Blowout Prevention Equipment Systems for Drilling Wells

API STANDARD 53
FOURTH EDITION, NOVEMBER 2012
ADDENDUM 1, JULY 2016

AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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Introduction

This standard represents a composite of the practices employed by various operating and drilling companies in drilling operations.This standard is under the jurisdiction of the API Drilling and Production Operations Subcommittee.

The objective of this standard and the recommendations within is to assist the oil and gas industry in promoting personnel safety, public safety, integrity of the drilling equipment, and preservation of the environment for land and marine drilling operations. In the context of blowout prevention systems, this objective is best attained through a combination of equipment reliability and management of risk. This standard is published to facilitate the broad availability of proven, sound engineering and operating practices that meet the stated objective through practices that improve reliability and reduce risk to acceptable levels. This standard does not present all of the operating practices that can be employed to successfully install and operate blowout preventer systems in drilling, completions, and well testing operations. Practices set forth herein are considered acceptable for accomplishing the job as described; however, equivalent alternative installations and practices can be used to accomplish the same objectives. Individuals and organizations using this standard are cautioned that operations must comply with requirements of federal, state, or local regulations. These requirements should be reviewed to determine whether violations can occur.

The First Edition of API 53, published in February 1976, superseded API Bulletin D13, *Installation and Use of Blowout Preventer Stacks and Accessory Equipment*, February 1966. The Second Edition of API 53 was issued in May 1984 and the Third Edition of API 53 was issued in March 1997. This edition supersedes all previous editions of this standard.

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

Blowout Prevention Equipment Systems for Drilling Wells

1 Scope

1.1 Purpose

1.1.1 The purpose of this standard is to provide requirements on the installation and testing of blowout prevention equipment systems on land and marine drilling rigs (barge, platform, bottom-supported, and floating).

1.1.2 Blowout preventer equipment systems are comprised of a combination of various components. The following components are required for operation under varying rig and well conditions:

a) blowout preventers (BOPs);

b) choke and kill lines;

c) choke manifolds;

d) control systems;

e) auxiliary equipment.

1.1.3 The primary functions of these systems are to confine well fluids to the wellbore, provide means to add fluid to the wellbore, and allow controlled volumes to be removed from the wellbore.

1.1.4 Diverters, shut-in devices, and rotating head systems (rotating control devices) are not addressed in this standard (see API 64 and API 16RCD, respectively); their primary purpose is to safely divert or direct flow rather than to confine fluids to the wellbore.

1.2 Well Control

Procedures and techniques for well control are not included in this standard since they are beyond the scope of equipment systems contained herein.

1.3 BOP Installations

This standard contains a section pertaining to surface BOP installations followed by a section on subsea BOP installations.

1.4 Equipment Arrangements

Recommended equipment arrangements as set forth in this publication are adequate to meet specified well conditions. It is recognized that other arrangements can be equally effective in addressing well requirements and achieving safety and operational efficiency.

1.5 Extreme High- and Low-temperature Operations

High- and low-temperature values are identified in API 16A for metallic and nonmetallic parts.

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 applies (including any addenda/errata).

API Specification 5L, *Line Pipe*

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

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

API Specification 16C, *Choke and Kill Equipment*

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

API Specification 17D, *Subsea Wellhead and Christmas Tree Equipment*

API Specification 17H, *Recommended Practice for Remotely Operated Vehicles (ROV) Interfaces on Subsea Production Systems*

API Recommended Practice 75, *Development of a Safety and Environmental Management Program for Offshore Operations and Facilities*

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*

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*

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

ASME B31.3, *Process Piping*

ASME *Boiler and Pressure Vessel Code (BPVC)* [1], *Section VIII*: *Pressure Vessels*

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

NACE MR 0175/ISO 15156 [2] [3], (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

3.1 Terms and Definitions

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

3.1.1
accumulator
A pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

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1 ASME International, 3 Park Avenue, New York, New York 10016, www.asme.org.

2 NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

3 International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva, Switzerland, www.iso.org.

3.1.2
adapter spool
A spool used to connect drill-through equipment with different end connections, nominal size designation, and/or pressure ratings to each other.

3.1.3
annular blowout preventer
A blowout preventer that uses a shaped elastomeric sealing element to seal the space between the tubular and the wellbore or an open hole.

3.1.4
articulated line
An articulated line is a choke or kill line assembled as a unit, with rigid pipe, swivel joints, and end connections, designed to accommodate specified relative movement between end terminations.

3.1.5
bell nipple
mud riser
flow nipple
A piece of pipe, with inside diameter equal to or greater than the blowout preventer bore, connected to the top of the blowout preventer or marine riser with a side outlet to direct the drilling fluid returns to the shale shaker pit.

NOTE This pipe usually has a second side outlet for the fill-up line connection.

3.1.6
blind ram
A closing and sealing component in a ram blowout preventer that seals the open wellbore.

3.1.7
blind shear ram
BSR
A closing and sealing component in a ram blowout preventer that first shears certain tubulars in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore.

3.1.8
blowout
An uncontrolled flow of well fluids and/or formation fluids from the wellbore to surface or into lower pressured subsurface zones (underground blowout).

3.1.9
blowout preventer
BOP
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, completion, and testing operations.

NOTE BOPs are not: gate valves, workover/ intervention control packages, subsea shut-in devices, well control components (per API 16ST), intervention control packages, diverters, rotating heads, rotating circulating devices, capping stacks, snubbing or stripping packages, or nonsealing rams.

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

3.1.11
blowout preventer stack
The complete assembly of well control equipment, including preventers, spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies.

3.1.12
buffer tank
A targeted, horizontal, cylindrical tank that changes the direction of fluid flow downstream of the choke and serves to direct flow to the flare line or gas buster.

3.1.13
casing shear ram
CSR
A closing component in a ram blowout preventer that is capable of shearing or cutting certain tubulars.

NOTE Casing shear rams are not required to seal.

3.1.14
choke
A device with either a fixed or variable aperture used to control the rate of flow of liquids and/or gas.

3.1.15
choke/kill line valve
The valve(s) connected to and a part of the BOP stack that controls the flow to the choke and kill manifold.

3.1.16
choke/kill line
A high-pressure line that allows fluids to be pumped into or removed from the well with the BOPs closed.

3.1.17
choke/kill manifold
An assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.

3.1.18
clamp connection
A pressure-sealing device used to join two items without using conventional bolted flange joints.

NOTE The two items to be sealed are prepared with clamp hubs. These hubs are held together by a clamp containing four bolts.

3.1.19
closing ratio
The area of the operating piston exposed to the close operating pressure, divided by the cross sectional area of the piston shaft exposed to wellbore pressure.

3.1.20
competent person
A person with characteristics or abilities gained through training, experience, or both, as measured against the manufacturer's or equipment owner's established requirements.

3.1.21
conductor pipe
A relatively short string of large diameter pipe that is set to keep the top of the hole open and provide a means of returning the up flowing drilling fluid from the wellbore to the surface drilling fluid system until the first casing string is set in the well.

3.1.22
control manifold
The system of valves and piping to control the flow of hydraulic fluid to operate the various components of the BOP stack.

3.1.23
control pod
An assembly of valves and regulators (either hydraulically or electrically operated) that when activated will direct hydraulic fluid through special apertures to operate the BOP equipment.

3.1.24
control station/panel, remote
A panel containing a series of controls that will operate the BOP functions from a location that is remote from the hydraulic control manifold or central processor in the case of a MUX or multiplex control system.

NOTE The control station for a discrete hydraulic system is at the HPU.

3.1.25
drill floor substructure
The foundation structure(s) on which the derrick, rotary table, drawworks, and other drilling equipment are supported.

3.1.26
drill pipe safety valve
An essentially full-opening valve located on the rig floor with threads to match the drill pipe connections or other tubulars in use.

NOTE This valve is used to close off the drill pipe to prevent flow and may be crossed over to fit other connections and sizes of tubulars being installed in the well.

3.1.27
drilling spool
A connecting component either flanged or hubbed, fitted between BOP equipment, with outlets.

3.1.28
drill string float
A check valve in the drill string that will allow fluid to be pumped into the well but will prevent wellbore fluids from entering the drill pipe.

3.1.29
drive pipe
A relatively short string of large diameter pipe driven or forced into the ground to function as conductor pipe.

3.1.30
equipment owner
The purchaser or renter of the equipment to be installed on the wellhead.

NOTE In most cases this is the drilling contractor.

3.1.31
equipment user
The 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.

3.1.32
fill-up line
A line usually connected into the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the hole, at atmospheric pressure.

3.1.33
flex/ball joint
Device(s) installed between the bottom of the diverter and above the LMRP, to permit relative angular movement of the riser, to reduce stresses due to vessel motion and environmental forces.

3.1.34
flow line
The piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.35
full-bore valve
A valve with unobstructed flow area dimensionally equal to or greater than the nominal connection size.

3.1.36
function test
The operation of a piece of equipment or a system to verify its intended operation.

3.1.37
gate valve
A valve that employs a sliding gate to open or close the flow passage.

NOTE The valve may or may not be full opening.

3.1.38
hang-off
An action whereby the weight of that portion of the drill string below a ram BOP is supported by a tool joint resting on the closed pipe ram or through the use of a special hang-off tool that lands in the wellhead.

3.1.39
high-pressure, high-temperature well
Wells with a potential pressure greater than 15,000 psi (103.42 MPa) at the wellhead or with a potential flowing temperature of greater than 350 °F (177 °C) at the wellhead.

3.1.40
hydraulic chamber test
The application of a pressure test to any hydraulic operating chamber.

3.1.41
hydrogen sulfide
H_2S
A highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon bearing formations.

3.1.42
hydrogen sulfide equipment service
Equipment designed to resist the effects caused by exposure to hydrogen sulfide (H_2S).

3.1.43
hydrostatic head
The pressure that is exerted at any point in the wellbore, due to the weight of the column of fluid above that point.

3.1.44
inside blowout preventer
IBOP
A device that can be installed in the drill string that acts as a check valve allowing drilling fluid to be circulated down the string but prevents back flow.

3.1.45
interlock sequencing
An arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another function.

3.1.46
kelly cock
kelly valve
Valves installed immediately above and below the kelly that can be closed to confine pressures inside the drill string.

3.1.47
kick
Influx of formation liquids or gas into the wellbore.

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

3.1.48
lost returns
Loss of drilling fluid into the formation resulting in a decrease in pit volume.

3.1.49
maximum anticipated surface pressure
MASP
A design load that represents the maximum pressure that may occur in the well during the construction of the well.

NOTE As with land and shelf wells, the MASP is a surface pressure.

3.1.50
maximum anticipated wellhead pressure
MAWHP
The highest pressure predicted to be encountered at the wellhead in a subsea well.

NOTE The MAWHP may be calculated for each hole section during well construction.

3.1.51
maximum expected wellbore shear pressure
MEWSP
The expected operating pressure for a given hole section, a specific shear pressure requirement, specific operating piston design, and material specification, to shear drill pipe or tubing at the MASP (surface), MAWHP (subsea), or other pressure limiting value.

3.1.52
original equipment manufacturer
OEM
The design owner or manufacturer 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, the assembly, part, or component is not considered an OEM product. The party that performs these alterations is then designated as the OEM.

3.1.53
pipe ram
A closing and sealing component in a ram blowout preventer that seals around the outside diameter of a tubular in the wellbore.

3.1.54
pit volume indicator
A device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.55
pit volume totalizer
A device that combines all of the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.56
pressure-containing equipment
Equipment [(part(s) or member(s)] exposed to wellbore fluids whose failure to function as intended can result in a release of wellbore fluid to the environment.

3.1.57
pressure-controlling
The control of the movement of pressurized fluids.

3.1.58
pressure regulator
A control system component that permits attenuation of control system supply pressure to a satisfactory pressure level to operate components downstream.

3.1.59
pressure test
The periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system.

3.1.60
rated working pressure
RWP
The maximum internal pressure that equipment is designed to contain or control.

NOTE 1 Indicative of wellbore wetted rated components or systems.

NOTE 2 Rated working pressure should not be confused with test pressure.

3.1.61
repair
Activity involving disassembly, reassembly, or replacement of components and testing of equipment.

NOTE Repair does not include machining, welding, heat treating, or other manufacturing operations.

3.1.62
remanufacture
Activity involving disassembly, reassembly, and testing of equipment where machining, welding, heat treating, or other manufacturing operations are employed.

3.1.63
shearing ratio
SR
The higher value of the closing ratios provided by the manufacturer.

NOTE The shearing ratio is dependent on piston size and/or booster addition.

3.1.64
shuttle valve
A checking type valve that shifts between two or more inlets allowing the movement of control fluid to and from multiple sources.

3.1.65
spacer spool
A spool used to provide separation between two components with equal sized end connections.

3.1.66
stable
stabilized
A state in which the pressure change rate has decreased to within acceptable limits before beginning the hold period during a pressure test.

NOTE Pressure changes can be caused by such things as variations in temperature, setting of elastomer seals, or compression of air or fluids, etc.

3.1.67
stored hydraulic fluid
The fluid volume recoverable from the accumulator system between the maximum designed accumulator operating pressure and the precharge pressure.

3.1.68
subsea BOP
Blowout preventer stack designed for use on subsea wellhead and wellhead assemblies, complete with redundant controls.

3.1.69
subsea well hop
When a BOP is unlatched from one wellhead and latched to another wellhead without retrieval to the surface.

3.1.70
surface base precharge pressure
Precharge value that is appropriate for surface testing.

NOTE 1 This value should be available within the manufacturer's operations and maintenance manual.

NOTE 2 This value is used in Methods A and B accumulator calculations as defined in API 16D and referenced in Annex C.

3.1.71
surface base pressure
Minimum operating pressure of the hydraulic circuit for supplying power to the function(s).

NOTE 1 This is usually a regulated 1500 psig.

NOTE 2 Exceptions are to special functions that have a specific pressure requirement, such as shear rams used to cut a specific drill pipe or tubing.

NOTE 3 This value is used in Method C accumulator calculations as defined in API 16D and referenced in Annex C.

3.1.72
umbilical
A control hose bundle or electrical cable that runs from the reel on the surface to the subsea control pod on the LMRP.

3.1.73
visual position indicator
A visible means of determining the position of a valve, ram, connector, or annular activation to indicate the full open or close position.

3.1.74
well control equipment
Systems and subsystems (components, parts, or assemblies) that are used to control pressure within the wellbore.

3.2 Abbreviations

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

ANSI American National Standards Institute

BOP blowout preventer

BSR blind shear ram

CSR casing shear ram

EDS	emergency disconnect sequence
HPU	hydraulic power unit
H_2S	hydrogen sulfide
IBOP	inside blowout preventer
ID	inside diameter
IOM	installation, operation, and maintenance
LMRP	lower marine riser package
MBR	minimum bend radius
MGS	mud gas separator
MPa	megapascal
MASP	maximum anticipated surface pressure
MAWHP	maximum anticipated wellhead pressure (for subsea wells)
MEWSP	maximum expected wellbore shear pressure
MOC	management of change
MUX	multiplex system
MWP	maximum working pressure
NDE	nondestructive examination (ultrasonic, radiographic, dye penetrant, acoustic emission, etc.)
NIST	National Institute of Standards and Technology (U.S.)
OEC	other end connections
OEM	original equipment manufacturer
OD	outside diameter
P&ID	piping and instrumentation diagram
PM	preventive maintenance
PQR	procedure qualification record
RWP	rated working pressure
SOP	standard operating procedure(s)
SR	shearing ratio
SSC	sulfide stress cracking
VBR	variable-bore ram
WPS	weld procedure specification

4 BOP Pressure Sealing Components

4.1 General

This section addresses the pressure-containing elements of the BOP system. As defined by API 16A, these are components exposed to wellbore fluids whose failure to function as intended can result in a release of retained fluid to the environment. In the BOP stack these pressure-containing elements include flanges and hubs, the bolting and clamps that join them and ring-joint gaskets. They also include, in subsea BOP systems, the subsea wellhead connector, the lower marine riser package (LMRP) connector, and finally the choke and kill lines on the LMRP and on the marine riser system.

