore valves, one of which is remotely operated. (See Figure 6, Figure 7, and Figure 8 for kill line examples.)

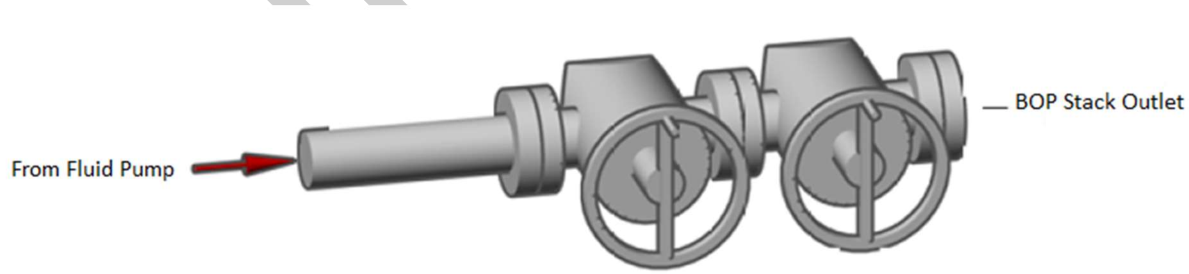


Figure 4—Example Less than 5K RWP Kill Line

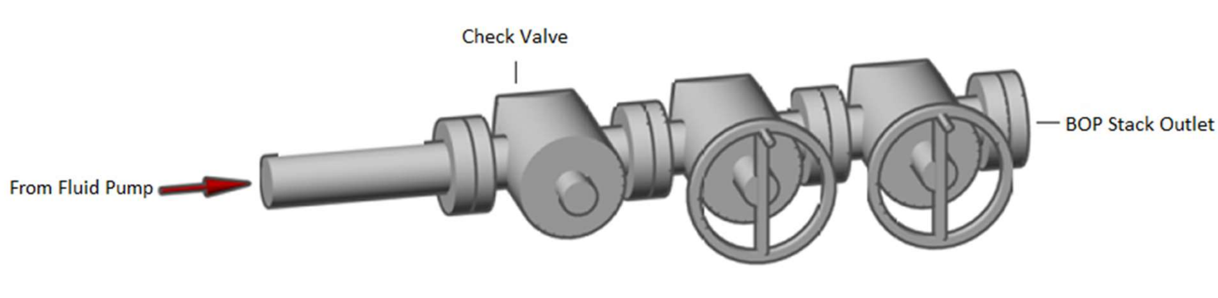


Figure 5—Example Greater than 5K to 10K RWP Kill Line

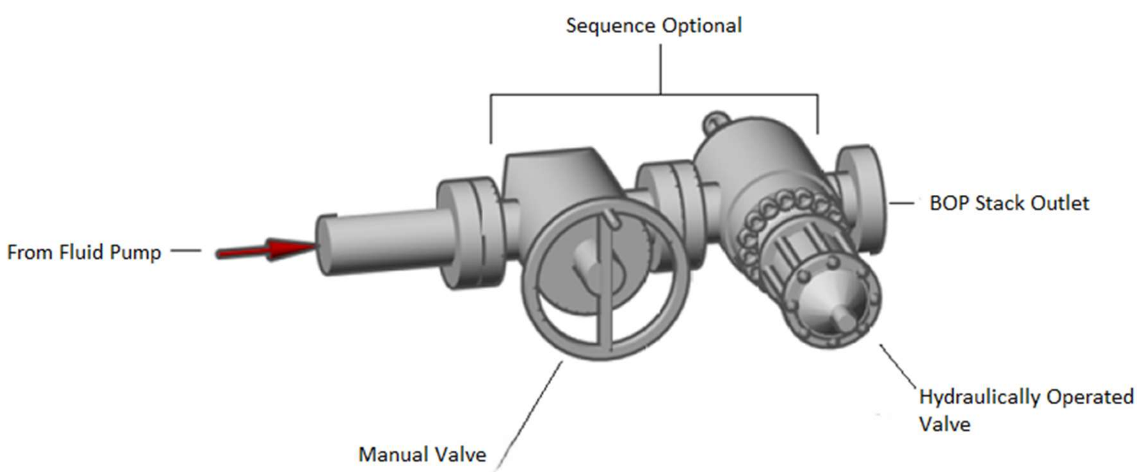


Figure 6—Example 10K or Greater RWP Kill Line

4.6.1.5 Wells with an MASP of 5000 psi (34.47 MPa) or less shall, at a minimum, consist of a kill line configuration with two full-bore manual operated valves.

NOTE Consider using a check valve in the kill line configuration for wells where H_2S is expected.

4.6.1.6 If a remote kill line is used, it should be connected to the kill line near the BOP stack and extended to an auxiliary high-pressure pump at a safe location.

4.6.2 Specifications for Pressure Containment Equipment

4.6.2.1 Choke lines, choke line valves and manifold components pressure containment equipment shall be in accordance with the edition of API 6A that was in effect at the time of manufacture.

4.6.2.2 The latest edition of API 6AR should be used for modifications, remanufactured equipment, or replacement equipment.

4.6.2.3 Modifications, alterations, or adjustments from the original design or intent of the circulating system shall be documented through the use of the equipment owner's MOC system.

4.6.2.4 Circulating lines shall be installed using rigid piping, articulated, or flexible lines. See Figure 1 and Figure 2 as examples of circulating line assemblies used in well servicing operations.

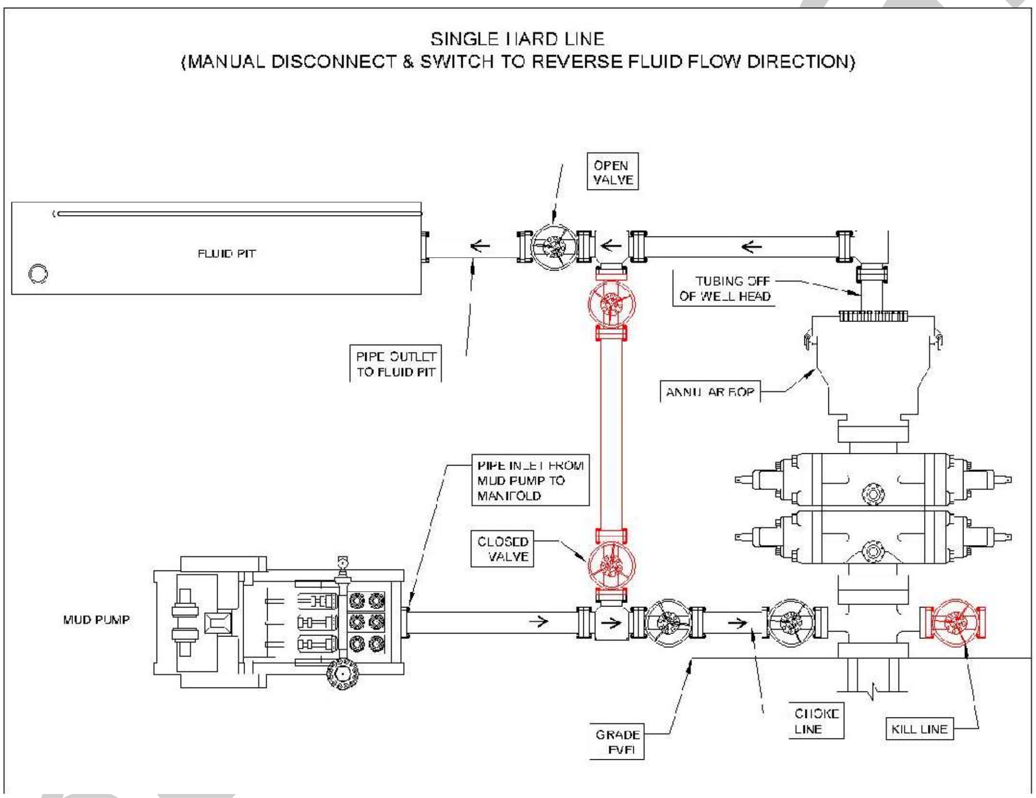
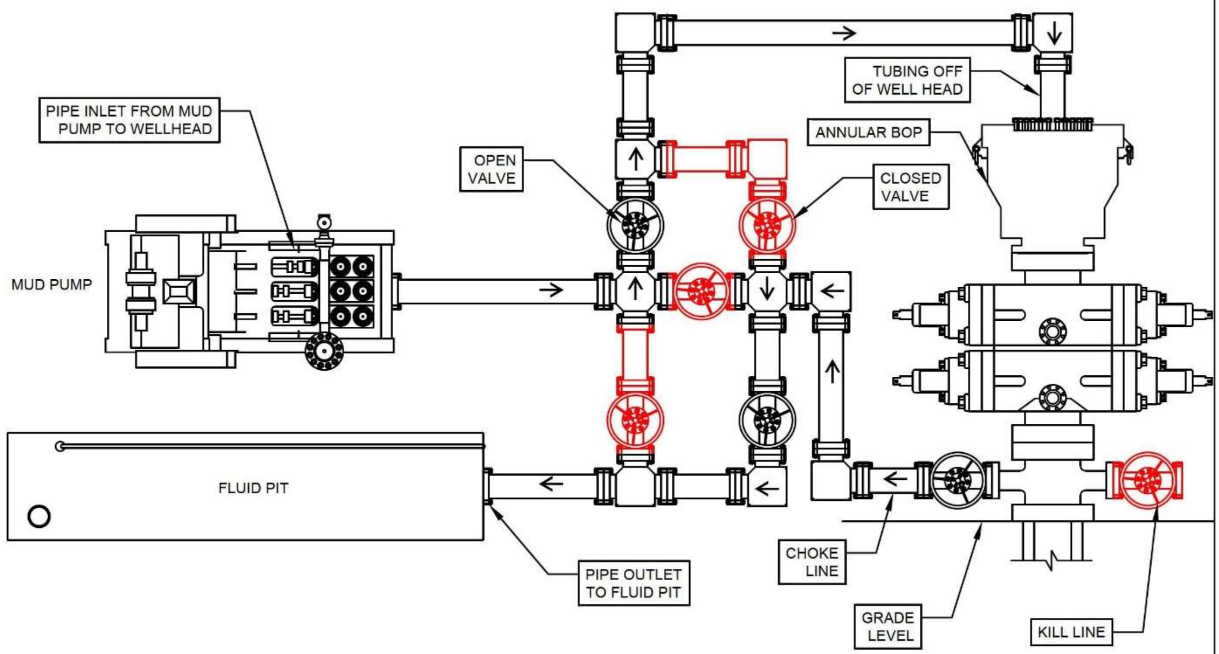


Figure 7 – Well Service Pump Circulation System Without Manifold

DOUBLE HARD LINE
(5 VAVLE CIRCULATING MANIFOLD FORWARD CIRCULATING



DOUBLE HARD LINE
(5 VAVLE CIRCULATING MANIFOLD REVERSE CIRCULATING

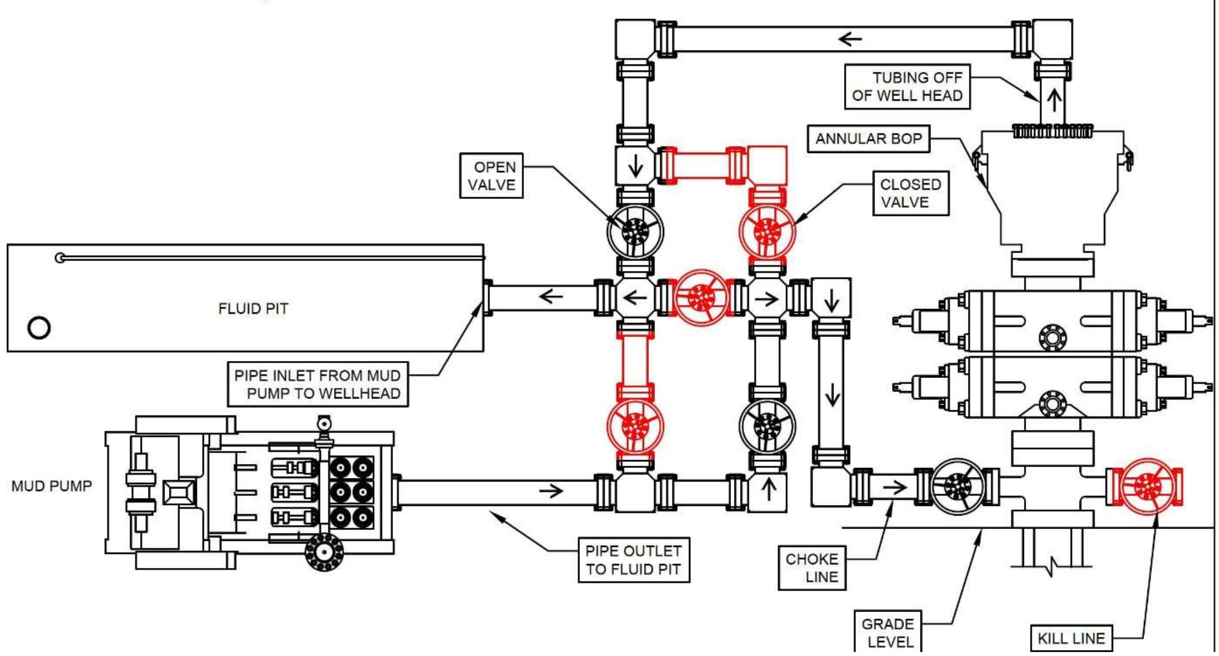


Figure 8 – Well Service Pump Circulation System With Manifold

4.6.2.5 Pressure containment equipment shall meet the area classification requirements for the area in which it is installed.

NOTE See API 500 and API 505 for information on electrical area classification.

4.6.2.6 For systems operating in temperatures where freezing can occur, the circulating manifold and pressure piping shall be protected from freezing.

4.6.2.7 Pressure piping and components shall be inspected for wear, damage, and erosion and pressure tested annually.

4.6.2.8 If a component is used to connect the BOP or drilling spool outlet to the valves, the equipment owner's maintenance system shall include an inspection of the component for erosion annually.

4.6.3 Circulation Manifold Equipment

4.6.3.1 A risk assessment should be performed on the basis of well pressure, likelihood of flow, or presence of hazardous gas to determine the pressure rating and connection types for circulating/manifold equipment

4.6.3.2 A circulating manifold and a choke line (where applicable) are components temporarily installed to perform the well intervention operations and provide a means to control pressure and flow originating from the wellbore, well control stack, or both. The circulating manifold includes, but is not limited to, piping, fittings, connections, valves, pressure monitoring device(s) and adjustable choke(s).

4.6.3.3 If a by-pass line is installed in the choke manifold, the by-pass line shall be equipped with at least two full-opening valves.

NOTE A by-pass line is a pressure-containing branch of the choke line manifold which redirects fluid flow upstream of the choke(s) and provides a means for unchoked flow to the atmosphere.

4.6.3.4 When used, choke manifold components should be installed in accordance with the following:

4.6.3.5 Manifold equipment subject to well or pump pressure, or both (normally upstream of and including the chokes) shall have a RWP equal to or greater than the MASP of the well.

4.6.3.6 For all pressure categories, at least one full-opening valve shall be installed between the choke line and each adjustable choke. Full-opening choke line valves shall not be used to throttle or choke flow.

4.6.3.7 In a multi-choke manifold, two full-opening valves shall be installed between the choke line and each choke device when it is expected that repairs may be conducted on one choke while flowing through the alternate choke.

4.6.3.8 For operations where the MASP exceeds 10,000 psi, the adjustable chokes and their adjacent inboard valve shall be remotely controlled.

4.6.3.9 Pressure monitoring device(s) should be installed so that tubing, wellbore, and/or choke pressure(s) can be monitored.

4.6.3.10 For wells with a MASP of less than 3000 psi (20.7 MPa), circulating system components shall have a rated working pressure of at least 3000 psi.

4.6.3.11 For wells with a MASP (maximum anticipated surface pressure) of 3000 psi (20.7 MPa) and greater, flanged, welded, or integral joint hammer unions shall be used. NPT and LPT threaded connections may be used in accordance with Table 5.