4.2 Flanges and Hubs

4.2.1 When flanged or studded connections are used in BOP systems, they shall be in accordance with API 6A (Type 6B or Type 6BX) or API 17D (Type API 17SS or API 17SV) designs.

4.2.2 When clamp type hub connections are used in BOP systems they shall be in accordance with API 16A, Type 16B or 16BX designs.

4.2.3 If non-API clamp hub connections are used, they shall meet or exceed the requirements for other end connections (OEC) as defined in API 6A.

4.2.4 For flanges and clamp hubs, API 6A, API 16A, and API 17D give sizes, service conditions, dimensions, and other design requirements.

4.2.5 Non-API ring joint gaskets may be used in flanges or hubs. In such cases the resulting non-API connection is considered an OEC (see 4.4).

4.2.6 Manufacturers shall provide users with complete information on service conditions, dimensions, and other specifications for flanges and hubs used in BOP systems.

4.3 Bolting, Flanges, and Clamps

4.3.1 Bolting, flanges, studs, nuts, and pressure-containing joints in BOP systems, shall be in accordance with API 6A, API 16A, and API 17D, as applicable. This requirement also extends to bolting used for clamp connections.

4.3.2 Bolting used in the pressure end-load path of proprietary design of subsea wellhead connectors shall be in accordance with the manufacturer's written specification.

4.3.3 A recognized quality assurance program shall be used in the procurement and documentation of bolting for BOP systems.

4.3.4 All BOP system bolting and nuts shall be part of the preventive maintenance (PM) program for the system.

4.3.5 The BOP PM program shall include visual inspection of bolts, nuts, and clamps to confirm tightness and surface condition.

4.3.6 The equipment owner's PM program shall identify frequency, nondestructive examination (NDE), and acceptance criteria for bolts, nuts, and clamps.

4.3.7 Clamps for pressure-containing hubs, in BOP systems, shall be maintained, inspected and installed in accordance with API 6A.

4.3.8 Clamps for non-API hubs shall meet the requirements for OEC as specified in API 6A.

4.4 Ring-joint Gaskets

4.4.1 Detailed specifications for ring-joint gaskets, including gasket materials, coatings, plating, and identification marking, are included in API 6A, API 16A, and API 17D.

4.4.2 For OEC, including proprietary hubs and modified API flanges, other ring-joint gaskets may be specified; examples include AX-, CX-, and VX-type gaskets. These are acceptable in such applications, consistent with the OEC requirements given in API 16A and API 6A.

4.4.3 Only pressure-energized ring gaskets shall be used on well control equipment.

4.4.4 Metal ring gaskets shall not be reused unless specifically designed for that purpose.

NOTE Metal ring gaskets may be reused for stump testing.

4.5 External Pressure Effects on Ring-joint Gaskets

4.5.1 For subsea BOP system applications, external pressure capacity may be a performance concern in the design of sealing for pressure-containing joints. This is especially so as water depth and thus ambient hydrostatic pressure increase. It is of special concern because of the potential for unanticipated loss of fluid gradient inside the equipment due to gas-in-solution and to lost circulation events.

4.5.2 Just as with the flange and hub connections themselves, manufacturers shall provide equipment owners with complete information on external pressure capacity and performance of ring joint gaskets used in BOP systems. This includes API RX, BX, SRX, and SBX gaskets used in API flanges and hubs, as well as proprietary gaskets (AX, CX, etc.) used in OEC.

4.5.3 Subsea BOP system owners shall survey and evaluate all pressure-containing joints in the BOP system to ensure adequate performance under the effects of external pressure for the specific subsea applications.

4.5.4 Manufacturers should clearly state the external pressure rating of each joint/seal including valve stems, annular BOP seals, or ram type piston locking mechanism at any point that forms a barrier from internal to external pressure.

4.6 Subsea Wellhead Connector and Wellhead Gasket

4.6.1 In subsea BOP systems, the connection of the BOP to the wellhead is made by a proprietary-design wellhead connection and metal-to-metal sealing gasket.

4.6.2 Resilient ring gaskets may be used as a temporary means of obtaining a seal if approved by a management of change (MOC) and risk assessment for the applicable operations.

4.6.3 Subsea wellhead connectors and wellhead gaskets are not in accordance with API design specifications and thus are not classified as OEC. Manufacturers should provide the equipment owner with complete information on service conditions, load capacities, and basic (nonproprietary) dimensions of the wellhead connector.

4.6.4 The external pressure capacity and performance of all gasket seals shall be provided to the equipment owner, along with information on available contingency seals.

4.6.5 The subsea wellhead connector may also incorporate a hydrate seal. This seal, typically an elastomeric seal against the outside of the wellhead, acts to prevent external hydrate buildup resulting from gas migrating from shallow well annuli into the connector-to-wellhead interface.

4.6.6 For subsea BOPs operating in hydrate-prone areas, the wellhead connector shall incorporate a means to remotely inject methanol external to the primary sealing system and clamping arrangement. This port may also be used as an external low pressure test to confirm the effectiveness of the hydrate seal if one is installed.

4.7 Subsea Lower Marine Riser Package Connector and Gasket

4.7.1 If the subsea BOP system includes BOPs in the LMRP (e.g. annular BOPs) then the LMRP riser connector shall be considered as a pressure-containing joint of the system.

4.7.2 In such cases, the provisions in 4.6 for the wellhead connector and gasket shall apply to the riser connector and gasket.

4.8 Subsea Choke and Kill Lines

4.8.1 Subsea BOP systems include choke and kill lines built into the BOP stack and LMRP and integrated with the marine riser system.

4.8.2 These two fluid lines provide redundancy, as well as multiple access points to the BOP stack and allow for well control operations as follows:

— circulating down one line and up the other line;

— circulating down the drill pipe and up either line, or both lines;

— pump/bullhead down one or both lines;

— allow well pressure monitoring.

4.8.3 On the BOP stack and the LMRP, the choke and kill lines are provided with multiple gate valves for closure and pressure control, with flange or hub connections per API 6A, API 16A, and API 17D, as applicable.

4.8.4 The remote connection of the choke and kill lines from the BOP stack to the LMRP is made by proprietary connection, either pin and box (with elastomeric radial seal) or hub and connector (with metal-to-metal gasket). The connection of the choke and kill lines integrated in the marine riser is made, joint-to-joint, by proprietary box-and-pin, stab-in couplings (with elastomeric radial seal). All of these choke and kill connections shall be considered pressure-containing connections. Their metal gasket seals, whether API, OEC, or proprietary, shall conform to the same conditions as described in 4.4, 4.5, and 4.6.

4.8.5 The equipment user shall consider measures to ensure performance in deep water is not impacted by external to internal pressure differential acting on the system.

4.9 Wetted Elastomeric Sealing Components

4.9.1 Elastomeric wellbore (wetted) sealing components are any seal that comes in contact with wellbore fluids, (e.g. annular packers, ram block seals, operator rod or stem seals, valve seat, etc.).

4.9.2 In subsea BOP systems the environmental seals of each marine riser coupling may be primarily elastomeric. The primary telescopic joint seal assembly consists of a hydraulic or pneumatic pressure-energized elastomeric packing element(s).

4.9.3 All BOP system elastomeric seal elements shall be addressed in the equipment owner's PM program for the system.

4.9.4 The manufacturers shall provide the equipment owner with information to include in the PM program identifying frequency of inspection or renewal, and acceptance criteria for all elastomeric seals.

4.9.5 Riser joints shall be inspected for damage or degradation of all elastomeric seals and seal areas on riser connectors and on choke and kill connections prior to and/or during running the marine riser.

4.10 Fluid Service Conditions for Wetted Sealing Components

4.10.1 The fluid environment of wellbore wetted surfaces will vary, depending on well circumstances. It is important to note that some blends of drilling and completion fluids have detrimental effects on elastomeric seals. The original equipment manufacturer (OEM) shall be consulted regarding compatibility with drilling and completion fluids.

4.10.2 Manufacturer/vendor shall provide material compatibility testing results to the equipment owner, to ensure correct fluid service rating and performance. This is critical if the equipment owner plans well testing back to the rig.

4.10.3 Consideration shall be given to elastomeric seal compatibility with high-pressure, high-temperature conditions.

4.10.4 Considerations shall also be given to elastomeric seal compatibility with extreme low temperature and pressure variations.

4.10.5 Elastomeric components shall be replaced, as soon as practical, after exposure to hydrogen sulfide (H_2S) and/or CO_2, under pressure, in accordance with the original equipment manufacturer (OEM) or equipment owner's requirements.

4.11 Nonwetted Elastomeric Components

4.11.1 The nonwetted, nonwellbore elastomeric sealing elements in the BOP system are used in control system components, hydraulic actuators, and hydrate seals, etc. These seals are neither wellbore pressure-containing nor pressure controlling.

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

4.11.3 In the hydraulic junction boxes there are stab subs or multiple check valve-type quick disconnect couplings, where again the primary seals are O-rings.

4.11.4 In addition to the control system, hydraulic actuators utilize elastomeric seals. These actuators include BOP actuating systems and gate valve actuators.

4.11.5 Nonwetted elastomeric seals that are routinely disconnected and exposed (e.g. control system connections) shall be visually inspected for damage or degradation each time they are exposed on deck.

4.12 Equipment Marking and Storage

4.12.1 Marking and storage of sealing components of BOP systems shall be in accordance with API 6A, API 16A, or API 17D, as applicable, including identification marking of ring gaskets, bolts, nuts, clamps, and elastomeric seals.

4.12.2 Elastomeric seals shall be marked or tagged using the equipment manufacturer-defined coding system.

4.12.3 At a minimum the markings shall include information regarding the durometer hardness, generic type of compound, dates of manufacture and of expiration (month/year), lot/serial number, manufacturer's part number, and the operating temperature range of the component.

4.12.4 Any elastomer seals found to be outside the manufacturer's recommended expiration date shall be discarded and prohibited from use in BOP equipment systems.

4.12.5 Specialized components, including proprietary design BOP seals and packing units, shall be stored in accordance with the OEM’s recommendations.

5 Blowout Preventers for Hydrogen Sulfide Service

5.1 Applicability

5.1.1 Where there is reasonable expectation of encountering H_2S 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 well control critical equipment to be installed shall be in accordance with NACE MR0175/ISO 15156.

5.1.2 Recommended safety guidelines for conducting drilling operations in such an environment can be found in API 49.

5.2 Equipment Modifications

5.2.1 Equipment modifications should be considered since many metallic materials in a H_2S environment (sour service) are subject to a form of hydrogen embrittlement known as sulfide stress cracking (SSC). This type of spontaneous brittle failure is dependent on the metallurgical properties of the material, the total stress or load (either internal or applied), and the corrosive environment.

5.2.2 A list of acceptable materials is given in NACE MR0175/ISO 15156.

5.2.3 All metallic materials that can be exposed to H_2S under probable operating conditions shall be resistant to SSC.

5.2.4 The maximum acceptable hardness for all preventer and valve bodies and spools shall be in accordance with NACE MR0175/ISO 15156.

5.2.5 Ring-joint gaskets shall meet the requirements of API 6A and be of the material and hardness specified in API 6A.

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

5.2.7 All lines, crosses, valves, and fittings in the choke manifold system and the drill string safety valve shall be constructed from materials meeting applicable requirements of API 5L and API 6A.

5.2.8 With the exception of the drill string safety valves, the heat treating and other applicable requirements in NACE MR0175/ISO 15156, shall be implemented.

5.2.9 Field welding upstream of the chokes shall be kept to a minimum. Welding shall be performed in accordance with a written weld procedure specification (WPS), an approved procedure qualification record (PQR), and a welder/welding operator performance qualification (applicable for the weld type and position) in accordance with ASME *BPVC*, Section IX. All work processes, NDE inspection, and testing shall be performed in accordance with the requirements of NACE MR0175/ISO 15156.

5.2.10 Elastomeric components are also subject to H_2S attack. Nitrile elastomeric components that meet other requirements can be suitable for H_2S service provided drilling fluids are properly treated. Service life shortens rapidly as temperature increases from 150 °F to 200 °F (65.6 °C to 93 °C). In the event flowline temperatures in excess of 200 °F (93 °C) are anticipated, the equipment manufacturer shall be consulted.

5.2.11 Rubber elements shall be replaced if the BOP is activated and shut in for an emergency event during a sour well drilling operation or inspected and tested in accordance with equipment owner's PM program.

5.2.12 Changes prescribed by the equipment manufacturer to render equipment acceptable for service in a H_2S environment shall be considered. Consult the equipment manufacturer for any repairs or remanufacturing and replacement parts prior to the commencement of drilling operations.

5.2.13 Any time a BOP stack is subjected to an uncontrolled flow of reservoir fluids containing H_2S, the equipment user shall evaluate the level of servicing and testing required prior to that stack going back into service.

6 Surface BOP Systems

6.1 Surface BOP Stack Arrangements

6.1.1 Surface BOP Stack Pressure Designations

6.1.1.1 Every installed ram BOP shall have, as a minimum, a working pressure equal to the maximum anticipated surface pressure (MASP) to be encountered.

6.1.1.2 Blowout preventer equipment is based on rated working pressures (RWPs) and designated as described in Table 1.

Table 1—Surface BOP Pressure Designations

Pressure Designation	Rated Working Pressure
2K	2,000 psi (13.79 MPa)
3K	3,000 psi (20.68 MPa)
5K	5,000 psi (34.47 MPa)
10K	10,000 psi (68.95 MPa)
15K	15,000 psi (103.42 MPa)
20K	20,000 psi (137.90 MPa)
25K	25,000 psi (172.37 MPa)
30K	30,000 psi (206.84 MPa)

6.1.2 BOP Stack Classifications

6.1.2.1 The classification or "class" of a BOP stack is the total number of ram and annular preventers in the BOP stack.

6.1.2.2 The ram and annular preventer positions and outlets on the BOP stack shall provide reliable means to handle potential well control events. The system shall provide a means to:

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

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

c) strip the drill string.

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

6.1.2.4 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 identifying two annular preventers installed).

6.1.2.5 The final alphanumeric designation shall be assigned to the quantity of rams or ram cavities, regardless of their use, installed in the BOP stack. 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 system installed with two annular and four ram type preventers is designated as "Class 6-A2-R4."

6.1.2.6 Annular preventers having a lower RWP than ram preventers are acceptable.

6.1.2.7 A documented risk assessment shall be performed by the operator for all classes of BOP arrangements to identify ram placements and configurations to be installed. This assessment shall include tapered strings, casings, completion equipment, test tools, etc.

6.1.2.8 A minimum of one set of blind rams or blind shear rams (BSRs) shall be installed when ram-type preventers are to be installed. This requirement shall also apply to 3K or lesser-rated working pressure systems and a minimum Class 2 BOP stack arrangement.

6.1.2.9 A minimum of a Class 3 stack arrangement with one set of blind or blind shear rams and pipe rams shall be installed for a 5K pressure rated system. The third device may be a ram or annular type preventer, whichever is desired.

6.1.2.10 The minimum stack arrangement for Class 4 BOPs shall include one annular, one blind ram or BSR, and one pipe ram. The fourth device may be a ram or annular type preventer, whichever is desired.

6.1.2.11 A minimum Class 4 BOP stack arrangement shall be installed for 10K pressure rated systems, with a minimum of one blind ram or a BSR capable of shearing and sealing the drill pipe in use.

6.1.2.12 A Class 5 BOP arrangement or greater shall be installed for 15K and greater pressure rated systems. The minimum requirements for a Class 5 BOP stack arrangement shall include one annular, one BSR, and two pipe rams. The fifth device may be a ram or annular type preventer, whichever is desired. A risk assessment shall be performed to identify ram placements and configurations, and taking into account annular and large tubular(s) for well control management.

6.1.2.13 The minimum stack arrangement for Class 6 BOPs shall include one annular, one blind shear ram, and two pipe rams in the arrangement. The remaining devices may be a ram (pipe, blind, blind shear, casing shear, test, or variable), or annular-type preventer, or a combination thereof, as determined by a risk assessment.

6.1.2.14 Rig-specific stack identifying nomenclature (choke line, kill line, rams, and annulars, etc.) shall be made part of the drilling program.

6.1.3 Ram Locks

All sealing ram-type preventers shall be equipped with locking devices.

6.1.4 Storage of Replacement Parts and Assemblies

6.1.4.1 When storing BOP replacement parts and assemblies and related equipment, the parts and assemblies shall be coated and maintained with a protective coating to prevent rust.

6.1.4.2 The equipment manufacturer shall be consulted regarding replacement parts and assemblies storage requirements.

6.1.4.3 Elastomer storage shall be in accordance with 4.12.

6.1.4.4 If replacement parts and assemblies are acquired from a non-OEM, the parts and assemblies shall be equivalent or superior to the original equipment and fully tested, design verified, and supported by traceable documentation in accordance with relevant API specifications.

6.1.5 Spacer Spools

6.1.5.1 Spacer spools are used to provide separation between two drill-through components with equal sized end connections (nominal size designation and pressure rating).

6.1.5.2 Spacer spools may be used to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations but may serve other purposes in a stack as well.

6.1.5.3 Spacer spools for BOP stacks shall meet the following minimum specifications:

a) have a vertical bore diameter the same internal diameter as the mating equipment;

b) have a RWP equal to or greater than the RWP of the mating equipment;

c) shall not have any penetrations capable of exposing the wellbore to the environment.

6.1.6 Drilling Spools

6.1.6.1 Choke and kill lines may be connected either to side outlets of the BOPs or to a drilling spool installed below at least one BOP capable of closing on pipe.

6.1.6.2 Utilization of the ram-type BOP side outlets reduces the number of stack connections and overall BOP stack height. However, a drilling spool is used to provide stack outlets (to localize possible erosion in the dispensable spool) and to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations.

6.1.6.3 Drilling spools for BOP stacks shall meet the following minimum qualifications.

a) Pressure rated arrangements of 3K and 5K shall have two side outlets no smaller than a 2 in. (5.08 cm) nominal diameter and be flanged, studded, or hubbed.

b) Pressure rated arrangements of 10K and greater shall have two side outlets, one 3 in. (7.62 cm) and one 2 in. (5.08 cm) nominal diameter as a minimum, and be flanged, studded, or hubbed.

c) Drilling spools shall have 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.

d) Drilling spools shall have a RWP equal to the RWP of the installed ram BOP.

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

6.2 Choke Manifolds, Choke Lines, and Kill Lines—Surface BOP Installations

6.2.1 General

6.2.1.1 Choke and kill equipment shall be in accordance with the edition of API 16C that was in effect at the time of manufacture.

Newer editions should be used for modifications, re-manufactured equipment, or replacement equipment.

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

6.2.1.3 A choke manifold assembly shall include two adjustable chokes and may include the following:

a) manifolded choke and kill lines to permit pumping or flowing through either line;

b) the ability to tie into both drilling fluid and cement unit pump systems.

6.2.2 Surface BOP Choke Manifolds

6.2.2.1 Manifold equipment subject to well and/or pump pressure (upstream of and including the choke) shall have a minimum working pressure equal to the RWP of the ram BOPs, or the wellhead, whichever is lower. This equipment shall be tested in accordance with provisions of Table 2 and Table 3.

6.2.2.2 For working pressures of 3000 psi (20.68 MPa) and greater, flanged, welded, and clamped connections (as well as OECs), that are in accordance with API 6A and API 16A, shall be employed on components subjected to well pressure.

6.2.2.3 The choke manifold shall be placed in a readily accessible location.

6.2.2.4 Minimum nominal 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

6.2.2.5 Buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines. When buffer tanks are employed, provision shall be made to direct the flow path and to isolate a failure or malfunction of the buffer tank.

6.2.2.6 All choke manifold valves shall be full bore and full opening.

6.2.2.7 BOP or drilling spool outlet(s) connected to the choke or kill line shall have two full-opening valves. On the choke line, one of these two valves shall be remotely controlled.

If a component is used to connect the BOP or drilling spool outlet to the valves:

— the equipment owner's PM program shall include an inspection of the component for erosion at least every two years, and

— use of the outlet below the lower most ram BOP to take returns should be avoided.

6.2.2.8 A minimum of one remotely operated choke shall be installed on all 5K choke manifold systems.

6.2.2.9 A minimum of two remotely operated chokes shall be installed on choke manifold systems rated 10K and greater. The choke control panel shall have two independent control valves, one each for the two remotely operated chokes.

6.2.2.10 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.

6.2.2.11 Figure 1, Figure 2, and Figure 3 illustrate examples of choke manifolds for various working pressures. Additional hydraulic valves and choke runs, wear nipples downstream of chokes, redundant pressure gauges or measuring devices, and/or manifolding of vent lines can be dictated by the conditions anticipated for a particular well.

6.2.2.12 Materials used in construction and installation shall be suitable for the expected service, in accordance with API 16C.

6.2.2.13 The manifold and piping shall be protected from freezing.

6.2.2.14 It is acceptable for gauges used during the course of normal operations to read full scale and not serve as a test gauge.

6.2.2.15 Electronic pressure gauges and chart recorder or data acquisition systems shall be used within the manufacturer's specified range.

6.2.2.16 Pressure measurement devices (other than analog gauges) shall be calibrated per OEM procedures annually.

6.2.2.17 Calibration of gauges shall be traceable to a recognized national standard (e.g. NIST and ANSI).

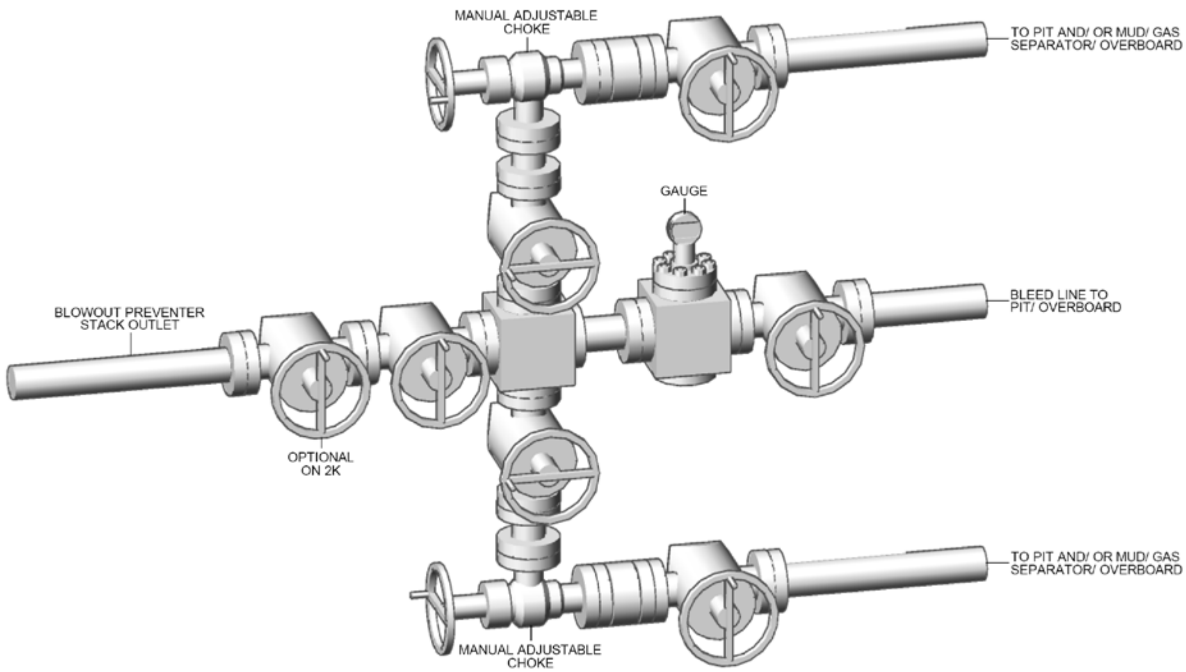

Figure 1—Example Choke Manifold Assembly for 2K and 3K Rated Working Pressure Service—Surface BOP Installations

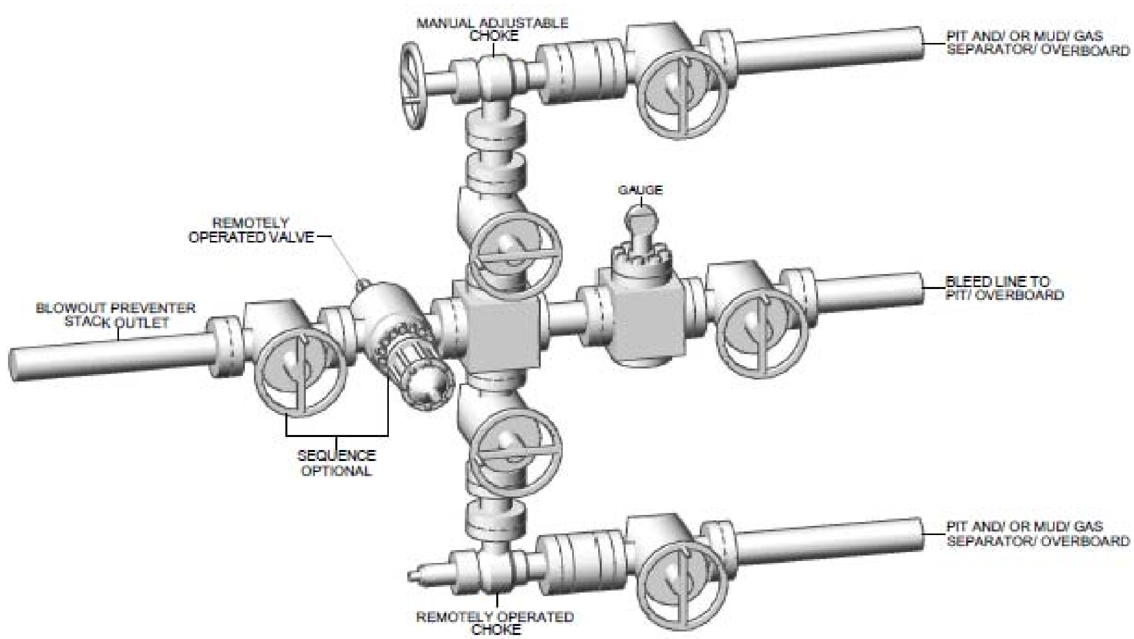

Figure 2—Example Choke Manifold Assembly for 5K Rated Working Pressure Service—Surface BOP Installations

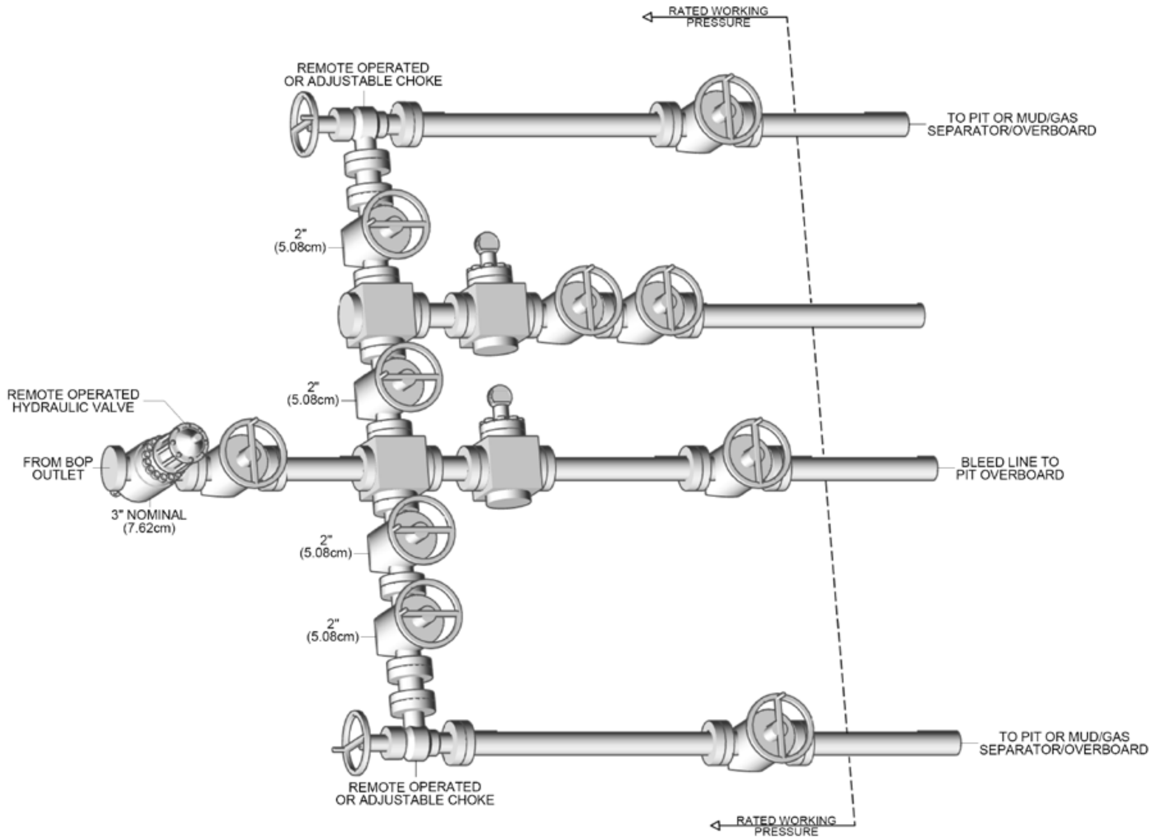

Figure 3—Example Choke Manifold Assembly for 10K or Greater Rated Working Pressure Service—Surface BOP Installations

6.2.2.18 The choke control station shall include all instruments necessary to furnish an overview of the well control operations. This includes the ability to monitor and control such items as standpipe pressure, casing pressure, and monitor pump strokes.

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

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

6.2.3 Surface BOP Choke Line Installation

6.2.3.1 Choke Line Bends

6.2.3.1.1 Choke lines should be as straight as possible because erosion at bends is possible during operations.

6.2.3.1.2 Block ells and tees should be targeted or have fluid cushions installed in the direction of flow, or in both directions if bidirectional flow is expected.

If pipe bends with $R/d < 10$ are used without targets or fluid cushions installed in the direction of expected flow or in both directions if bidirectional flow is expected, the equipment owner's PM program shall include an inspection for erosion at the pipe bends at least every two years, where:

R is the radius of pipe bend measured at the centerline in inches (centimeters);

d is the ID of the pipe in inches (centimeters).

6.2.3.1.3 For large radius pipe bends ($R/d \geq 10$), targets or fluid cushions may not be necessary.

6.2.3.1.4 See API 16C for equipment-specific requirements for flexible line assemblies.

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

6.2.3.2 Other Considerations for Choke Lines

6.2.3.2.1 Choke lines shall be secured to withstand the dynamic effect of fluid flow and the impact of drilling solids. Supports and fasteners located at points where piping changes direction shall be capable of restraining pipe deflection. Special attention should be paid to the end sections of the line to prevent line whip and vibration.

6.2.3.2.2 Based on erosion velocity and other considerations, the choke system shall be sized in accordance with the following.

a) For 2K, 3K, and 5K pressure rated systems, the minimum size for choke lines is 2 in. (5.08 cm) nominal diameter. For 10K and greater pressure rated systems, the minimum size is 3 in. (7.62 cm) nominal diameter.

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

6.2.4 Surface BOP Kill Line Installation

6.2.4.1 General

6.2.4.1.1 The kill line connects the drilling fluid pumps to a side outlet on the BOP stack and provides a means of pumping into the wellbore when the normal method of circulating down through the kelly or drill pipe cannot be employed.