Table 5 – Pressure Rating for internal Threaded End or Outlet Connectors

Type of Thread	**Nominal Sizes of Pipe, Tubing, or Casing** **in.**	**Rated Working Pressure** psi (MPa)
NPT	½	10,000 (69.0)
	¾ to 1 ½	5000 (34.5)
Line pipe	½	10,000 (69.0)
	¾ to 2	5000 (34.5)
	2 ½ to 6	3000 (20.7)
Tubing, nonupset, and external upset round thread	1.050 to 4 ½	5000 (34.5)
Casing (8 round, buttress, and extreme line)	4 ½ to 10 ¾	5000 (34.5)
	11 ¾ to 13 3/8	3000 (20.7)
	16 to 20	2000 (13.8)

4.6.3.12 The minimum inside diameter (ID) for lines downstream of the chokes shall be equal to or greater than the nominal connection size of the choke inlet and outlet.

4.6.3.13 Choke manifold valves shall be equal to or greater than the ID of the connected pressure lines..

4.6.3.14 For wells with a MASP of 5000 psi to 10,000 psi (20.7 MPa to 69.0 MPa), at a minimum, one choke should be remotely operable.

4.6.3.15 For wells with a MASP greater than 10,000 psi, at a minimum, two chokes shall be remotely operable.

4.6.3.16 Choke manifold configurations shall allow for rerouting of flow (in the event of eroded, plugged, or malfunctioning parts) through a different choke, without interrupting flow control.

4.6.3.17 ID of the bleed line (if installed) shall be at least equal to the ID of the choke line.

4.6.3.18 The choke control panel shall be capable of independently adjusting each remotely operated choke.

4.6.3.19 Power systems for remotely operated valves and chokes shall be sized to provide the pressure and volume required to operate the valve(s) at the RWP and flow conditions.

4.6.3.20 Any remotely operated valve or choke shall be equipped with an emergency backup power source or manual override.

4.6.4 Choke and Circulating Lines

4.6.4.1 Choke line installations should be assembled as straight as possible to minimize erosion and incorporate targeted tees and/or fluid cushions in accordance with API 16C.

4.6.4.2 At least one full-opening valve shall be installed between the BOP and choke line.

4.6.4.3 For wells capable of unassisted flow, at least two full-opening valves shall be installed between the BOP and the choke line. Full-opening choke line valves shall not be used to throttle or choke flow.

4.6.4.4 Choke lines, including the associated valves, should have an ID not less than 1.875 in.

4.6.4.5 Gauge and test port connections, including isolation valve(s), shall be rated for the pressure service and be in accordance with API 16C.

4.6.4.6 For MASP exceeding 5000 psi operations, at least one full-opening valve installed between the well control stack and the choke line shall be remotely operated.

4.6.5 Pump Lines

4.6.5.1 The pump line system provides a means of pumping into the tubing, drill pipe, or other tubular or wellbore, or both, to perform circulating or bull-heading operations. The pump line connects the fluid pumps to the tubular and kill line(s) on the BOP stack.

4.6.5.2 Pump lines shall be constructed of materials compatible with the fluid(s) pumped.

4.6.5.3 Pump line installations should be assembled to minimize erosion in accordance with API 16C.

4.6.5.4 Pump line components shall have a RWP greater than or equal to the MAOP of the operation.

4.6.5.5 For liquid pumping services, hoses used for the pump line shall be in accordance with API 7K.

4.6.5.6 For nitrogen pumping services, flexible lines (hoses) used for pump lines shall be in accordance with API 16C or API 7K.

4.6.5.7 An inline flow check device should be installed for each pump line.

4.6.5.8 Gauge and test port connections, including isolation valve(s), shall be rated for the pressure service in accordance with API 6A.

4.6.5.9 Over-pressure protection shall be provided to ensure that pump pressure cannot exceed the RWP of the pump lines.

4.7 BOP Accumulator Systems

4.7.1 Specifications for BOP Control Equipment

4.7.1.1 Modifications, alterations, or adjustments from the original design or intent of the BOP accumulator system shall be documented through the use of the equipment owner's MOC system.

4.7.1.2 BOP accumulator equipment shall meet the area classification requirements for the area in which it is installed.

4.7.2 Accumulator Fluid

4.7.2.1 Control fluid shall be selected and maintained to meet minimum BOP equipment manufacturers and fluid supplier's properties, and the equipment owner's requirements.

4.7.2.2 The control fluid shall be maintained to prevent freezing when necessary.

4.7.3 Accumulator Fluid Reservoir

4.7.3.1 Control fluid reservoirs shall be cleaned, flushed of contaminants, and have vents inspected before fluid is introduced in accordance with the equipment owner's maintenance system.

4.7.3.2 Sufficient accumulator reservoir fluid volume shall be verified daily

4.7.4 Accumulator Pump Systems

4.7.4.1 Pump System Descriptions

4.7.4.1.1 The following are descriptions of pump system for BOP control units for well servicing operations.

a) Dual power source and pump with automatic start and stop controls.

b) Dual power source and pump with

1) one (1) power source and/pump automatic start and stop controlled, and

2) one (1) power source and pump manually start and automatic stop controlled.

c) Single power source pump with one (1) power source and pump manually controlled.

NOTE Well Servicing units typically use diesel powered engines, gasoline powered engines, compressed air powered motors or electric powered motors.

4.7.4.1.2 Well Operator should perform a risk assessment to determine if minimum pump system requirements per Table 2 is sufficient or if they will set higher requirements. Dual power source and Pumps with Automatic Start/Stop Controls

4.7.4.1.3 A minimum of two pump systems shall be installed; a pump system may consist of one or more pumps.

4.7.4.1.4 Each pump system shall have an independent power source.

4.7.4.1.5 These pump systems shall be connected so that the loss of any one power source does not impair the operation of the pump systems, including pump suction lines (valve and Y strainer) and discharge lines (discharge check valves).

4.7.4.1.6 At least one pump system shall be available and operational, at all times.

4.7.4.1.7 The cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from precharge pressure to 97% to 100% of the system RWP within 15 minutes.

4.7.4.1.8 With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the main accumulator system from precharge pressure to the pressure pumps are set to shut off within 30 minutes.

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

4.7.4.1.10 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure (3000 psi [20.7 MPa] typical).

4.7.4.1.11 When applicable, per Table 2 the primary pump system shall automatically start before system pressure has decreased to 90 % (2700 psi) of the system RWP (3000 psi [20.7 MPa]) and automatically stop between 97 % to 100 % of the RWP (2940 psi – 3000 psi [20.3 MPa – 20.7 MPa]).

4.7.4.1.12 When applicable, per Table 2 the secondary pump system shall automatically start before system pressure has decreased to 85 % (2550 psi [17.6 MPa]) of the system RWP and automatically stop between 95 % to 100 % (2850 psi – 3000 psi [19.7 MPa – 20.7 MPa]) of the system RWP.

4.7.4.1.13 Air operated equipment shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply.

4.7.4.1.14 The air motor supply shall be capable of providing sufficient output to meet requirements of 4.9.4.2.5 and 4.9.4.2.6.

4.7.4.1.15 For normal use, the controllers should remain in the automatic position. Manual control is for use in emergency situations and for use by maintenance technicians.

4.7.4.1.16 Each pump system shall be protected from over pressurization by a minimum of two devices as follows:

a) one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed 5% above the RWP of the control system;

b) the second device, such as a certified relief valve, to limit the unit pressure to not more than 10% (3300 psi [22.8 MPa] typical) above system RWP.

4.7.4.1.17 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

4.7.4.1.18 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

4.7.4.2 Dual Power Source and /Pump with Automatic and Manual Start/Stop Controls

4.7.4.2.1 A minimum of two pump systems are required; a pump system may consist of one or more pumps.

4.7.4.2.2 Each pump system shall have an independent power source.

4.7.4.2.3 The pump systems shall be connected so that the loss of any one power source does not impair the operation of the pump systems, including pump suction lines (isolation valve and Y strainer) and discharge lines (discharge check valves).

4.7.4.2.4 At least one pump system shall be available and operational at all times.

4.7.4.2.5 The cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from precharge pressure to the system RWP within 15 minutes.

4.7.4.2.6 With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the main accumulator system from precharge pressure to the pressure pumps are set to shut off within 30 minutes.

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

4.7.4.2.8 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure (3000 psi [22.8 MPa] typical).

4.7.4.2.9 The primary pump system shall automatically start before system pressure has decreased to 90 % (2700 [18.6 MPa] psi) of the system RWP (3000 psi [20.7 MPa] and automatically stop between 97 % to 100 % of the RWP (2910 psi – 3000 psi [20.1 MPa – 20.7 MPa]).