6.2.4.1.2 The minimum configuration shall consist of two full-bore manual valves plus a check valve, or two full-bore valves (one of which is remotely operated) between the stack outlet and the kill line for installations with RWP of 5000 psi (34.47 MPa) or greater. For systems of 3000 psi (20.68 MPa) and less, two full-bore manual operated valves shall be installed.

6.2.4.1.3 The kill line shall be 2 in. (5.08 cm) nominal diameter or larger.

6.2.4.1.4 Figure 4, Figure 5, and Figure 6 illustrate example kill line installations for various working pressure service.

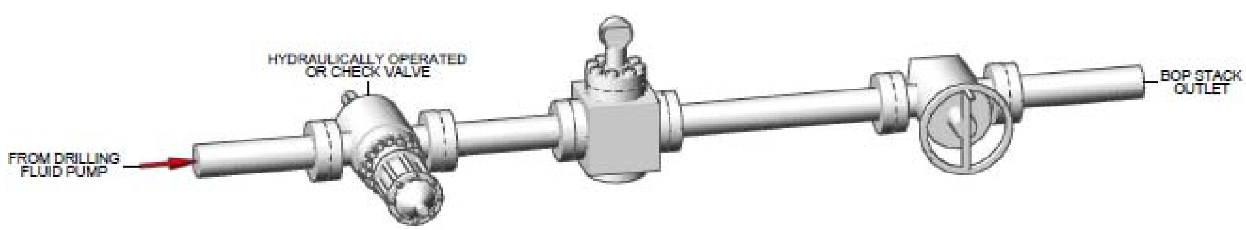

Figure 4—Example Kill Line Assembly for 2K and 3K Rated Working Pressure Service—Surface BOP Installations

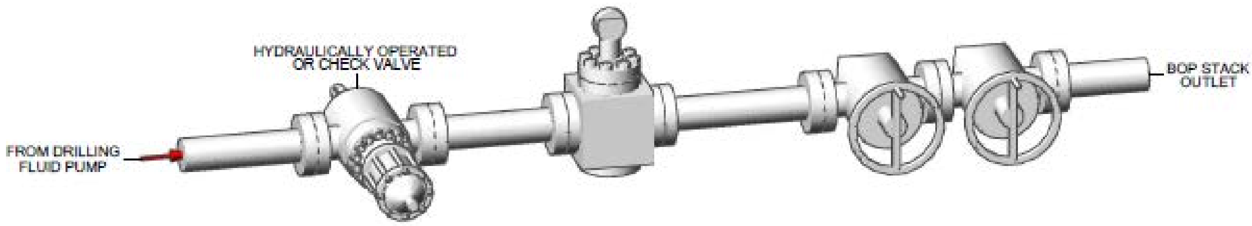

Figure 5—Example Kill Line Assembly for 5K and Greater Rated Working Pressure Service—Surface BOP Installations

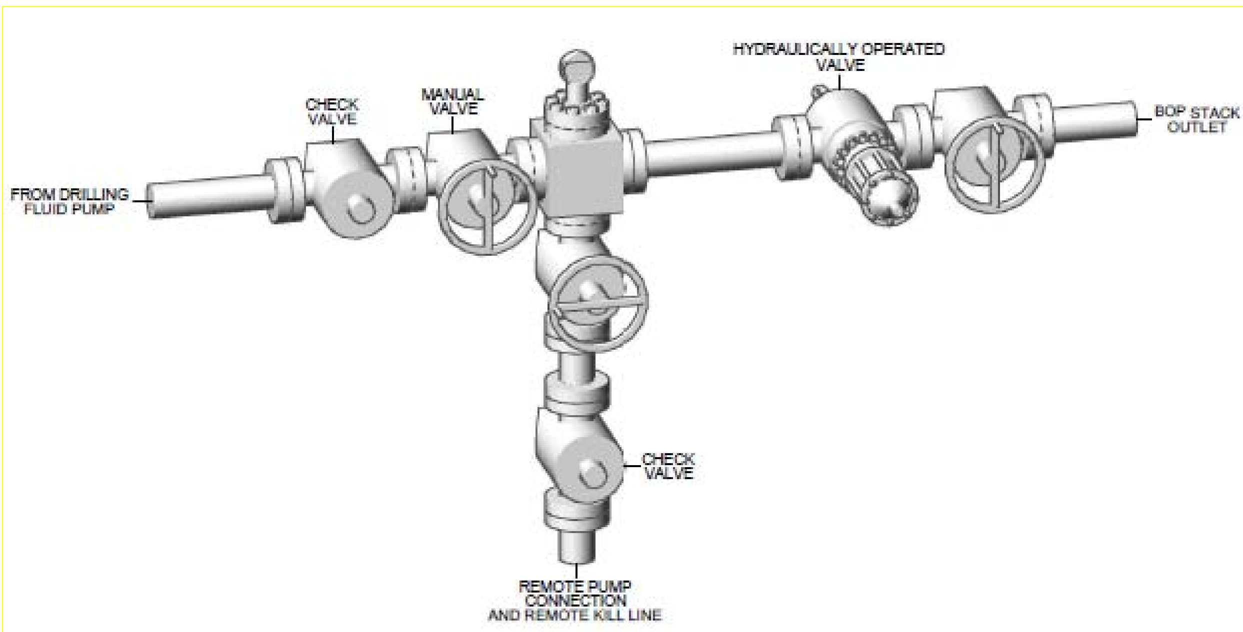

Figure 6—Example Kill Line Assembly for 5K and Greater Rated Working Pressure Service—Surface BOP Installations

6.2.4.2 Kill Line Bends

6.2.4.2.1 Kill lines should be as straight as possible because erosion at bends is possible during operations.

6.2.4.2.2 Block ells and tees shall be targeted or have fluid cushions installed in the direction of flow, or in both directions if bidirectional flow is expected.

If pipe bends with R/d < 10 are used without targets or fluid cushions installed in the direction of expected flow or in both directions if bidirectional flow is expected, the equipment owner's PM program shall include an inspection for erosion at the pipe bends at least every two years, where

R is the radius of pipe bend measured at the centerline in inches (centimeters);

d is the ID of the pipe in inches (centimeters).

6.2.4.2.3 For large radius pipe bends ($R/d \geq 10$), targets are generally unnecessary.

6.2.4.2.4 See API 16C for equipment-specific requirements for flexible kill lines and articulated line assemblies.

6.2.4.2.5 For flexible lines, consult the manufacturer's guidelines on working MBR to ensure proper length determination and safe working configuration.

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

6.2.4.3 Other Considerations for Kill Lines

6.2.4.3.1 A documented risk assessment to determine the type and placement of valves (hydraulic, manual, and/or check) for the kill line shall be performed.

6.2.4.3.2 The location of the stack kill line connection depends on the particular configuration of BOPs and spools employed.

6.2.4.3.3 On high-pressure critical wells a remote kill line may be employed to permit use of an auxiliary high-pressure pump if the rig pumps become inoperative or inaccessible. This line should be connected to the kill line near the BOP stack and extended to an auxiliary high-pressure pump at a location affording maximum safety and accessibility.

6.2.4.3.4 The same guidelines that govern the installation of choke manifolds and choke lines should apply to kill line installations. See Figure 4, Figure 5, and Figure 6 for examples of kill manifold installations at various RWPs and API 16C for equipment specifications for kill lines.

6.2.4.3.5 The kill line shall be protected from freezing.

6.2.4.3.6 The kill line shall not be used as a fill-up line.

6.2.5 Inspection, Testing, and Maintenance of Choke Manifolds, Choke Lines, and Kill lines

6.2.5.1 Maintenance and inspection shall be performed on the same schedule employed for the BOP in use and shall include checks for wear, erosion, and plugged or damaged lines.

6.2.5.2 The frequency of maintenance and inspection will depend upon usage. See Table 2 and Table 3 for testing, inspection, and general maintenance of kill manifold systems.

6.3 Control Systems for Surface BOP Stacks

6.3.1 General

6.3.1.1 Control systems for surface BOP stacks shall be in accordance with the edition of API 16D that was in effect at the time of the control system manufacture.

Newer editions should be used for modifications, remanufactured equipment or replacement equipment.

6.3.1.2 The purpose of the BOP control system is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

6.3.1.3 BOP control systems for surface installations (land rigs, offshore jackups, and platforms) provide hydraulic power fluid in a return-to-tank circuit as the actuating medium.

6.3.1.4 The minimum required components of the BOP control system shall include the following:

a) control fluid (hydraulic power fluid, closing unit fluid);

b) control fluid reservoir;

c) control fluid mixing system (if applicable);

d) pump systems;

e) accumulator system;

f) control system valves, fittings, and components;

g) control stations.

6.3.2 Control Fluid

6.3.2.1 A suitable control fluid shall be used as the control system operating fluid.

6.3.2.2 Control fluid shall be selected and maintained to meet minimum BOP equipment OEM(s) and fluid supplier properties, and equipment owner requirements.

6.3.2.3 Sufficient volume of glycol shall be added to any closing unit fluid containing water if ambient temperatures below 32 °F (0 °C) are anticipated.

6.3.2.4 Diesel oil, kerosene, motor oil, chain oil, or any other similar fluid shall not be used as a control fluid because of the possibility of explosions or resilient seal damage.

6.3.3 Control Fluid Reservoir

6.3.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

6.3.3.2 To prevent overpressurization, vents shall be inspected and maintained to ensure they are not plugged or capped.

6.3.3.3 Batch mixing fluid is acceptable or filling the reservoir with control fluid not requiring mixing is also acceptable.

6.3.3.4 All reservoir instrumentation shall be tested in accordance with equipment owner PM program to ensure they are in proper working order.

6.3.3.5 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner's PM program to ensure indication of fluid level in each of the individual reservoirs are in proper working order.

6.3.4 Control Fluid Mixing System (If Applicable)

6.3.4.1 The control fluid mixing system shall be tested to ensure proper functionality of the automatic operating system.

6.3.4.2 The automatic mixing system should be tested to ensure it is manually selectable over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

6.3.4.3 A manual override of the automatic mixing system (if installed) should be tested to ensure proper operation.

6.3.5 Pump Systems

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

6.3.5.2 Each pump system shall have an independent power source. These pump systems shall be connected so that the loss of any one power source does not impair the operation of all of the pump systems.

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

6.3.5.4 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.

6.3.5.5 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 system RWP within 30 minutes.

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

6.3.5.7 Each pump system shall provide a discharge pressure at least equivalent to the control system working pressure.

6.3.5.8 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system RWP and automatically stop between 97 % to 100 % of the RWP.

6.3.5.9 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system RWP and automatically stop between 95 % to 100 % of the system RWP.

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

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

— 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;

— the second device, such as a certified relief valve, to limit the pump discharge pressure and flow in accordance with API 16D.

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

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

6.3.6 Hydraulic Control Unit Location

6.3.6.1 The hydraulic control unit shall meet the classification requirements for the area in which it is installed and should be outside the rig substructure. See API 500 and API 505 for information on area classification.

6.3.6.2 The hydraulic control unit should be installed in a location that minimizes drainage or flow back from the operating lines to the reservoir. If the hydraulic control units are located at a distance from or below the BOP stack that will affect closing response times, additional reservoir volume or alternative means shall be provided to compensate for flow back in the closing lines.

6.3.7 Accumulator Systems

6.3.7.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions. This is achieved by the hydraulic compression of an inert gas with the hydraulic power unit (HPU).

6.3.7.2 Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

6.3.7.3 A nonoxidizing (inert) gas with low flammability, such as nitrogen or helium, shall be used for precharging surface accumulators. Neither atmospheric air nor oxygen shall be used.

6.3.7.4 The gas used shall be in accordance with the accumulator design.

6.3.8 Control System Response Time

6.3.8.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal.

6.3.8.2 Measurement of closing response time begins when the close function is activated, at any control panel, and ends when the BOP or valve is closed affecting a seal.

6.3.8.3 A BOP may be considered closed when the regulated operating pressure has initially recovered to its nominal setting or other demonstrated means.

6.3.8.4 The BOP control system shall be capable of closing each ram BOP in 30 seconds or less.

6.3.8.5 Closing time shall be 30 seconds or less for annular BOPs smaller than 18 $^3/_4$ in. nominal bore and 45 seconds or less for annular preventers of 18 $^3/_4$ in. nominal bore and larger.

6.3.8.6 Response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

6.3.8.7 Closing time shall be 30 seconds or less for non-sealing shear rams.

6.3.9 Accumulator Precharge

6.3.9.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions.

6.3.9.2 The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

6.3.9.3 Rapid discharge for dedicated shear systems shall take into account temperature effects on the precharge gas (see Annex C).

6.3.9.4 The precharge pressure shall be measured prior to BOP stack deployment and adjusted in accordance with the manufacturer-specified API 16D method (A, B, or C), using the control system manufacturer-supplied surface base pressure, adjusted for operating temperature as required, and shall be documented and retained at the rig site. The calculated precharge pressures along with documentation supporting nonoptimal precharge pressures (if used) shall be filed with the well-specific data package. See Annex C for examples of accumulator precharge calculations.

6.3.9.5 The precharge pressure calculations shall take into account the well-specific conditions (e.g. drill pipe shear pressure, temperature, etc.).

6.3.9.6 The design of the BOP, mechanical properties of drill pipe and wellbore pressure may necessitate higher closing pressures for shear operations.

6.3.10 Accumulators, Valves, Fittings, and Pressure Gauge Requirements

6.3.10.1 See 6.5.3.6 for test gauges used for testing and maintenance.

6.3.10.2 No accumulator bottle shall be operated at a pressure greater than its RWP. There is an increased risk of damage to the bladder if the precharge pressure is less than 25 % of the system hydraulic pressure.

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

6.3.10.4 The accumulator system shall be installed such that the loss of an individual accumulator and/or bank will not result in more than 25 % loss of the total accumulator system capacity.

6.3.10.5 Supply-pressure isolation valves and bleed-down valves shall be provided on each accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

6.3.10.6 All control system analog pressure gauges shall be calibrated to 1 % of full scale at least every 3 years.

6.3.10.7 Electronic pressure gauges and chart recorder or data acquisition systems shall be used within the manufacturer's specified range.

6.3.10.8 A pressure gauge for measuring the accumulator precharge pressure shall be available. Those pressure gauges shall be calibrated to 1 % of full scale (e.g. 100 psi full scale on 10K gauge or +/− 50 psi) and used to not less than 25 % or more than 75 % of the full pressure span of the gauge.

EXAMPLE A 5000 psi (34.47 MPa) pressure gauge should be used to measure pressures between 1250 psi (8.62 MPa) and 3750 psi (25.86 MPa) .

6.3.11 Control System Valves, Fittings, and Components

6.3.11.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a working pressure at least equal to the RWP of their respective circuit.

6.3.11.2 Conformity of Piping Systems

6.3.11.2.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

6.3.11.2.2 Pipe, pipe fittings, and components shall conform to specifications of ASME B31.3.

6.3.11.2.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

6.3.11.2.4 Welding shall be performed in accordance with a written WPS, written and qualified in accordance with ASME *BPVC*, Section IX.

6.3.11.2.5 All rigid or flexible lines between the control system and BOP stack shall meet the fire test requirements of API 16D, including end connections, and shall have RWP equal to the RWP of the BOP control system.

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

6.3.11.2.7 The control system shall be equipped to allow isolation of the pumps, thus allowing maintenance and repair work without affecting the functionality and operability of the remainder of the system.

6.3.11.2.8 Supply-pressure isolation valves and bleed down valves shall be provided on each accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir, without affecting the functionality and operability to the remainder of the system.

6.3.11.2.9 The control system shall be equipped and maintained with measurement devices to indicate

a) accumulator pressure,

b) regulated manifold pressure,

c) regulated annular pressure, and

d) air supply pressure.

6.3.11.2.10 The control system shall be equipped with a separate pressure regulator to permit manual control of the annular preventer operating pressure.

6.3.11.2.11 The control system shall be equipped with a pressure regulator to control the operating pressure on the ram BOPS.

6.3.11.2.12 Pressure regulators used for control of BOP systems shall be unaffected by loss of signal.

6.3.11.2.13 The control system shall be capable of providing the required shear pressure.

6.3.11.2.14 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.).

6.3.12 Control Stations

6.3.12.1 The control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations

6.3.12.2 All control stations shall meet the classification requirements for the area in which they are installed. See API 500 and API 505 for information on area classification.

6.3.12.3 One control station location shall provide easy accessibility for the drill crew.

6.3.12.4 The other control station shall be placed away from the rig floor to provide safe access for functioning the BOPs during an emergency well control event.

6.3.12.5 The control valve handle that operates the blind, or blind-shear, rams shall be protected to avoid unintentional operation but still allow full operation from the remote panel without interference.

6.3.12.6 Additional remote panels that do not have full BOP functionality at secondary locations (e.g. muster points or life boat stations) may be used to supplement the two other full-function panels.

6.4 Auxiliary Equipment

6.4.1 Kelly Valves

6.4.1.1 The kelly cock is installed between the swivel and the kelly.

6.4.1.2 A lower kelly valve is installed immediately below the kelly.

6.4.1.3 A minimum of two kelly valves shall be required, with the bottom valve being capable of use for stripping operations. The size of the valve and the hole/casing in use for stripping operations shall be considered.

NOTE 1 This valve can be closed under pressure to remove the kelly and can be stripped into the hole if a closed inside blowout preventer (IBOP) valve is installed above it.

NOTE 2 Some lower kelly valve models are not designed to withstand external pressure encountered in stripping operations.

6.4.2 Drill Pipe Safety Valve

6.4.2.1 A drill pipe safety valve shall be readily available (i.e. stored in open position with wrench accessible) on the rig floor at all times.

6.4.2.2 This valve(s) and crossover sub(s) shall be equipped to screw into any drill string member in use.

6.4.2.3 The outside diameter (OD) of the drill pipe safety valve shall be suitable for running into the hole.

6.4.3 Inside Blowout Preventer

6.4.3.1 An IBOP valve shall be available for use when stripping the drill string into or out of the hole.

6.4.3.2 The valve(s), crossover sub(s), or profile nipple shall be equipped to screw into any drill string member in use.

6.4.4 Field Testing

The kelly valves, drill pipe safety valve, and IBOP shall be tested in accordance with Table 2 and Table 3.

6.4.5 Drill String Float Valve

6.4.5.1 A float valve is placed in the drill string to prevent upward flow of fluid or gas inside the drill string. The float valve is a special type of backpressure or check valve. A float valve in good working order will prohibit backflow through the drill string and allow for safe installation of the safety valves.

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

a) The flapper-type float valve offers the advantage of having an opening through the valve that is approximately the same ID as that of the tool joint. This valve will permit the passage of balls, or go-devils, which may be required for operation of tools inside the drill string below the float valve.

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

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

6.4.6 Trip Tank

6.4.6.1 A trip tank shall be installed and used on all wells.

6.4.6.2 A trip tank is a low-volume, 100 barrel (15.9 m^3) or less, calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well.

6.4.6.3 A trip tank may be of any shape, provided the capability exists for reading the volume contained in the tank at any liquid level.

6.4.6.4 The trip tank volume readout may be direct or remote, preferably both.

6.4.6.5 The size and configuration of the tank should be such that volume changes of approximately one-half barrel can be easily detected by the readout arrangement.

6.4.6.6 Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations.

6.4.6.7 Other uses of the trip tank include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following a cement job, calibrating drilling fluid pumps, etc.

6.4.6.8 The trip tank is also used to measure the volume of drilling fluid bled from or pumped into the well as pipe is stripped into or out of the well.

6.4.7 Pit Volume Measuring and Recording Devices

6.4.7.1 Pit volume measuring systems, complete with audible and visual alarms, shall be installed. These systems transmit a signal from sensors in the drilling fluid pits to instrumentation on the rig floor. These are valuable in detecting fluid gains or losses.

6.4.7.2 Audible and visual alarms shall be active during well operations.

6.4.7.3 A pit volume totalizer system shall be installed and used on all rigs.

6.4.8 Flow Rate Sensor

6.4.8.1 A flow rate sensor mounted in the flow line shall be installed for early detection of formation fluid entering the wellbore or a loss of returns.

6.4.8.2 Audible and visual alarms shall be active during well operations.

6.4.9 Poor Boy Degasser and Mud/Gas Separator

6.4.9.1 There are two basic types of mud/gas separation systems in use in the industry, poor boy degasser and the mud/gas separator. The most common system is the atmospheric poor boy degasser (or gas buster), which separates gas from the drilling fluid that is gas cut and vents the gas away from the rig.

6.4.9.2 The mud/gas separator is designed such that it can be operated at a moderate backpressure, less than 100 psi (0.69 MPa) or at the gas vent line pressure (atmospheric) plus line friction pressure drop.

6.4.9.3 The dimensions of the system are critical in that they define the volume of gas and fluid that the system can effectively handle.

6.4.9.4 There are advantages and disadvantages to either the atmospheric or pressurized systems. The following are common to both systems:

a) a means of venting or relieving pressure shall be provided in case of a malfunction or in the event the capacity of the system is exceeded;

b) precautions shall also be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the wall of the vessel;

c) provisions shall be made for easy clean out of the vessels and lines in the event of plugging;

d) neither system is recommended for well production testing operations.

6.4.10 Mechanical Type Degasser

6.4.10.1 A mechanical type degasser may be used to remove entrained gas bubbles in the drilling fluid that are too small to be removed by the poor boy separator. Most mechanical type degassers make use of some degree of vacuum to assist in removing this entrained gas.

6.4.10.2 The drilling fluid discharge line from the poor boy separator should be placed close to the drilling fluid inlet line to the mechanical type degasser to reduce the possibility of gas breaking out of the drilling fluid in the pit.

6.4.11 Flare/Vent Lines

6.4.11.1 All flare/vent lines should be as long as practical with provisions for flaring during varying wind directions.

6.4.11.2 Flare/vent lines should be as straight as possible and should be securely anchored.

6.4.11.3 For H_2S operations, the top of the flare lines shall be equipped with an igniter or some means of flaring the gas.

6.4.12 Standpipe Choke

If installed, an adjustable choke mounted on the rig standpipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed-off pressure between BOPs during stripping operations, etc. See Figure 7 for an example standpipe choke installation.

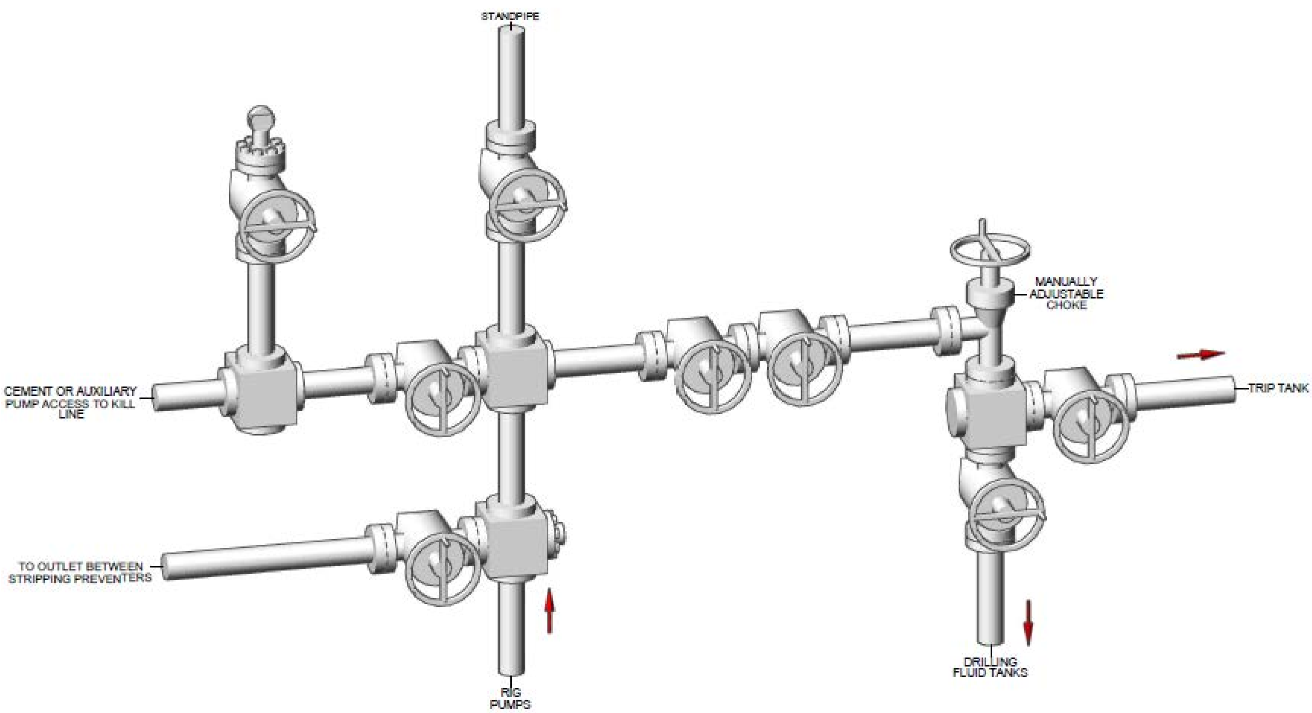

Figure 7—Example Standpipe Choke Installation

6.4.13 Top Drive Equipment

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

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

a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve;

b) most top drive manual valves cannot be stripped into 7 5/8 in. (19.37 cm) or smaller casing;

c) once the top drive's manual valve is disconnected from the top drive, another valve and crossover may be required.

6.5 Maintenance and Testing—Surface BOP Systems

6.5.1 Purpose

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

a) that specific functions are operationally ready,

b) the pressure integrity of the installed equipment, and

c) the control system and BOP compatibility.

6.5.2 Types of Tests

6.5.2.1 General

6.5.2.1.1 Test programs incorporate visual inspections, function and pressure tests, maintenance practices, and drills.

6.5.2.1.2 A visual inspection should be performed, in accordance with equipment owner's PM program. Operability and integrity can be confirmed by function and pressure testing.

6.5.2.1.3 Site-specific procedures for tests on well control equipment shall be incorporated into acceptance tests, installation and subsequent tests, drills, periodic operating tests, maintenance practices, and drilling and/or completion operations.

6.5.2.1.4 Manufacturer operating and maintenance documents, equipment owner PM programs, and operating experiences shall be incorporated into the site-specific procedures.

6.5.2.2 Inspection Test

6.5.2.2.1 Inspection practices and procedures vary and are outside the scope of this document.

6.5.2.2.2 Inspection tests may include, but are not limited to, visual, dimensional, audible, hardness, functional, and pressure tests. Inspection test is a collective term used to state the various procedural examination(s) of flaws that can influence equipment performance.

6.5.2.2.3 Inspections of the choke, kill lines, valves and other well control assemblies shall be performed in accordance with the equipment owner's PM program for wear, erosion, plugging, or other damages.

6.5.2.3 Function Test

A function test is the operation of a piece of equipment or a system to verify its intended operation. Function testing may or may not include pressure testing.

6.5.2.4 Pressure Test

6.5.2.4.1 A pressure test is the periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system.

6.5.2.4.2 Pressure test programs for the wellhead and casing shall be prescribed by the equipment user on an individual well basis.

6.5.2.5 Hydraulic Chamber Test

A hydraulic chamber test is the application of a pressure test to any hydraulic operating chamber specified by the manufacturer for such items as:

— BOP operator cylinders and bonnet assemblies; and

— hydraulic valve actuators, etc.

6.5.2.6 Crew Drills

The proficiency with which drilling crews operate the well control equipment is as important as the operational condition of the equipment. See API 59 for more information on crew drills and well control rig practices.

6.5.2.7 Crew Competency

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

6.5.3 Test Criteria

6.5.3.1 Function Tests

6.5.3.1.1 As operations allow, all operational components of the BOP equipment systems shall be function tested at least once a week to verify the component's intended operations. Function tests may or may not include pressure tests.

6.5.3.1.2 The pressure tests qualify as function tests.

6.5.3.1.3 Function tests shall be performed weekly, alternating from the driller's panel, remote panels or control stations, where all BOP functions are included (see sample worksheets in Annex A).

6.5.3.1.4 Remote panels where all BOP functions are not included (e.g. life boat panels), shall be function tested upon the initial BOP tests and monthly thereafter.

6.5.3.1.5 Actuation times shall be recorded in a database for evaluating trends (see sample worksheets in Annex A).

6.5.3.1.6 A function test of the BOP control system shall be performed following the disconnection or repair, limited to the affected component.

6.5.3.2 Pressure Tests

6.5.3.2.1 All blowout prevention components that can be exposed to well pressure shall be tested first to a low pressure between 250 psi to 350 psi (1.72 MPa to 2.41 MPa) and then to a high pressure.

6.5.3.2.2 When performing the low-pressure test, do not apply a higher pressure and bleed down to the low test pressure. The higher pressure can initiate a seal that can continue to seal after the pressure is lowered, therefore misrepresenting a low-pressure condition.

6.5.3.2.3 A stabilized low and high test pressure shall be maintained for at least 5 minutes, with no visible leakage.

The allowable test pressure tolerance above rated working pressure shall be 5% of rated working pressure or 3.45 MPa (500 psi), whichever is less.

6.5.3.2.4 Initial pressure tests are defined as those tests that shall be performed on location before the equipment is put into operational service.

6.5.3.2.5 The initial high-pressure test on all components that can be exposed to well pressure (e.g. BOP stack, manifolds, lines and valves, IBOP, kelly valves and hoses, etc.) shall be tested in accordance with Table 2.

6.5.3.2.6 There can be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these shall be addressed in the site-specific well control pressure test program.

6.5.3.2.7 Subsequent high-pressure tests on the well control components shall be tested in accordance with Table 3.

6.5.3.2.8 With larger size annular BOPs some small movement could continue within the large rubber mass for prolonged periods after pressure is applied and may require longer holding periods.

6.5.3.2.9 Pressure shall be released only through pressure release lines and bleed valves.

6.5.3.2.10 Where possible, the return volume should be measured to confirm all pressure has been bled off. Where this is not possible, extreme caution shall be taken to ensure pressure is bled off safely.

6.5.3.2.11 Pressure test operations shall be alternately controlled from the various onsite control stations and panels.

6.5.3.2.12 All valves (except check valves) shall be low and high pressure tested in the direction of flow.

6.5.3.2.13 Valves that are required to seal against flow from both directions, shall be tested from both directions.

6.5.3.2.14 Check valves installed on the kill line shall be low and high pressure tested from the wellbore side.

6.5.3.2.15 Drifting the BOP shall be performed upon completion of the initial BOP test on the wellhead assembly. This may be achieved using the test plug, wear bushing tools, or other large bore tools. Subsequent drifting shall be determined by the equipment owner's PM program or well specific operations.

6.5.3.2.16 The minimum drift size for the BOP system in use, shall be determined by the equipment owner and user's requirements for the well(s) the equipment is installed upon.

6.5.3.3 Hydraulic Chamber Tests

6.5.3.3.1 Hydraulic chamber tests shall be performed in accordance with the manufacturer's recommended maximum operating pressure.

6.5.3.3.2 The hydraulic chamber tests shall be performed on both the opening and the closing chambers of the equipment installed and shall be documented.

6.5.3.3.3 When performing the chamber test, the pressure shall be stabilized for at least 5 minutes, with no visible leakage, to be considered an acceptable test result.

6.5.3.3.4 Subsequent pressure tests of closing unit systems shall be performed following the disconnection or repair of any operating pressure containment seal in the BOP control system, but limited to the affected component.

6.5.3.4 Pressure Test Frequency

6.5.3.4.1 Pressure tests on the well control equipment shall be conducted

a) before the equipment is put into operational service on the wellhead;

b) after the disconnection or repair of any pressure containment seal in the BOP stack, choke line, kill line, choke manifold, or wellhead assembly but limited to the affected component;

c) in accordance with the equipment owner's PM program; and

d) not to exceed intervals of 21 days.