4.7.4.2.10 The secondary pump system shall be manually started and automatically stop between 97 % to 100 % of the RWP (2910 psi – 3000 psi [20.1 MPa – 20.7 MPa]).

4.7.4.2.11 Air pumps shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply. The air supply shall be capable of providing sufficient output to meet requirements 4.9.4.3.5 and 4.9.4.3.6.

4.7.4.2.12 Each pump system shall be protected from over pressurization by a minimum of two devices:

a) one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed the RWP of the control system.

b) the second device, such as a certified relief valve, to limit the unit pressure to not more than 10% (3300 psi [22.8 MPa] typical) above system RWP.

4.7.4.2.13 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

4.7.4.2.14 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

4.7.4.3 Single Motor/Pump with Manual Controls

4.7.4.3.1 A pump system may consist of one or more pumps.

4.7.4.3.2 The pump system shall be available and operational at all times.

4.7.4.3.3 The output capacity of the pump systems shall be sufficient to charge the main accumulator system from pre-charge pressure to the system RWP within 15 minutes.

4.7.4.3.4 The same pump system may be used to provide control fluid to control both the BOP stack and the diverter system.

4.7.4.3.5 The pump system shall provide a discharge pressure at least equivalent to the control system working pressure (3000 psi typical).

4.7.4.3.6 The pump system shall be manually started and automatically stop between 97 % to 100 % of the RWP (2910 psi – 3000 psi [20.1 MPa – 20.7 MPa]).

4.7.4.3.7 Air pumps shall be capable of charging the accumulators to the system working pressure with 75 psi (0.52 MPa) minimum air pressure supply. The air supply shall be capable of providing sufficient output to meet requirements 4.7.4.3.3 and 4.7.4.3.6

4.7.4.3.8 The pump system shall be protected from over pressurization by a minimum of two devices as follows:

a) one device, such as a pressure switch, to limit the pump discharge pressure so that it will not exceed 5% above the RWP of the control system;

b) the second device, such as a certified relief valve, to limit the unit pressure to not more than 10 % (3300 psi [22.8 MPa] typical) above system RWP.

4.7.4.3.9 Devices used to prevent pump system over pressurization shall not have isolation valves or any other means that could defeat their intended purpose.

4.7.4.3.10 Rupture disc(s) or relief valve(s) that do not automatically reset shall not be installed.

4.7.5 Accumulator Location

The accumulator should be positioned a minimum of 50 ft (15 m) from the wellbore and any source of flammable gas or hydrocarbons.

4.7.6 Accumulator Pre-charge

4.7.6.1 A nonoxidizing inert gas, such as nitrogen or helium, shall be used for pre-charging accumulators.

4.7.6.2 Neither atmospheric air nor oxygen shall be used.

4.7.6.3 The gas used shall be in accordance with the accumulator OEM operating instructions.

4.7.6.4 The pre-charge pressure for each surface accumulator bottle shall be measured and adjusted in accordance with equipment owner's maintenance system.

4.7.6.5 The pre-charge pressure shall be adjusted in accordance with the API 16D method specified in the manufacturer's sizing documentation.

4.7.6.6 Documentation of the accumulator bottles pre-charge measurement and adjustment shall be retained and retrievable until the end of the well.

4.7.6.7 The pre-charge pressure shall not exceed the RWP of the accumulator.

4.7.7 Accumulators, Valves, and Pressure Gauge Requirements

4.7.7.1 No accumulator bottle shall be operated at a pressure greater than its RWP.

4.7.7.2 Bladder- and float-type accumulators shall be mounted in a vertical position.

4.7.7.3 Accumulator pre-charge pressure gauges shall meet the requirements of 14.13.1 (test pressure measurement devices).

4.7.8 Accumulator Interconnect Valves, Fittings, Lines, and Components

4.7.8.1 This section applies to rigid or flexible control lines between the control system and BOP stack(s) or between control system assemblies (e.g. HPUs [hydraulic power units], accumulator skids, etc.).

4.7.8.2 Accumulator system interconnect valves, fittings, and other components such as pressure switches, transducers, transmitters, etc., shall have an RWP at least equal to the RWP of their respective circuit.

4.7.8.3 Piping components and all threaded pipe connections installed on the BOP accumulator shall be in conformance to the design and tolerance specifications as specified in ASME B1.20.1.

4.7.8.4 Accumulator/closing unit connection to the BOP shall be made with fire resistant hoses, armor-covered fire resistant hoses, or steel lines within API 500 Class I, Division 2 areas, inclusive of adjustment factors.

4.7.8.5 Pipe, pipe fittings, and components shall conform to the requirements of ASME B31.3.

4.7.8.6 Welding shall be performed in accordance with ASME BPVC, Section IX.

4.7.8.7 Accumulator system interconnect piping, tubing, hoses, linkages, etc., shall be protected from damage during well servicing rig operations and day-to-day equipment movement.

4.7.8.8 Manually operated control valves shall be clearly marked to indicate which function(s) each operates and the position of the valves (e.g. open, closed, etc.).

4.7.9 Accumulator System Controls

4.7.9.1 The accumulator control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures.

4.7.9.2 The control station location shall provide visibility from the crew chief and easy accessibility for the crew.

4.7.9.3 Each function and the function position (e.g., open, closed) shall be clearly identified.

4.7.9.4 When installed, the following functions shall be protected to avoid unintentional operation:

a) shear rams close;

b) blind rams close.

4.7.9.5 The accumulator system shall be equipped and maintained with measurement devices to indicate the following (where the equipment/system is installed):

a) Accumulator system pressure;

b) Regulated manifold pressure;

c) Regulated annular pressure;

d) Air supply pressure;

e) Hydraulic fluid level

4.7.10 Remote Control Stations

The equipment user (production company) should do a risk analysis to determine the need for a remote-control station and required functions and specify such in their order to equipment suppliers.

EXAMPLES

— The ability to close all BOPs

— The ability to close and open all BOPs.

— Installation of gauges showing pressures (accumulator pressure, manifold pressure, annular pressure, air pressure).

— Installation of indicators showing position of control valves (open or closed).

4.8 Auxiliary Equipment

4.8.1 Kelly Valves/Full-open Safety Valves

A minimum of one Kelly valve shall be installed below the power swivel or top drive.

4.8.2 Drill Pipe or Tubing Safety Valve

4.8.2.1 A workfloor isolation valve that is not full opening is acceptable for use on PC-0 wells.

4.8.2.2 A drill pipe or tubing safety valve (FOSV) shall be readily available (i.e. stored in open position with wrench accessible) on the rig floor for all PC-1 through PC-4wells.

4.8.2.3 A second, tested and certified FOSV is recommended for PC-2 and required for PC-3 and PC-4 wells.

4.8.2.4 On PC-4 wells, a second, tested and certified FOSV shall be available on the well site

4.8.2.5 This valve(s) and crossover sub(s) shall be equipped with compatible threads to screw into any drill string member or tubing member in use.

4.8.2.6 The FOSV and crossovers shall have a drift ID that is greater than or equal to the tubulars in use.

4.8.2.7 A FOSV that is not rated for torque shall not be used for drilling or milling.

4.8.2.8 The outside diameter (OD) of the drill pipe safety valve or the tubing safety valve shall have suitable clearance for running into the hole.

4.8.3 Flare/Vent Lines

4.8.3.1 Flare/vent lines piping supports shall be in accordance with ASME B31.3.

4.8.3.2 Flare/vent lines should be as straight as possible to minimize back pressure.

4.8.3.3 Flare/vent lines shall have provisions for flaring/venting during varying wind directions.

4.8.3.4 For H_2S operations, the end of the flare line(s) shall be equipped with a remotely operated igniter to ignite the gas.

4.8.4 Power Swivel and Components

4.8.4.1 The power swivel shall be equipped with a Kelly valve located below the swivel stem/quill.

4.8.4.2 The power swivel and all components shall be rated for the wells MASP.

4.9 BOP System Pressure Sealing Components

4.9.1 Bolting

4.9.1.1 BOPE and circulating equipment bolting and nuts shall be part of the preventive maintenance program for the system.

4.9.1.2 The equipment owner's PM program shall specify inspection frequency; NDE (nondestructive examination); and acceptance criteria for bolts, studs, nuts, and clamps (if installed).

4.9.2 Bolted Connections

4.9.2.1 Wellbore pressure-containing connections shall be tightened and torqued in accordance with equipment manufacturer's recommendations.

4.9.2.2 Studs and nuts used in closure bolting shall be sized, rated, and installed in conformance with API 20E and 20F.

4.9.2.3 Bolting should not be used to force the end connections into alignment.

NOTE See ASME B16.5 for flanged joint alignment.

4.9.2.4 The OEMs procedure shall be followed when making up other end connections (OEC) manufactured in conformance with API 6A.

4.9.3 Ring-joint Gaskets

Metal ring gaskets shall not be re-used.

4.9.4 BOP Elastomer Components

4.9.4.1 The equipment user shall confirm with the OEM (original equipment manufacturer) that elastomers are compatible with the wellbore fluids.

NOTE The fluid environment of wellbore wetted surfaces will vary depending on well circumstances. It is important to note that some blends of wellbore fluids have detrimental effects on elastomeric seals.

4.9.4.2 Elastomeric components shall be inspected or replaced if they are exposed to an incompatible wellbore fluid.

4.9.4.3 All other elastomeric seals shall be designed to operate within the temperatures and pressures of the manufacturer's written specifications.

4.9.5 Accumulator Components

Accumulator components that are routinely disconnected and exposed shall be visually inspected for damage or degradation each time they are exposed.

4.9.6 Equipment Storage

4.9.6.1 Well control equipment should be stored in a manner that prevents degradation of the equipment's integrity.

4.9.6.2 Before returning to service, the components shall be inspected and tested in accordance with the equipment owner's or manufacturer's requirements.

4.9.6.3 Any elastomer seals found to be outside the manufacturer's recommended shelf-life expiration date shall be prohibited from installation in BOP systems.

4.10 BOP Preventers for H_2S Service

4.10.1 Applicability

Where there is a reasonable expectation of encountering H_2S (hydrogen sulfide) gas zones that could potentially result in the partial pressure of the H_2S exceeding 0.05 psia (0.00034 MPa) in the gas phase at the maximum anticipated pressure, the BOP and wellbore-wetted metallic equipment, excluding shear ram blades, shall be in accordance with NACE MR0175/ISO 15156.

NOTE Guidelines for conducting drilling operations in such an environment can be found in API 49,.

4.10.2 Equipment Verifications

4.10.2.1 Prior to installing a BOP stack on the location where H_2S is expected, the equipment user shall confirm that the well control equipment metallic components exposed to wellbore fluids and gasses are in accordance with NACE MR0175/ISO 15156 or an equivalent national or international standard. Elastomers shall be approved by the OEM for the anticipated H2S exposure.

4.10.2.2 If the BOP has been activated and shut in for an emergency event, elastomeric elements shall be replaced or inspected and tested in accordance with the equipment owner's maintenance system.

4.10.2.3 When H_2S is present, the well fluid shall be circulated (or other mitigation) prior to pressure testing BSRs (blind shear rams) to minimize the effect of H_2S on the higher-hardness metallic components.

NOTE Reference NACE MR0175/ISO 15156 for other operational mitigation procedures.

4.10.2.4 When the BOP stack has been subjected to fluids containing H_2S, the equipment manufacturer's recommendations shall be followed regarding the level of servicing and testing required during the maintenance period.

4.11 Pressure Measurement Devices

4.11.1 Test Pressure Measurement Devices

4.11.1.1 Test results shall be recorded using test pressure gauges and chart recorders or data acquisition systems.

4.11.1.2 Test pressure gauges and recording devices shall be calibrated annually according to the equipment manufacturer's procedures and requirements.

4.11.1.3 Analog test pressure measurements shall be made at not less than 25 % and not more than 75 % of the full pressure span.

4.11.1.4 Electronic pressure gauges, chart recorders, and data acquisition systems shall be used within the manufacturer's specified range.

4.11.1.5 Calibrations shall be traceable to a recognized national calibration standard.

4.11.2 Operational Pressure Measurement Devices

4.11.2.1 Analog and electronic pressure measurement devices shall be used within the manufacturer's specified range.

4.11.2.2 It is acceptable for gauges to be used during normal operations to read full scale, but these shall not serve as test gauges.

4.11.2.3 Operational pressure measurement devices shall be calibrated at least every three years.

4.11.2.4 Calibrations shall be traceable to a recognized national standard.

4.12 Inspection and Maintenance—BOPE Systems

4.12.1 Inspections

4.12.1.1 Inspection and maintenance of the well control equipment shall be performed in accordance with the equipment owner's maintenance system.

4.12.1.2 The equipment owner's maintenance system shall address the inspection (internal/external visual, dimensional, NDE, etc.) of well control equipment system components annually or more frequently for extreme service (high fluid velocity, abrasives, or corrosive fluids). Equipment inspection and testing should be traceable to either a visible marking system or a traceability method.

4.12.2 Periodic Maintenance and Inspection

4.12.2.1 BOPE stack shall be inspected at least every five years in accordance with the equipment owner's maintenance system. Individual components and subassemblies may be inspected on a staggered schedule.

4.12.2.2 The inspection results shall be verified against one of the following:

a) the manufacturer's acceptance criteria, or

b) the equipment owner's acceptance criteria if the equipment owner collects and analyzes condition-based data and performance data to justify their criteria.

4.12.2.3 The BOP stack five-year period shall begin using one of the following criteria:

a) The date the equipment owner accepts delivery of a new build well service rig with a BOP system;

b) The date that the inspected equipment is placed into service, when preservation and storage records are available;

c) The date of the last inspection for the component, if preservation and storage records are not available.

4.12.2.4 As an alternative to the schedule-based inspection program referenced in 5.4.2.3, the inspection frequency may vary from this five-year interval if the equipment owner collects and analyzes condition-based data (including performance data) to establish a different frequency.

4.12.2.5 Inspections shall be performed by a competent person(s).

4.12.2.6 Elastomeric components and the finishes of their seal surfaces should be inspected when equipment is disassembled.

4.12.2.7 Documentation of repairs and remanufacturing shall be maintained in accordance with 5.4.6.

4.12.3 Installation, Operation, and Maintenance Manuals

4.12.3.1 Procedures shall be maintained for the installation, operation, and maintenance of BOPE that account for differing rig, well, and environmental conditions.

4.12.3.2 The IOM (installation, operation, and maintenance) manuals shall be available for the BOPE s and circulating equipment installed on the rig.

4.12.4 Replacement Parts and Assemblies (non-OEM and OEM)

4.12.4.1 Replacement parts shall be in conformance with the relevant API standards and satisfy the design/operating requirements.

4.12.4.2 The manufacturer's markings for BOP stack wellbore wetted elastomeric components, including the durometer hardness, generic type of compound, date of manufacture, date of expiration, part number, and operating temperature range of the component shall be verified and documented.

4.12.5 Welding

4.12.5.1 Welding of wellbore pressure-containing, pressure-controlling, and/or load-bearing components shall be performed in accordance with ASME BPVC, Section IX.5.4.5.2 Welding of wellbore pressure-containing components shall be in accordance with the welding requirements of NACE MR0175/ISO 15156.

4.12.5.2 Verification of compliance shall be established through the implementation of a written WPS (weld procedure specification) and the supporting procedure qualification record (PQR) from the repair facility.

4.12.6 Planned Maintenance Program

4.12.6.1 A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, shall be implemented and documentation available for every BOPE.

4.12.6.2 Records for maintenance, repairs, and remanufacturing performed for the well control equipment shall be maintained on file at the rig site and preserved at an offsite location until the equipment is permanently removed from service.

4.12.6.3 Records of remanufactured parts and/or assemblies shall be readily available and preserved at an offsite location, including documentation that shows that the components meet applicable specifications.

4.12.7 Manufacturer's Product Alerts/Equipment Bulletins

The equipment manufacturer's product alerts or equipment bulletins for the well control equipment in use on the rig shall be maintained both at the rig site and at an offsite location.

4.12.8 Records and Documentation

4.12.8.1 Copies of applicable Energy Workforce and Technology Council (EWTC) best practices and/or API standards and specifications relative to the well control equipment shall be available.

4.12.8.2 Equipment documentation and drawings shall be amended or updated and available from the BOPE provider to identify the current equipment and assist with procuring correct replacement parts.