6.5.3.4.2 Table 2 and Table 3 include a summary of the test pressures for surface BOP stacks and related well control equipment.

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

a) at least once yearly,

b) when equipment is repaired or remanufactured,

c) in accordance with equipment owner's PM program.

6.5.3.5 Test Fluids

6.5.3.5.1 Well control equipment shall be pressure tested with water or water with additives.

6.5.3.5.2 Air should be removed from the system before test pressure is applied.

6.5.3.5.3 Control systems and hydraulic chambers shall be tested using clean control system fluids with lubricity and corrosion additives for the intended service and operating temperatures.

6.5.3.6 Test Pressure Measurement Devices

6.5.3.6.1 Test pressure gauges and chart recorders or data acquisition systems shall be used and all testing results shall be recorded.

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

6.5.3.6.3 Electronic pressure gauges and chart recorder or data acquisition systems shall be used within the manufacturer's specified range.

6.5.3.6.4 Test pressure measurement devices (including analog gauges) shall be calibrated annually in accordance with OEM procedures.

6.5.3.6.5 Calibrations shall be traceable to a recognized national standard (NIST and ANSI).

6.5.3.6.6 It is acceptable for gauges to be used during the course of normal operations to read full scale but shall not serve as a test gauge.

6.5.3.7 Test Documentation

6.5.3.7.1 The results of all BOP equipment pressure and function tests shall be documented (see worksheet in Annex A).

6.5.3.7.2 Pressure tests shall be performed with a pressure chart recorder or equivalent data acquisition system and signed by pump operator, contractor's representative, and operating company representative.

6.5.3.7.3 Problems with the BOP equipment that results in an unsuccessful pressure test and actions to remedy the problems shall be documented.

6.5.3.7.4 The equipment owner shall inform the equipment manufacturer of any well control equipment that fails to perform in the field, in accordance with Annex B.

Table 2—Pressure Test, Surface BOP Systems, Initial Test

Component to Be Tested	Pressure Test—Low Pressure [a] psi (MPa)	Pressure Test—High Pressure [b c] psi (MPa)
Annular preventer	250 to 350 (1.72 to 2.41)	Lesser of 70 % of annular RWP, RWP of wellhead, or ram preventer test pressure.
Operating chambers	N/A	Maximum operating pressure recommended by the annular BOP manufacturer.
Ram preventers		
Fixed pipe	250 to 350 (1.72 to 2.41)	RWP of ram BOPs or RWP of the wellhead system, whichever is lower.
Variable bore		
Blind/blind shear		
Operating chamber	N/A	Maximum operating pressure recommended by the ram BOP manufacturer.
Choke and kill lines and valves	250 to 350 (1.72 to 2.41)	RWP of ram BOPs or RWP of the wellhead system, whichever is lower.
Operating chamber	N/A	Maximum operating pressure recommended by the valve manufacturer.
Choke manifold		
Upstream of choke(s)	250 to 350 (1.72 to 2.41)	RWP of ram BOPs, RWP of the wellhead system, or RWP choke(s) inlet, whichever is lower.
Downstream of choke(s)		RWP of choke(s) outlet, valve(s), or line(s), whichever is lower.
Adjustable chokes	Function test only; verification of backup system.	
BOP control system		
Manifold and BOP lines	N/A	Control system maximum operating pressure.
Accumulator pressure	Verify precharge.	N/A
Close time	Function test.	N/A
Pump capability		
Control stations		
Safety valves		
Kelly, kelly valves, and safety valves	250 to 350 (1.72 to 2.41)	RWP of components.
Auxiliary equipment		
Poor boy degasser/MGS [d]	In accordance with equipment owner's PM program.	Flow test.
Trip tank, flo-show, etc.	Visual and manual verification.	Flow test.

[a] The low-pressure test shall be stabilized for at least 5 minutes with no visible leaks. Flow-type test shall be of sufficient duration to observe for significant leaks.

[b] The high-pressure test shall be stabilized for at least 5 minutes with no visible leaks.

[c] Well control equipment may have a higher rated working pressure than required for the well site. The site-specific test requirements shall be used for these situations.

[d] The MGS requires a one-time hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed.

Table 3—Pressure Test, Surface BOP Systems, Subsequent Tests

Component to Be Tested	Pressure Test—Low Pressure [a] psi (MPa)	Pressure Test—High Pressure [b c] psi (MPa)
Annular preventer	250 to 350 (1.72 to 2.41)	Minimum of MASP for the hole section or 70 % of annular RWP, whichever is lower.
Ram preventers		
Fixed pipe	250 to 350 (1.72 to 2.41)	MASP of the hole section.
Variable bore		
Blind/blind shear		
Casing rams (prior to running casing)		
Choke and kill lines and valves		
Choke manifold		
Upstream of choke(s)	250 to 350 (1.72 to 2.41)	Same as the ram preventer.
Downstream of choke(s)	250 to 350 (1.72 to 2.41)	RWP of choke(s) outlet, valve(s), or line(s), whichever is lower.
Adjustable chokes	Function test only.	Verification of backup control system.
BOP control system		
Manifold and BOP lines	Function test in accordance with equipment owner's PM program.	In accordance with equipment owner's PM program.
Accumulator pressure	Function test in accordance with equipment owner's PM program.	
Close time	Verify functionality of backup systems.	
Pump capability		
Control stations		
Safety valves		
Kelly, kelly valves, and safety valves	250 to 350 (1.72 to 2.41)	MASP of the hole section.
Auxiliary equipment		
Poor boy degasser/MGS [d]	Optional flow test.	N/A
Trip tank, flo-show, etc.	Visual and manual verification.	Daily.

[a] The low-pressure test shall be stabilized for at least 5 minutes with no visible leaks. Flow-type test shall be of sufficient duration to observe for significant leaks.

[b] The high-pressure test shall be stabilized for at least 5 minutes with no visible leaks.

[c] Well control equipment may have a higher rated working pressure than required for the well site. The site-specific test requirements shall be used for these situations.

[d] The MGS requires a one-time hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed.

6.5.3.8 General Testing Considerations

6.5.3.8.1 All personnel shall be alerted when pressure test operations are to be conducted, when testing operations are underway, and when pressure testing has concluded.

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

6.5.3.8.3 Tightening, repair, or any other work shall be done only after verification that the pressure has been released and all parties have agreed that there is no potential of trapped pressure.

6.5.3.8.4 All lines and connections that are used in the test procedures shall be adequately secured.

6.5.3.8.5 All fittings, connections, and piping used in pressure testing operations shall have pressure ratings equal to or greater than the maximum anticipated test pressure.

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

6.5.3.8.7 When a BOP stack is tested on the wellhead, a procedure shall be available to monitor pressure on the casing if the test plug leaks.

6.5.3.8.8 Function tests of the remote panels using the uninterrupted backup power source and main BOP closing unit control panels shall include a simulated loss of primary power to the control unit and to the control panel. This system shall permit operation of all the surface control valves at least two (2) times after the loss of rig air and electric power.

6.5.3.8.9 Connection make-up shall be in accordance with Section 4.

6.5.4 Surface BOP Stack Equipment

6.5.4.1 The surface BOP stack equipment includes the wellbore pressure-containing equipment above the wellhead, including the ram BOPs, spool(s), annular(s), choke and kill valves, and lines to the choke manifold. Equipment above the uppermost BOP is not included.

6.5.4.2 The entire stack shall be pressure tested as a unit.

6.5.4.3 For the initial BOP test (upon installation) the annular(s) and variable-bore ram(s) (VBR) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

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

6.5.4.5 Subsequent pressure tests of the annular BOP(s) and VBR(s) shall be performed on the smallest size pipe to be used in the hole section and retested if smaller OD pipe is picked up.

6.5.4.6 Blind and/or blind shear ram BOPS shall not be tested when pipe is in the stack.

6.5.4.7 The capability of the shear ram and ram operator shall be verified with the BOP manufacturer for the planned drill pipe. The shear ram and preventer design and/or metallurgical differences among drill pipe manufacturers may require high closing pressures for shear operations.

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

6.5.4.9 During the initial test, the ram BOPs shall be pressure tested on the ram locks with the closing pressure bled to zero. Hand wheels for manual locks shall be installed ready and capable for operation.

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

6.5.4.11 The manufacturer's markings for BOP 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.

6.5.4.12 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for 6 months or longer and has not been preserved according to equipment owner guidelines.

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

6.5.4.14 A precharged surge bottle can be installed adjacent to the annular preventer if contingency well control procedures include stripping operations.

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

6.5.5 Chokes and Choke Manifolds

6.5.5.1 The choke manifold upstream of the chokes, including the last high-pressure valve, shall be tested to the same pressure as the ram BOPs (see Table 2 and Table 3).

6.5.5.2 The adjustable chokes shall be operated daily to verify operability. Choke manifold valves shall be serviced in accordance with equipment owner’s PM program.

6.5.5.3 The adjustable choke backup pneumatic/hydraulic control system shall be checked to ensure operation in the event of loss of primary power supply in accordance with equipment owner's PM program.

6.5.5.4 The frequency of the choke drill shall be at initial BOP installation and subsequent BOP testing, at each casing point or in accordance with equipment owner's PM program.

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

6.5.6 In-the-field Control System Accumulator Capacity

6.5.6.1 General

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

6.5.6.1.2 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 friction, hose expansion, control valve interflow as well as heat energy losses. Therefore, the establishment by the manufacturer of the design accumulator capacity provides a safety factor. This safety factor provides 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 provided in Annex C.

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

6.5.6.2 Drawdown Test

6.5.6.2.1 The purpose of the drawdown test is to verify that the accumulator system is able to support the fluid volume and pressure requirements of the BOPs in use, to be capable of securing the well in the event of total loss of power.

6.5.6.2.2 This test shall be performed after the initial nipple-up of the BOPs, after any repairs that required isolation/partial isolation of the system, or every 6 months from previous test, using the following example (see Annex A).

a) Position a properly sized joint of drill pipe or a test mandrel in the BOPs.

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

c) Record the initial accumulator pressure. Manifold and annular regulators shall be set at the manufacturer's recommended operating pressure for the BOP stack.

d) Individually close a maximum of four pipe rams with the smallest operating volumes (except blind or blind shear ram BOPs) and record the closing times. To simulate closure of the blind or blind shear rams, open one set of the pipe rams. Closing times shall meet the response times in 6.3.8.

NOTE Volumes associated with substituting a pipe ram for a BSR may be different, but closing the same ram combination confirms consistent operation.

e) Open the hydraulic operated valve(s) and record the time.

f) Close the (largest volume) annular BOP and record the closing time.

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

NOTE 1 When performing the accumulator drawdown test, wait a minimum of 1 hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test.

NOTE 2 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 minutes after recording the pressure, if the pressure was less than 200 psi (1.38 MPa) above the precharge 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 200 psi (1.38 MPa) above precharge pressure has not been reached after 15 minutes you may have to wait an additional 15 minutes due to ambient temperatures negatively affecting the gas properties. After 30 minutes from the time the final pressure was recorded, if the 200 psi (1.38 MPa) above precharge has not been reached, bleed down the system and verify precharge pressures and volume requirements for the system.

6.5.7 Inspections

6.5.7.1 General

6.5.7.1.1 Inspection and maintenance of the well control equipment shall be performed in accordance with the equipment owner's PM program.

6.5.7.1.2 The equipment owner's PM program shall address inspection (internal/external visual, dimensional, NDE, etc.) and pressure integrity testing.

6.5.7.1.3 Inspections shall be performed every 90 days, after each well, or in accordance with documented equipment owner's reliability data, whichever is greater.

6.5.7.1.4 Certain well operations or conditions (e.g. milling, well control events, bromide use, etc.) will require more frequent inspection and maintenance.

6.5.7.2 Inspection of Flexible Choke and Kill Hoses

6.5.7.2.1 The internal and external inspection programs shall be performed as specified by the equipment owner's PM program in accordance with equipment manufacturer's recommendations.

6.5.7.2.2 For additional guidance see API 7L for flexible line inspection procedures.

6.5.7.3 Periodic Maintenance and Inspection

6.5.7.3.1 Well control equipment system components shall be inspected at least every 5 years in accordance with the equipment owner's PM program. Individual components and subassemblies may be inspected on a staggered schedule. The inspection results shall be verified against the manufacturer's acceptance criteria.

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

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

b) the date new equipment (other than 6.5.7.3.1a), repaired equipment, or remanufactured equipment is installed into the system;

c) the date of last inspection for the component, if preservation and storage records in accordance with 6.5.8.4, are not available.

6.5.7.3.2 As an alternative to a schedule-based inspection program, the inspection frequency may vary from this 5-year interval if the equipment owner collects and analyzes condition-based data (including performance data) to justify a different frequency.

6.5.7.3.3 For schedule and condition based inspection programs, shear ram blades, shear ram blocks, and blade retention bolts shall be inspected annually by visual inspection and surface NDE. The inspection results shall be verified against the manufacturer's acceptance criteria.

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

6.5.7.3.5 Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.

6.5.7.3.6 Documentation of all repairs and remanufacturing shall be maintained in accordance with 6.5.9.

6.5.8 Maintenance

6.5.8.1 Installation, Operation, and Maintenance Manuals

Rig-specific procedures shall be developed for the installation, operation, and maintenance (IOM) of BOP's for the specific well and environmental conditions. The IOM manuals shall be available on the rig for all BOP equipment installed on the rig.

6.5.8.2 Connections

6.5.8.2.1 Fasteners in the load path, both male and female threads, shall be tested using a go, no-go gauge.

6.5.8.2.2 After a pressure seal is broken, the connection shall be established by applying the appropriate torque to the connection studs and/or bolts in accordance with API 6A.

6.5.8.2.3 Manuals or bulletins containing torque specifications shall be available on the rig.

6.5.8.2.4 Torque shall be applied to studs and/or bolts in a criss-cross manner or in accordance with OEM recommendations.

6.5.8.2.5 The appropriate lubricant shall be used with the corresponding torque.

6.5.8.2.6 After the initial pressure test is completed, all bolts shall then be rechecked for proper torque.

6.5.8.2.7 When making up connections, excessive force should not be required to bring the connections into alignment.

6.5.8.2.8 When making up proprietary (non-API) clamp hub connections, the manufacturer's recommended procedure shall be followed.

6.5.8.3 Replacement Assemblies

6.5.8.3.1 Replacement assemblies shall be designed for their intended use in accordance with industry standards. After installation, the affected pressure-containing equipment shall be pressure tested.

6.5.8.3.2 If replacement assemblies are acquired from a non-OEM, the assemblies shall meet or exceed the original equipment specifications and be fully tested, design verified, and supported by traceable documentation in accordance with relevant specifications.

6.5.8.4 Equipment Storage

6.5.8.4.1 Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

6.5.8.4.2 When a BOP, component, or assembly is taken out of service for an extended period of time, it shall be completely washed or steam cleaned, and machined surfaces coated with a corrosion inhibitor.

6.5.8.4.3 For BOPs, the rams or sealing element shall be removed and the internal BOP body/cavities shall be thoroughly washed, inspected, and coated with a corrosion inhibitor in accordance with the equipment owner's and manufacturer's requirements.

6.5.8.4.4 Connections shall be covered and protected.

6.5.8.4.5 The hydraulic operating chambers shall be flushed with a corrosion inhibitor and hydraulic connections plugged.

6.5.8.4.6 The equipment shall be stored in a manner to protect it from environmental damage.

6.5.8.5 Weld Repairs

6.5.8.5.1 All welding of wellbore pressure-containing and/or load-bearing components shall be performed in accordance with one of the following:

a) API 6A;

b) API 16A;

c) manufacturer's standards;

d) other applicable standards in consultation with the OEM.

6.5.8.5.2 All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE MR0175/ISO 15156.

6.5.8.5.3 Verification of compliance shall be established through the implementation of a written WPS and the supporting PQR from the repair facility.