4.12.9 Posted Documentation – required for PC3 and PC-4

4.12.9.1 Drawings showing ram space-out and bore of the BOP stack, showing the pressure rating of the components shall be readily available and consistent with current BOP stack configuration..

4.12.9.2 For annular or ram preventers that require different closing pressures for different tubulars, closing pressure shall be obtained, posted, and the regulator pressure adjusted prior to placing the tubular in the annular or ram preventer.

4.12.10 Equipment Data Book and Certification

4.12.10.1 Equipment records (electronic or hard copy), manufacturing and/or remanufacturing documentation, certifications, and factory acceptance testing reports shall be retained as long as the equipment remains in service.

4.12.10.2 Copies of the manufacturer’s equipment data book shall be available for review.

4.12.10.3 Electronic and/or hard copies of documentation shall be retained at an offsite location as long as the equipment remains in service.

4.12.11 Maintenance History and Failure Reporting—

4.12.11.1 A maintenance and repair historical file shall be maintained by serial number by the BOPE equipment owner by serial number or unique identification number for each major piece of equipment.

4.12.11.2 The equipment owner shall report, in accordance with Annex D, well control equipment malfunctions or failures that

a) result in harm to personnel;

b) result in an unintended release of well bore fluids or control fluid to environment;

c) cause equipment damage;

d) are deemed by the equipment owner to be a failure that occurred prematurely in the maintenance lifecycle.

NOTE Equipment repairs that are deemed by the equipment owner to be normal wear and tear are not required to be reported.

4.12.12 Test Procedures and Test Reports

4.12.12.1 Testing after major modifications or welding of well control equipment shall be performed according to the manufacturer's written procedures.

4.12.12.2 Well bore procedures for installation, removal, operation, and testing of all well control equipment installed shall be available and followed.

4.12.12.3 Pressure and function test reports shall be recorded and retained including pre-installation and all subsequent tests for each well.

4.12.12.4 Pressure and function test reports shall be readily available on the rig site for the duration of the well program.

5 Testing—BOPE Systems

5.1.1 Purpose

The purpose for various field test programs on well servicing rig well control equipment is to verify the following:

a) that specific functions are operationally ready;

b) the pressure integrity of installed equipment;

c) the compatibility of the accumulator and BOP stack(s).

5.1.2 General

Well Head -specific procedures for testing of well control BOPE equipment shall be incorporated into acceptance tests; installation; and subsequent tests, drills, periodic operating tests, maintenance practices, and well servicing and/or completion operations.

5.1.3 Inspection Tests

Inspection tests of well BOPE equipment shall be performed in accordance with the equipment owner's maintenance system.

NOTE 1 Inspection test practices and procedure details can vary and are outside the scope of this document.

NOTE 2 Inspection tests can include, but are not limited to: visual, dimensional, audible, hardness, functional, pressure tests, and electrical testing.

5.1.4 Competency

Maintenance and testing shall be performed or supervised by a competent person(s).

NOTE Crew drills and containment rig practices are outside the scope of this document and are addressed in API 59.

5.1.5 Function Tests

5.1.5.1 Pressure tests or a draw down test shall qualify as function tests for that specific sealing element.

5.1.5.2 A pressure test shall be performed following the disconnection or repair and limited to the affected component(s).

5.1.5.3 Initial function testing shall be performed before operations commence in accordance with Table C.1.

5.1.5.4 Subsequent operational function testing shall be performed in accordance with Table C.2.

5.1.5.5 Scheduled function testing shall be performed in accordance with Table C.3.

5.1.5.6 Actuation times (and volumes, if applicable) shall be recorded (see example worksheets in Annex B).

5.1.6 Accumulator System Response Time

5.1.6.1 The measurement of the closing response time shall begin when the close function is activated at any control panel and shall end when the BOP or valve is closed.

5.1.6.2 The following response times shall be met:

a) close each ram BOP in 30 seconds or less;

b) close annular BOPs less than18 $^{3}/_{4}$ in. nominal size in 30 seconds or less;

c) close non-sealing shear rams in in 30 seconds or less.

5.1.7 Pressure Tests

5.1.7.1 BOP components that can be exposed to well pressure shall be tested first to a low pressure between 250 psig to 350 psig (1.72 MPa to 2.41 MPa), and then to a high pressure.

5.1.7.2 Initial pressures above 350 psig (2.41 MPa) shall be bled back to a pressure between 250 psig and 350 psig (1.72 MPa to 2.41 MPa) before starting the test. If the initial pressure exceeds 500 psig, pressure shall be bled back to zero and the test shall be reinitiated.

NOTE The higher pressure can initiate a seal that can continue to seal after the pressure is lowered, therefore misrepresenting a low-pressure condition.

5.1.7.3 The allowable test pressure tolerance above RWP shall not exceed 5 % of the RWP or 500 psi (3.45 MPa), whichever is less.

5.1.7.4 A pressure test of the pressure containing component shall be performed following the disconnection or repair, limited to the affected component.

5.1.7.5 All studs and nuts must be installed and preloaded or torqued to the applicable specifications, prior to the initial pressure test on connection that were disconnected.

5.1.7.6 Appropriate installation should be confirmed by the person in charge (PIC)

5.1.7.7 Initial pressure testing shall be performed before operations commence in accordance with Table C.4.

5.1.7.8 Subsequent operational pressure testing shall be performed in accordance with Table C.5.

NOTE With larger-size annular BOPs, some small movement can continue within the large rubber mass for prolonged periods after pressure is applied and can require a longer stabilization period.

5.1.8 Hydraulic Chamber Tests

5.1.8.1 A hydraulic chamber test shall be included in the equipment owner's maintenance system for operators on hydraulic connectors, BOPs, and outlet valves attached to the BOPs.

5.1.8.2 Chamber pressure tests shall be performed and charted as follows:

a) when equipment operator is replaced, repaired, or remanufactured.

b) in accordance with Table C.6.

5.1.9 Test Fluids

5.1.9.1 The initial installation pressure tests shall be conducted with solids free completion fluid, water or water with preservation, anti-freeze, and colorant additives.

5.1.9.2 During operations, the water or completion fluid in use is acceptable to perform subsequent tests of the BOP stack.

5.1.9.3 Accumulator and hydraulic chambers shall be tested using clean accumulator fluids with lubricity and corrosion additives for the intended service and operating temperatures.

5.1.10 Test Documentation

5.3.10.1 The results of BOP stack and circulating manifold pressure and function tests shall be documented.

NOTE Example worksheets are provided in Annex B.

5.1.10.2 BOP stack and circulating manifold pressure tests shall be documented with a pressure chart recorder or equivalent data acquisition system.

5.1.10.3 Test documentation should be signed by the test company representative, Rig Crew Chief (rig operator), , Rig Supervisor, and operator's representative.

NOTE This does not include maintenance testing such as hydraulic chamber tests.

5.1.10.4 Problems with the BOP system that result in an unsuccessful pressure test and actions to remedy the problem(s) shall be documented per the equipment owner's procedures.

5.1.11 General Testing Requirements

5.1.11.1 Personnel should be alerted when pressure test operations are to be conducted, when testing operations are underway, and when pressure testing has concluded.

5.1.11.2 Only designated personnel shall enter the test area to inspect for leaks when the equipment involved is under pressure.

5.1.11.3 Tightening, repair, or any other work shall be done only after verification that the pressure has been released.

5.1.11.4 Pressure shall be released only through pressure release lines.

5.1.11.5 When pressure testing, a procedural method shall be used to confirm pressure has been bled off.

5.1.11.6 Lines and connections that are used in the test procedures shall be secured.

5.1.11.7 Fittings, connections, and piping used in pressure-testing operations shall have an RWP equal to or greater than the maximum test pressure.

5.1.11.8 The drill pipe or tubing test joint should be capable of withstanding the tensile, collapse, and internal pressures that will be placed on it during the test operation.

5.1.11.9 A procedure shall be developed to identify test plug leaks.

5.1.12 BOPE Stack Equipment

5.1.12.1 The entire stack should be pressure tested as a unit on the well head after installation.

5.1.12.2 Shearing of drill pipe or tubing is not required with function and pressure testing.

5.1.12.3 Prior to testing each ram BOP, the secondary rod seals (emergency pack-off assemblies) shall be checked to ensure the packing has not been energized.