6.5.8.5.4 Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME *BPVC*, Section IX, Article II.

6.5.8.5.5 The base material of the part to be welded shall be identified prior to the creation of any WPS or PQR by the remanufacturer.

6.5.8.6 Poor Boy Degasser/Mud-Gas Separation Systems Inspection and Maintenance

6.5.8.6.1 Equipment owner’s PM program shall include removal of inspection plates and clearing of debris.

6.5.8.6.2 Vent ports and lines shall be inspected to ensure debris or other deficiencies do not impair the operability of the system.

6.5.8.6.3 An inspection program to consider corrosion and erosion shall be performed in accordance with the equipment owner’s PM program.

6.5.8.6.4 Inspect vent lines, in accordance with equipment owner's PM program, to ensure they are adequately braced and vented.

6.5.8.6.5 Where installed, gauges shall be inspected for damage and operation and replaced with a properly sized gauge for the rated pressure of the system.

6.5.8.6.6 Pump water or drilling fluid into the degasser inlet and verify unobstructed.

6.5.8.6.7 If the degasser is equipped with a float to regulate liquid discharge, observe that the float properly regulates liquid discharge.

6.5.8.6.8 If manufactured to the ASME BPVC or equivalent specification, a one-time hydrostatic pressure test shall be performed in accordance with the design codes, when test documentation does not currently exist.

6.5.8.6.9 If weld repairs are made to the poor boy degasser or mud/gas separator, NDE and inspection shall be performed in accordance with Table 2.

6.5.9 Quality Management

6.5.9.1 Planned Maintenance Program

6.5.9.1.1 A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, shall be employed on each rig.

6.5.9.1.2 Electronic and/or hard copy records for maintenance, repairs, and remanufacturing performed for the well control equipment, shall be readily available and preserved at an offsite location until the equipment is permanently removed from the rig or service.

6.5.9.1.3 Electronic and/or hard copy records of remanufactured parts and/or assemblies shall be readily available and preserved at an offsite location, including documentation that shows the components meet or exceed the OEM specifications.

6.5.9.2 Manufacturer’s Product Alerts/Equipment Bulletins

Copies (electronic or paper) of equipment manufacturer's product alerts or equipment bulletins, for the equipment in use on the rig, shall be maintained at the rig site for the well control equipment.

6.5.10 Records and Documentation

6.5.10.1 General

6.5.10.1.1 Electronic and/or hard copies of all applicable standards and specifications relative to the well control equipment shall be readily available.

6.5.10.1.2 The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site.

6.5.10.2 Posted Documentation

6.5.10.2.1 Drawings showing ram space-out and bore of the BOP stack, and a drawing of the choke manifold, showing the pressure rating of the components, shall be posted on the rig floor and maintained up to date (see Figure 8 for an example drawing).

6.5.10.2.2 A piping and instrumentation diagram (P&ID) of the BOP control system shall be maintained on file at the rig.

6.5.10.2.3 Post calculated shear pressures on the rig floor and update in accordance with drilling operations [e.g. drill pipe properties, MASP, maximum expected wellbore shear pressure (MEWSP), leak-off test, mud weights, etc.].

6.5.10.2.4 For tubulars requiring an annular or ram preventer closing pressure different than the normal [e.g. 1500 psi (10.34 MPa)], closing pressure shall be obtained, posted, and the regulator pressure adjusted, prior to placing the tubular in the annular or ram preventer.

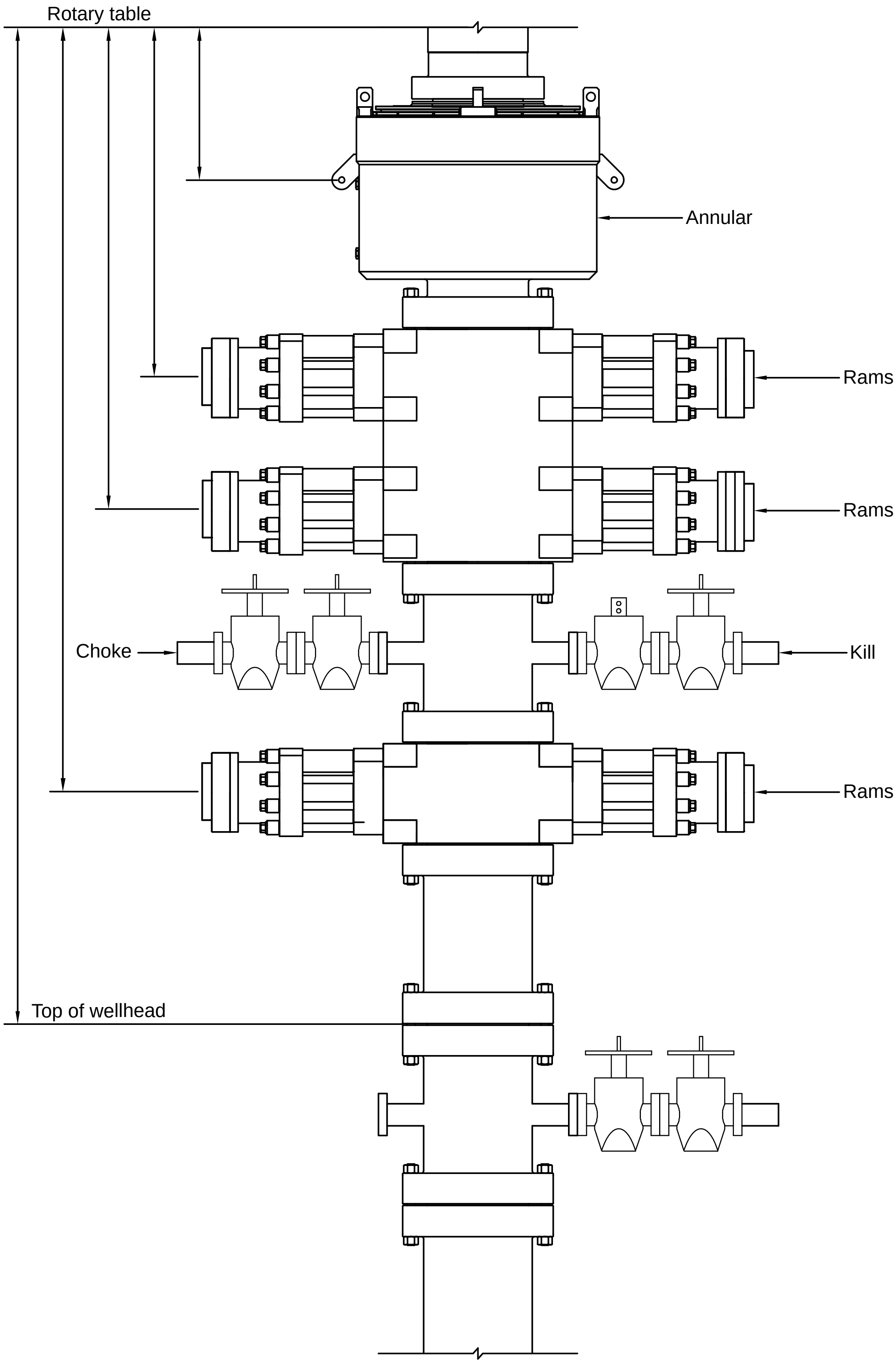

Figure 8—Example Illustration of Surface BOP Ram Space-out

6.5.10.3 Operation and Maintenance Manuals

6.5.10.3.1 Rig manuals, including equipment drawings, specifications, and bills of material, shall be at the rig site to identify the equipment and assist with procuring correct replacement parts.

6.5.10.3.2 Modifications, alterations, or adjustments from the original design or intent of the BOP and control system shall be documented through the use of a MOC system.

6.5.10.4 Equipment Data Book and Certification

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

6.5.10.4.2 Copies of the manufacturer's equipment data book and third-party certification shall be available for review.

6.5.10.4.3 Electronic and/or hard copies of all documentation shall be retained at an offsite location.

6.5.10.5 Maintenance History and Problem Reporting

6.5.10.5.1 A maintenance and repair historical file shall be retained by serial number or unique identification number for each major piece of equipment.

6.5.10.5.2 The maintenance and repair historical file shall follow the equipment when it is transferred.

6.5.10.5.3 Equipment malfunctions or failures shall be reported in writing to the equipment manufacturer in accordance with Annex B.

6.5.10.5.4 The equipment owner shall maintain a log of BOP and control system failures. The log shall provide a description and history of the item that failed along with the corrective action. The failure log shall be limited to items used for wellbore pressure control and the equipment used to function this equipment.

6.5.10.5.5 Details of the BOP equipment, control system, and essential test data shall be maintained from the beginning to the end of the well and considered for use in condition-based analysis.

6.5.10.5.6 Electronic and/or hard copies of all documentation shall also be retained at an offsite location.

6.5.10.6 Test Procedures and Test Reports

6.5.10.6.1 Testing after major modifications or equipment weld repairs shall be performed according to the manufacturer's written procedures.

6.5.10.6.2 Rig specific procedures for installation, removal, operation, and testing of all well control equipment installed shall be available and followed.

6.5.10.6.3 Pressure and function test reports shall be developed, recorded, and retained including preinstallation, initial and all subsequent tests for each well.

6.5.10.6.4 Pressure and function test reports shall be retained for a minimum of 2 years at the rig site, and copies of these documents shall be retained at a designated offsite location.

6.5.10.7 Shearing Pipe and Other Operational Considerations

6.5.10.7.1 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 thorough risk assessment.

6.5.10.7.2 It is important to understand the effects of increasing wellbore pressure and its impact on the capability of shearing the drill pipe with a closed annular preventer. For this reason, it is important to understand the equipment designs, their application/use, and the components run in the wellbore and the BOP/ control system in use.

6.5.10.7.3 When shear rams are installed between the annular and pipe ram, the annular should be opened as soon as possible after closing the pipe ram to remove the well pressure and reduce the closing force/pressure required to shear (see Table 4).

6.5.10.7.4 Close a pipe ram and open the annular as soon as possible to reduce the response time and complexity of the well control operation.

6.5.10.7.5 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. An additional risk assessment should be performed if the shear pressure is higher than 90 % of the maximum operating pressure.

6.5.10.7.6 If shearing pressures approach the restart pressure (10 % threshold) of the accumulator charging pumps, the pump restart pressure should be increased nearer to the maximum operating pressure of the system.

6.5.10.7.7 If the BSR or casing shear ram (CSR) are used to shear pipe during a well control event, the ram block shall be inspected and the BOP tested as soon as operations allow.

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

6.5.10.7.9 Post calculated shear pressures on the rig floor and update in accordance with drilling operations (e.g. drill pipe properties, MASP, MEWSP, leak-off test, mud weights, etc.) for all to view and be aware of those pressures. See Table 4 for an example of shearing calculations.

6.5.10.7.10 If a single ram is incapable of both shearing and sealing, two rams shall be closed; one that is capable of shearing the drill pipe and one that will seal against RWP. Additional functions may be added but shall not interfere with the main purpose of shearing drill pipe and sealing the well.

Table 4—Example Surface MEWSP Calculations Given Well and Equipment-specific Data

Actual or Calculated Shear Value psig (MPa)	**MASP** psig (MPa)	**Shearing Ratio** (SR)	**Control System Operating Pressure** psig (MPa)
2174 (14.99)	5000 (34.47)	14.64	3000 (20.68)

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)

NOTE 1 These equations show relative shear pressures. Accumulator calculations should use absolute pressures.

NOTE 2 These calculations are presented as an example only and are not intended to restrict the use of other methods.

7 Subsea BOP Systems

7.1 Subsea BOP Stack Arrangements

7.1.1 Subsea BOP Stack Pressure Designations

7.1.1.1 Blowout preventer equipment is based on RWPs and designated as 5K, 10K, 15K, 20K, 25K, and 30K as described in Table 5.

Table 5—Subsea BOP Pressure Designations

Pressure Designation	Rated Working Pressure
5K	5,000 psi (34.47 MPa)
10K	10,000 psi (68.95 MPa)
15K	15,000 psi (103.42 MPa)
20K	20,000 psi (137.90 MPa)
25K	25,000 psi (172.37 MPa)
30K	30,000 psi (206.84 MPa)

7.1.1.2 Every installed ram BOP shall have, as a minimum, a RWP equal to the maximum anticipated wellhead pressure (MAWHP) to be encountered.

7.1.2 BOP Stack Classifications

7.1.2.1 The classification or "class" of a BOP stack is the total number of ram and annular preventers in the BOP stack.

7.1.2.2 The quantity of pressure containment sealing components in the vertical wellbore of a BOP stack shall be used to identify the classification or “class” for the BOP system installed. The designation Class 6 represents a combination of a total of six ram and/or annular preventers installed (e.g. two annular and four ram preventers or one annular and five ram preventers, in the case of the Class 6 described).

7.1.2.3 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 identifying two annular preventers installed).

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

NOTE An example of a Class 6 BOP system installed with two annular and four ram type preventers shall be designated as “Class 6-A2-R4.”

7.1.3 Subsea BOP Stack Arrangements

7.1.3.1 General

7.1.3.1.1 The ram and annular preventer positions and outlets on the subsea BOP stack shall provide reliable means to handle potential well control events. Specifically for floating operations, the system shall provide a means to:

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

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

c) strip the drill string;

d) hang-off the drill pipe on a ram BOP and control the wellbore;

e) shear the drill pipe or tubing and seal the wellbore;

f) disconnect the riser from the BOP stack;

g) circulate the well after drill pipe disconnect;

h) circulate across the BOP stack to remove trapped gas.

7.1.3.1.2 Annular preventers having a lower RWP than ram preventers are acceptable.

7.1.3.1.3 The lowermost line connected to the BOP stack shall be identified as the kill line. For BOPs that have lines installed on each side of the outlet below the lowermost well control ram, either may be designated as a choke line or kill line.

7.1.3.1.4 Rig-specific stack identifying nomenclature (choke line, kill line, etc.) shall be part of the drilling program.

7.1.3.1.5 A documented risk assessment shall be performed by the equipment user and the equipment owner for all classes of BOP arrangements to identify ram placements and configurations, and take into account annular and large tubular(s) for well control management.

7.1.3.1.6 Subsea BOP stacks shall be Class 5 or greater and consisting of the following.

a) A minimum of one annular preventer.

b) A minimum two pipe rams (excluding the test rams).

c) A minimum of two sets of shear rams for shearing the drill pipe and tubing in use, of which at least one shall be capable of sealing. For moored rigs, a minimum of one set of BSRs (capable of sealing) for shearing the drill pipe and tubing in use may be used after conducting a risk assessment in accordance with 7.1.3.2.

7.1.3.2 Subsea BOP Stack Risk Assessment for Moored Vessels

7.1.3.2.1 General

The risk assessment process to justify the use of one BSR on subsea BOP stacks shall include the following elements described in 7.1.3.2.2 through 7.1.3.2.4.

7.1.3.2.2 Project Operations

The specific operations of the project shall be assessed; this assessment shall include the following at a minimum:

a) drilling operations, completion operations, plug and abandon or workover operations, well testing, or flowback to the facility;

b) kick scenarios for all operations;

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

d) riser margin and the ability to balance the well with the hydrostatic pressure of seawater;

e) unplanned disconnects;

f) riser failure.

7.1.3.2.3 Rig and Well Control Equipment Capabilities

The capabilities of the rig and the existing well control equipment shall be assessed; this assessment shall include the following at a minimum:

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

b) the pressures required to close/seal the well with pipe rams and shear rams.

7.1.3.2.4 Stationkeeping Systems

The stationkeeping capabilities of the rig shall be assessed; this assessment shall include the following at a minimum:

a) metocean and environmental conditions;

b) mooring components in use;

c) mooring strength analysis;

d) fatigue analysis;

e) marine traffic/shipping lanes.

See API 2INT-MET and API 2SK for more information on metocean criteria and stationkeeping systems respectively.

7.1.4 Storage of Replacement Parts and Assemblies

7.1.4.1 When storing BOP replacement parts and assemblies and related equipment, they should be coated with a protective coating to prevent rust.