5.1.12.4 If the ram shaft seal leaks during the initial test, the seal shall be repaired rather than energizing the secondary packing.

5.1.12.5 Manual ram locks shall be lubricated and inspected annually, at a minimum.

5.1.12.6 Manual lock operators (e.g. handwheels) shall be available at the wellhead, ready and capable for operation.

5.1.13 Accumulator/Closing Unit Drawdown Test

NOTE 1 It is important to distinguish between the standards for in-the-field control system accumulator capacity established in this document and the sizing requirements established in API 16D.

NOTE 2 API 16D provides sizing requirements 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, and control valve interflow, as well as heat energy losses. Therefore, the establishment of the design accumulator capacity by the manufacturer provides a safety factor. This safety factor is a margin of additional fluid capacity that is not intended to be used for operating well control functions on the rig. For this reason, the control system design accumulator capacity formulas established in API 16D are different from the demonstrable capacity requirements listed below.

5.1.13.1 A drawdown test shall be conducted by actuating the specified BOP hydraulic chambers or any combination of available chambers that draw the same or larger volume as the specified BOP chamber.

5.1.13.2 Tests shall be completed at zero wellbore pressure.

5.1.13.3 Manifold and annular regulators shall be set at the manufacturer's recommended operating pressure for the BOP stack.

5.1.13.4 The drawdown test shall be performed as follows.

1) Position and properly secure a properly sized joint of drill pipe, tubing or a test mandrel in the BOP, as required.

2) Turn off the power supply to all accumulator charging pumps (air, electric, etc.).

3) Record the initial accumulator pressure.

4) Close the largest-volume annular BOP or any combination of operators with an equivalent or larger volume. Time each actuation. Response times shall be recorded.

5) Cycle a set of BOP rams with the smallest cumulative operating volume or any combination of operators with an equivalent or larger volume; time each actuation and record response times.

6) Record the final accumulator pressure; verify against acceptance criteria in Annex C.

NOTE The results of the test can be used to determine whether

— inadequate bottle pre-charge pressure exists;

— a failed bladder, piston, or float exists in the system;

— a temperature change has reduced effectiveness of the pre-charge gas;

— other leakage from within the system has occurred;

— improper alignment of valves has isolated some of the accumulator bottles.

5.1.13.5 A single BOP hydraulic chamber (pipe, blind, shear, or annular) may be functioned multiple times to simulate the multiple closure of same-sized hydraulic chamber, or to draw the fluid equivalent of a larger operator such as a shear ram or annular. Inversely, a larger operator can be used to simulate the draw of one or more smaller operators.

NOTE 1 Reducing accumulator working pressure to accumulator pre-charge pressure during this test can expose the accumulator bladders to damage. If the system is properly sized and operating as designed, this should not occur.

NOTE 2 When performing the accumulator/closing unit drawdown test, it will be beneficial to wait for the pressure to stabilized after the accumulator system was initially charged from pre-charge pressure to operating pressure. Waiting the allows the accumulator gas to cool to operating temperature.

NOTE 3 Because it takes time for the gas in the accumulator to warm up after performing all of the drawdown test functions, it is acceptable to wait 15 minutes after recording the pressure, if the pressure was less than the MOP (minimum operating pressure). If there is an increase in pressure, indications are that the gases are warming and there is still sufficient volume in the accumulators. If the MOP has not been reached after 15 minutes, an additional 15-minute wait may be necessary due to ambient temperatures negatively affecting the gas properties. After 30 minutes from the time the final pressure was recorded, if the MOP has not been reached, then it may be necessary to bleed down the system and verify pre-charge pressures and volume requirements for the system.

Annex A
(informative)

Accumulator Pre-charge Calculations

A.1 Accumulator sizing calculation Methods A, B, and C are defined in API 16D.

A.2 The accumulator pre-charge shall be applied utilizing the calculation method used in the accumulator system design sizing.

A.3 The optimal or user-determined pre-charge shall be confirmed to not exceed the accumulator system design sizing using the appropriate well-specific input requirements.

A.4 Conditions that affect the MOP shall be included in the MOP calculation (excluding main accumulator drawdown test calculation).

EXAMPLES MOPFLPS (minimum operator pressure for low-pressure seal), wellbore pressure effects, shearing/closing ratios, effective vent pressure, etc.

Annex B
(informative)

Example Worksheets and Calculations

The worksheets in Figure B.1, Figure B.2, and maximum expected wellbore pressure (MEWSP) calculations in Table B.1 are examples based on hypothetical BOP equipment system and are for illustration purposes only. Each user of this standard should develop their own approach. They are not to be considered exclusive or exhaustive in nature.

EXAMPLE - SURFACE BOP SYSTEMS FUNCTION TEST WORKSHEET

Rig Name: ____________________

Date: ____________________

By: ____________________

BOP Classification: ____________________

Station: ____________________

	Close		Open	
Function	**Time/Sec.**	**Vol./Gal.**	**Time/Sec.**	**Vol./Gal.**
Annular				
Blind/blind shear				
Lower pipe ram				
Middle pipe ram				
Upper pipe ram				
Choke valve				
Kill valve				

Does the accumulator system function the RAM and annular BOPs with the proper time limits?

Each RAM BOP within in 30 seconds or less.	**Yes**	**No**
Closing time shall not exceed 30 seconds for annular BOPs smaller than 18 3/4 in. nominal bore and 45 seconds for annular preventers of 18 3/4 in. nominal bore and larger.	**Yes**	**No**

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

Figure B.1—Example BOP Function Test Worksheet for Land and Surface Offshore

Rig Name : ______________________ **Performed By:** ______________________

Date: ______________________ **BOP Class Designation:** ______________________

Surface accumulator precharge pressure: __________ Accumulator Sizing MOP: __________

Initial accumulator pressure[3]: __________ Ambient Temperature: __________ °F (°C)

FUNCTIONS	**Functional Volume** **CLOSE**
Lower pipe ram	
Middle pipe ram	
Upper pipe ram	
Blind shear ram	
Annular	
MINIMUM DRAWDOWN DISCHARGE VOLUME REQUIREMENT:	

DRAWDOWN STEPS AND TEST RESULTS

Function[5]	**Gallons**	**Time[1,2]**	**Remaining Pressure**
TOTAL VOLUME DISCHARGED:		**FINAL PRESSURE[4]**	

ACCUMULATOR PRESSURE

Is the final pressure ≥ accumulator sizing MOP? **Yes** **No**

PUMP SYSTEM:

Pressure the pri pumps turn on: __________ Pressure the pri pumps turn off: __________

Pressure the sec pumps turn on: __________ Pressure the sec pumps turn off: __________

Charging Pumps: Record the time it takes to pump up the accumulator system with all pump systems. __________

The cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from end of drawdown to the system RWP within 15 minutes.

NOTES:

NOTE 1 Closing times should be recorded and compared against each subsequent test, as an indicator of potential problems in the system.

NOTE 2 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.

NOTE 3 When performing the accumulator drawdown test, it may be beneficial to wait a minimum of one hour from the time you initially charged the accumulator system from precharge pressure to operating pressure.

NOTE 4 Because it takes time for the gas in the accumulator to warm up after performing all of the drawdown test functions, you should wait 15 min after recording the initial pressure, if the final pressure was less than MOP. If there is an increase in pressure, indications are that the gasses are warming and there is still sufficient volume in the accumulators. If MOP has not been reached after 15 min you may have to wait an additional 15 min due to ambient temperatures negatively affecting the gas properties. After 30 minutes from the time the final pressure was recorded, if MOP has not been reached, then it may be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

Figure B.2—Example BOP Drawdown Test Worksheet for Land and Surface Offshore

Table B.1—Example Surface MEWSP Calculations Given Well and Equipment-specific Data

<table>
<tr><th>Actual or Calculated Shear Value
psig (MPa)</th><th>Maximum Allowable Working Pressure (MASP)
psig (MPa)</th><th>Shearing Ratio (SR)</th><th>Control System Operating Pressure
psig (MPa)</th></tr>
<tr><td>2174 (14.99)</td><td>5000 (34.47)</td><td>14.64</td><td>3000 (20.68)</td></tr>
<tr><td colspan="4">With Annular Open:
MEWSP = actual or calculated shear value
Example: 2174 psig (to shear pipe with the annular open)

With Annular Closed:
MEWSP = actual or calculated shear + (MASP/SR)
Example: 2174 + (5000/14.64) = 2516 psig (to shear pipe with MASP trapped under a closed annular)</td></tr>
<tr><td colspan="4">NOTE 1 These equations show relative shear pressures. Accumulator calculations should use absolute pressures.
NOTE 2 These calculations are presented as examples only and are not intended to restrict the use of other methods.</td></tr>
</table>

Annex C
(normative)

Testing

Table C.1 through Table C.6 shall be conducted at the prescribed frequency utilizing the listed test acceptance criteria.

Table C.1—Initial Function Testing, Surface BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria
Dedicated Accumulator Systems Test		
Dedicated shear accumulators[a]	Drawdown tested by operation of high-pressure shear function(s)	Verification of intended operation may be in the form of flowmeter volume counts (when available), pressure testing, or other applicable means Verification that components actuated per design Final accumulator pressure greater than the MOP to secure the well
Primary Control Systems Test		
Control stations[a,b,c]	Function test of all control stations and remote panels	Verification of intended operation
BOP stack operators and valves[a]	BOP functions tested (to include ram operators, annular operators, valves, high-pressure circuits) at maximum pressures expected for well control operations	Visual verification of no leaks Verification of intended operation may be in the form of visual inspection, flowmeter volume counts (when available), pressure testing, or other applicable means Response times to meet 5.3.6.2.0 Flowmeter volume counts (when available) to be within equipment owner's criteria
Main accumulator system[a] HPU pumps[a]	Drawdown test per 5.3.13 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes
BOP stack[a]	BOP to be drifted with a minimum diameter tool or drift as determined by the equipment owner and user's requirements	Pass completely through BOP stack after BOP initial pressure and function testing (16A acceptance criteria to drift within 30 minutes not applicable)
Full Opening Safety Valves		
Valves[a]	Function test	Verification of intended operation
Choke Manifold Test		
Adjustable chokes[a]	Function test	Verification of intended operation

[a] Not required for multiwell pad operations when moving to subsequent wells. Additional initial function testing is required for connections where the integrity of a pressure seal is broken.

[b] A function test from a remote panel satisfies the requirement for a local function test of the hydraulic control unit.

[c] Maintenance panels excluded.

Table C.2—Subsequent Operational Function Testing, Surface BOP Stacks

System/Component	Function Test Description	Test Acceptance Criteria	Frequency
Dedicated Accumulator Systems Test			
Dedicated emergency shear accumulators	Drawdown test With charging system isolated, discharge the volume of the greatest consuming emergency system mode	Accumulator pressure greater than the MOP to secure the well	Not to exceed 180 days
Control Systems Test			
BOP rams, annulars, choke and kill valves (excluding shear rams)	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2. Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 7 days
Casing shear rams, BSRs, and blind rams	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2. Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 21 days
High-pressure casing shear ram circuit and high-pressure BSRs close circuit	Function tested from one designated control station[a] Control stations to be alternated between tests	Verification of intended operation may be by recovery of system pressure, flowmeter readback, or other applicable means Response times to meet 5.3.6.2. Flowmeter volume counts (when available) to be within the equipment owner's criteria	Not to exceed 90 days
Main accumulator system HPU pumps	Drawdown tested per 5.3.13 Cumulative output capacity of pump systems to be timed, charging the main accumulator after drawdown test to system RWP	Verification that the final accumulator pressure is greater than the MOP specified in system accumulator sizing Verification that system RWP is achieved within 15 minutes	Not to exceed 180 days[b]
Full Opening Safety Valves			
Valves	Function test	Verification of intended operation	Daily
Choke Manifold Test			
Adjustable chokes	Function test	Verification of intended operation	Daily

[a] Maintenance panels excluded.

[b] Temperature variations can affect the usable volume in the accumulator system. An accumulator usable volume calculation or a drawdown test may be used to verify usable fluid when extreme temperature variations occur at the accumulator.

Table C.3—Scheduled Function Testing, Surface BOP Stacks

Primary Control Systems Test			
System/Component	**Function Test Description**	**Test Acceptance Criteria**	**Frequency[a]**
Control fluid reservoir (if applicable)	Control fluid reservoir mixing operation and level alarms	Verification that appropriate visual and/or audible alarm is received from each tank fluid level Verification of automatic mixing system functionality	Not to exceed 12 months
BOP stack hydraulic circuits	The integrity of the BOP stack hydraulic circuits to be verified with regulators set at maximum circuit pressure Test duration to be per equipment owner requirements	Visual verification of no leaks	Not to exceed 12 months
HPU pumps	HPU pump systems start and stop pressures	Verification that primary pump system automatically starts before system pressure has decreased to 90 % of the system RWP and automatically stops at system RWP ±2 % Verification that the secondary pump system automatically starts before system pressure has decreased to 85 % of the system RWP and automatically stops between 95 % and 100 % of the system RWP	Not to exceed 12 months

[a] Testing not to be conducted during operations.

Table C.4—Initial Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[a,c] psig (MPa)	Pressure Test—High Pressure[a,c]	
		Change Out of Component, Elastomer, or Ring Gasket	No Change Out of Component, Elastomer, or Ring Gasket
Annular preventer[b]	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% annular RWP, whichever is lower.
Fixed pipe, variable bore, blind, and BSR preventers[b,d]	250 to 350 (1.72 to 2.41)	RWP of ram preventer or wellhead system, whichever is lower	Initial pressure test
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	RWP of side outlet valve or wellhead system, whichever is lower	Initial pressure test
Choke manifold—upstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of ram preventers or wellhead system, whichever is lower	Initial pressure test
Choke manifold—downstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line(s), or MASP for the well program, whichever is lower	
Kelly, kelly valves, drill pipe safety valves, IBOPs	250 to 350 (1.72 to 2.41)	MASP for the well program	

[a] Pressure test evaluation periods shall be a minimum of five minutes with no visible leaks. The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] For multiple well pad operations, moving from one wellhead to another within the 21 days, pressure testing is required for pressure-containing and pressure-controlling connections when the integrity of a pressure seal is broken.

[d] For land operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented at commissioning and annually.

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

Table C.5—Subsequent Operational Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[a] psig (MPa)	Pressure Test—High Pressure[a]	Frequency
Annular preventer[b]	250–350 (1.72–2.41)	MASP or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above upper pipe ram preventers (wellbore side)	250–350 (1.72–2.41)	MASP or 70 % annular RWP, whichever is lower	Not to exceed 21 days
BOP side outlet valves above pipe ram preventers (non-wellbore side)	250–350 (1.72–2.41)	MASP	Not to exceed 21 days
Fixed and variable bore pipe ram preventers[b]	250–350 (1.72–2.41)	MASP	Not to exceed 21 days
Choke and kill line and BOP side outlet valves below pipe ram preventers (both sides)	250–350 (1.72–2.41)	MASP	Not to exceed 21 days
Choke manifold—upstream of chokes[c]	250–350 (1.72–2.41)	MASP	Not to exceed 21 days
Choke manifold—downstream of chokes[c]	250–350 (1.72–2.41)	RWP of valve(s), line(s), or MASP for the hole section, whichever is lower	Not to exceed 21 days
Kelly, kelly valves, drill pipe safety valves, IBOPs	250–350 (1.72–2.41)	MASP	Not to exceed 21 days
Blind and BSR preventers	250–350 (1.72–2.41)	MASP test pressure	Not to exceed 21 days

[a] Pressure test evaluation periods shall be a minimum of five minutes with no visible leaks. The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the smallest OD pipe expected to be used in the next 21 days.

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

Table C.6—Operating Chamber Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure psig (MPa)	Pressure Test—High Pressure[a]	Frequency
Annular preventer open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
BOP choke and kill valve open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Ram preventer open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months
Casing shear ram open and closing operating chambers	Not required	RWP as specified by equipment manufacturer	Every 12 months

[a] Pressure test evaluation periods shall be a minimum of five minutes with no visible leaks. The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] If the BOP is in operation, the test is to be conducted during the BOP next planned maintenance.

Bibliography

[1] API Standard 16AR, *Standard for Repair and Remanufacture of Drill-through Equipment*

[2] API Specification 20E, *Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries*

[3] API Specification 20F, *Corrosion Resistant Bolting for Use in the Petroleum and Natural Gas Industries*

[4] API Recommended Practice 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2

[5] API Recommended Practice 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2