7.1.4.2 Elastomer storage shall be in accordance with 4.12.

7.1.4.3 The OEM shall be consulted regarding replacement parts and assemblies.

7.1.4.4 If replacement parts and assemblies are acquired from a non-OEM, the assemblies shall be equivalent or superior to the original equipment and fully tested, design verified, and supported by a MOC and traceable documentation in accordance with relevant specifications.

7.1.5 Drilling Spools

For subsea arrangements, choke and kill lines should be connected to the side outlets of the BOPs (if installed, drilling spools shall meet the requirements of 6.1.6).

7.1.6 Adapter/Spacer Spools

7.1.6.1 Adapter spools are used to connect drill-through equipment with different end connections, nominal size designation and/or pressure ratings to each other. Some typical applications in a subsea stack are

— the connection between the LMRP and the lower stack, and

— between the lowermost ram BOP and the wellhead connector.

7.1.6.2 Spacer spools may be used to allow additional space between preventers to facilitate stripping, hang off, and/or shear operations but can serve other purposes in a stack as well.

7.1.6.3 Adapter/spacer spools for BOP stacks shall meet the following minimum specifications:

— have a minimum vertical bore diameter equal to the internal diameter of the mating equipment;

— have a RWP equal to the lowest rated end connection of the mating equipment.

— have no penetrations capable of exposing the wellbore to the environment.

7.2 Choke Manifolds, Choke Lines, and Kill Lines—Subsea BOP Installations

7.2.1 General

7.2.1.1 Choke and kill equipment shall be in accordance with the edition of API 16C that was in effect at the time of manufacture.

Newer editions should be used for modifications, remanufactured equipment or replacement equipment.

7.2.1.2 The choke manifold assembly for subsea BOP installations has the same purpose as the choke manifold assembly for surface installations: it is used to bleed-off the wellbore pressure at a controlled rate or can stop fluid flow from the wellbore completely, as required.

7.2.1.3 Moonpool choke and kill drape hoses or flexible lines installed that permit entry of gas or hydrocarbons, shall meet the design requirements and performance verification in accordance with API 16C.

7.2.1.4 Figure 9 shows an example choke manifold assembly for a subsea installation for 10,000 psi (34.47 MPa) and greater RWP service.

7.2.2 Subsea BOP Choke Manifolds

7.2.2.1 Manifold equipment subject to well and/or pump pressure (upstream of and including the chokes) shall have a minimum working pressure at least equal to the RWP of the ram BOPs in use. This equipment shall be tested in accordance with provisions of Table 9 and Table 10.

7.2.2.2 Flanged, welded, and hubbed connections (as well as OECs), in accordance with API 6A and API 16A, shall be employed on components subjected to well pressure.

7.2.2.3 Buffer tanks are sometimes installed downstream of the choke assemblies for the purpose of manifolding the bleed lines. When buffer tanks are employed, provision shall be made to isolate a failure or malfunction.

7.2.2.4 The manifold shall be 3 in. (7.62 cm) nominal pipe diameter or larger.

7.2.2.5 All choke manifold valves shall be full bore.

7.2.2.6 A minimum of two remotely operated chokes on 10K and greater manifold systems shall be installed.

7.2.2.7 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.

7.2.2.8 All lines shall be secured to withstand the dynamic effect of fluid flow, pressure, and the impact of drilling solids. Supports and fasteners located at points where piping changes direction shall be capable of restraining pipe deflection. Special attention should be paid to the end sections of the line to prevent line whip and vibration.

7.2.2.9 The minimum nominal ID for lines downstream of the chokes shall be the nominal connection size of the chokes.

7.2.2.10 Lines downstream of the adjustable choke outlet are not required to contain the rated choke manifold pressure (see Table 9 and Table 10 for test pressures).

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

7.2.2.12 Materials used in construction and installation shall be suitable for the expected range of temperature exposure and environmental conditions.

7.2.2.13 The manifold and piping shall be protected from freezing by heating, draining, filling with appropriate fluid, or other appropriate means.

7.2.2.14 Electronic pressure gauges and chart recorder or data acquisition systems shall be used within the manufacturer's specified range.

7.2.2.15 Pressure measurement devices (other than analog gauges) shall be calibrated per OEM procedures annually.

7.2.2.16 Calibrations shall be traceable to a recognized national standard (NIST and ANSI).

7.2.2.17 Pressure gauges shall be installed to easily observe drill pipe and annulus pressures at the station where well control operations are conducted.

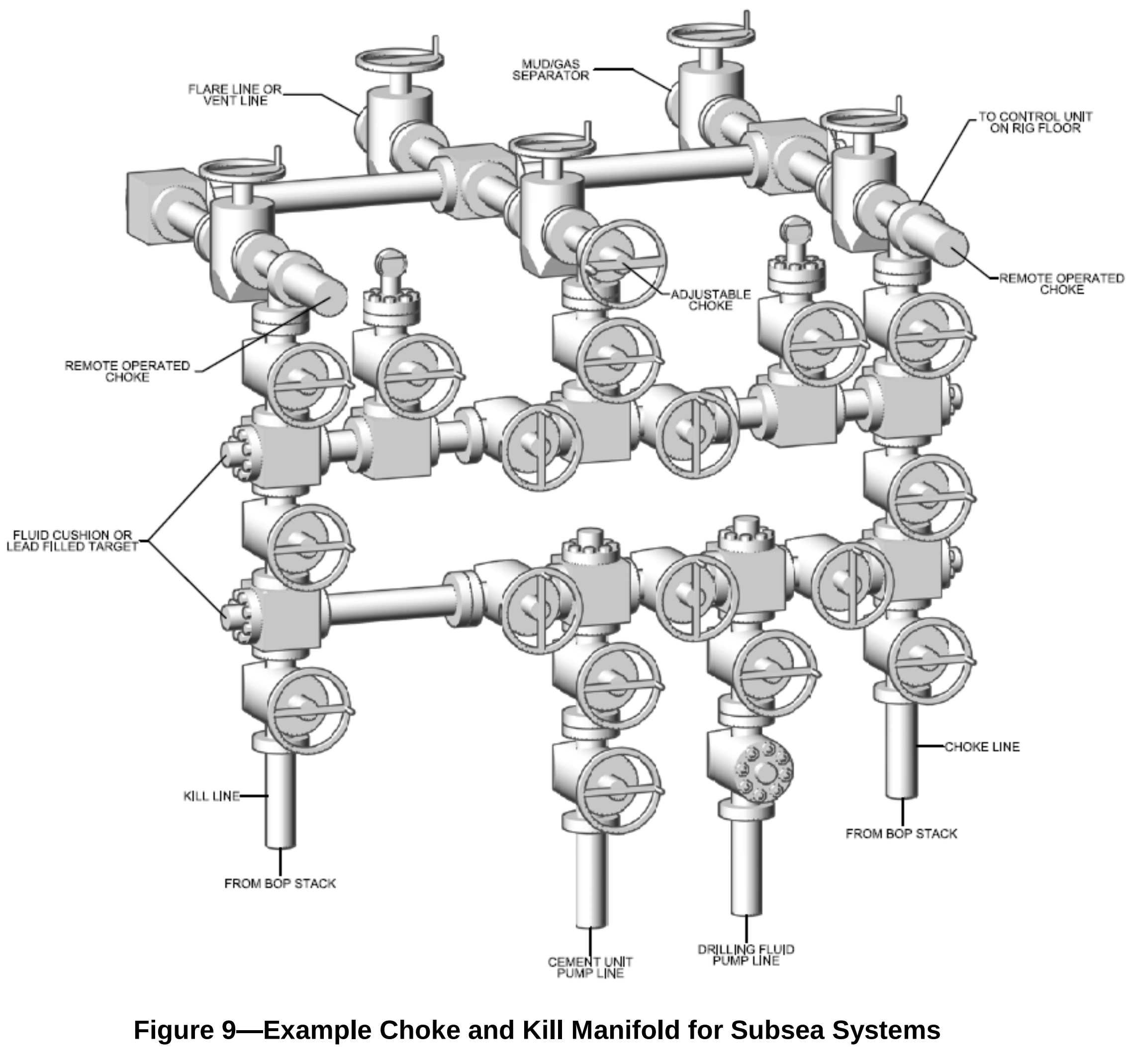

Figure 9—Example Choke and Kill Manifold for Subsea Systems

7.2.2.18 The choke control station shall include all instruments necessary to furnish an overview of the well control operations. This includes the ability to monitor and control such items as standpipe pressure, casing pressure, and monitor pump strokes, etc.

7.2.2.19 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.

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

7.2.2.21 Pressure testing shall be conducted in accordance with applicable provisions of Table 9 and Table 10.

7.2.2.22 Lines downstream of the choke manifold shall be securely anchored and permit flow direction either to a poor boy degasser/mud gas separator (MGS), vent lines, production/test facilities, or emergency storage.

7.2.3 Subsea BOP Choke and Kill Line Installation

7.2.3.1 Choke and Kill Line Bends

7.2.3.1.1 Choke and kill lines should be as straight as possible because erosion at bends is possible during operations.

7.2.3.1.2 Block ells and tees shall be targeted or have fluid cushions installed in the direction of flow or in both directions if bidirectional flow is expected.

If pipe bends with $R/d < 10$ are used without targets or fluid cushions installed in the direction of expected flow or in both directions if bidirectional flow is expected, the equipment owner's PM program shall include an inspection for erosion at the pipe bends at least every two years, where:

R is the radius of pipe bend measured at the centerline in inches (centimeters);

d is the ID of the pipe in inches (centimeters).

7.2.3.1.3 For large radius pipe bends ($R/d \geq 10$), targets or fluid cushions may not be necessary.

7.2.3.1.4 See API 16C for equipment-specific requirements for flexible line assemblies.

7.2.3.1.5 For flexible lines, consult the manufacturer's guidelines on working MBR to ensure proper length determination and safe working configuration.

7.2.3.2 Other Considerations for Choke and Kill Lines

7.2.3.2.1 Choke and kill lines for subsea BOP installations are installed opposite one another on the exterior of the marine riser (see Figure 10). The riser installed choke and kill lines shall be identical in size and pressure rating, and shall be a minimum of 3 in. (7.62 cm) nominal diameter. Either line can serve the choke or kill function.

7.2.3.2.2 If test rams are installed and the kill outlet is below the test ram, the wellbore side of the valves shall be tested by running a test plug:

a) during the subsequent BOP test,

b) in accordance with equipment owner's PM program, or

c) on any tested connections that have been broken (and restricted to that area).

7.2.3.2.3 A minimum of one choke line and one additional kill line connection shall be located above the lowest well control ram BOP.

7.2.3.2.4 Annular bleed valves may be connected to either the choke or kill line. Valves shall be of the same RWP as the choke and/or kill line to which they are attached.

7.2.3.2.5 Selection of choke and kill line connectors joining the LMRP and BOP lines shall consider the ease of reconnecting and disconnect operations and the dependability of sealing elements for those emergency situations where it is necessary to disconnect the LMRP from the BOP stack and then reconnect and test prior to resuming normal operations.

7.2.3.2.6 The LMRP to BOP connector pressure sealing elements shall be inspected, changed as required, and tested before being placed into service. Once in service, testing these connectors is accomplished as part of the BOP testing.

7.2.3.2.7 Pressure ratings of all lines and sealing elements upstream of the chokes shall equal or exceed the RWP of the ram BOPs.

7.2.3.2.8 Subsea choke/kill lines are connected on adjoining riser joints by box-and-pin, stab-in couplings. The box contains an elastomeric radial seal that expands against the smooth, abrasion resistant sealing surface of the pin when the line is pressurized.

7.2.3.2.9 Each BOP outlet connected to the choke or kill line shall have two full-opening valves.

If a spool is used to connect the BOP outlet to the valves:

— the equipment owner's PM program shall include an inspection of the spool for erosion at least every two years, and

— use of the outlet below the lower most ram BOP to take returns should be avoided.

7.2.3.2.10 Location of the choke and kill line openings on the BOP stack depends on the particular configuration of the preventers and the operator’s preferred flexibility for well control operations. Example arrangements are shown in Figure 11. Other arrangements shall meet well control requirements.

7.2.3.2.11 All flexible lines in the choke and kill line system shall have a pressure rating equal to or exceeding the RWP of the ram BOPs. Figure 12 and Figure 13 illustrate example flexible lines for subsea BOP installations.

7.2.3.2.12 Flexible choke and kill line MBR and operating displacement limits shall be determined by the manufacturer’s guidelines. These guidelines shall determine the proper length, proper routing and allow full deflection of the flex joint.

7.2.3.3 Maintenance

7.2.3.3.1 Maintenance of the choke and kill line assemblies shall be performed in accordance with the equipment owner's preventive PM program.

7.2.3.3.2 Frequency of maintenance will depend upon usage. See Table 9 and Table 10 for testing, inspection, and general maintenance of kill manifold systems.

7.3 Discrete Hydraulic Control Systems for Subsea BOP Stacks

7.3.1 General

7.3.1.1 Control systems for subsea BOP stacks shall be in accordance with the edition of API 16D that was in effect at the time of the control system manufacture.

Newer editions should be used for modifications, remanufactured equipment or replacement equipment.

7.3.1.2 The purpose of the BOP control system is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

7.3.1.3 BOP control systems for subsea installations provide hydraulic power fluid as the actuating medium in either a vent-to-sea circuit or a return-to-tank circuit.

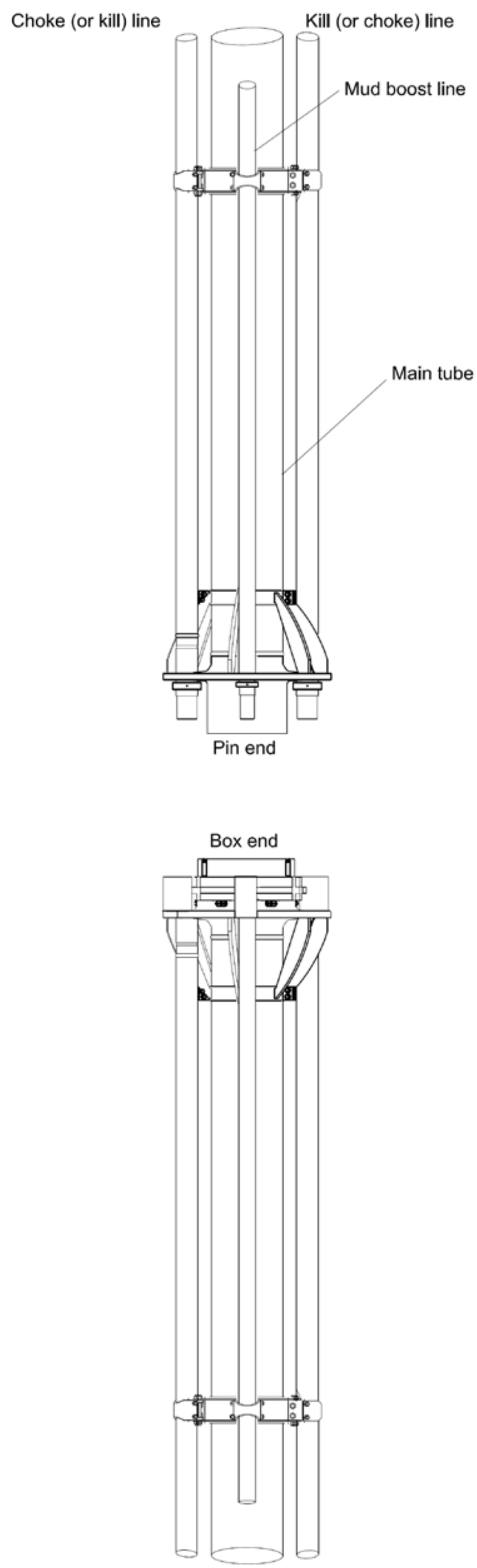

Figure 10—Example Riser-mounted Kill and Choke Lines for Subsea BOP Installations

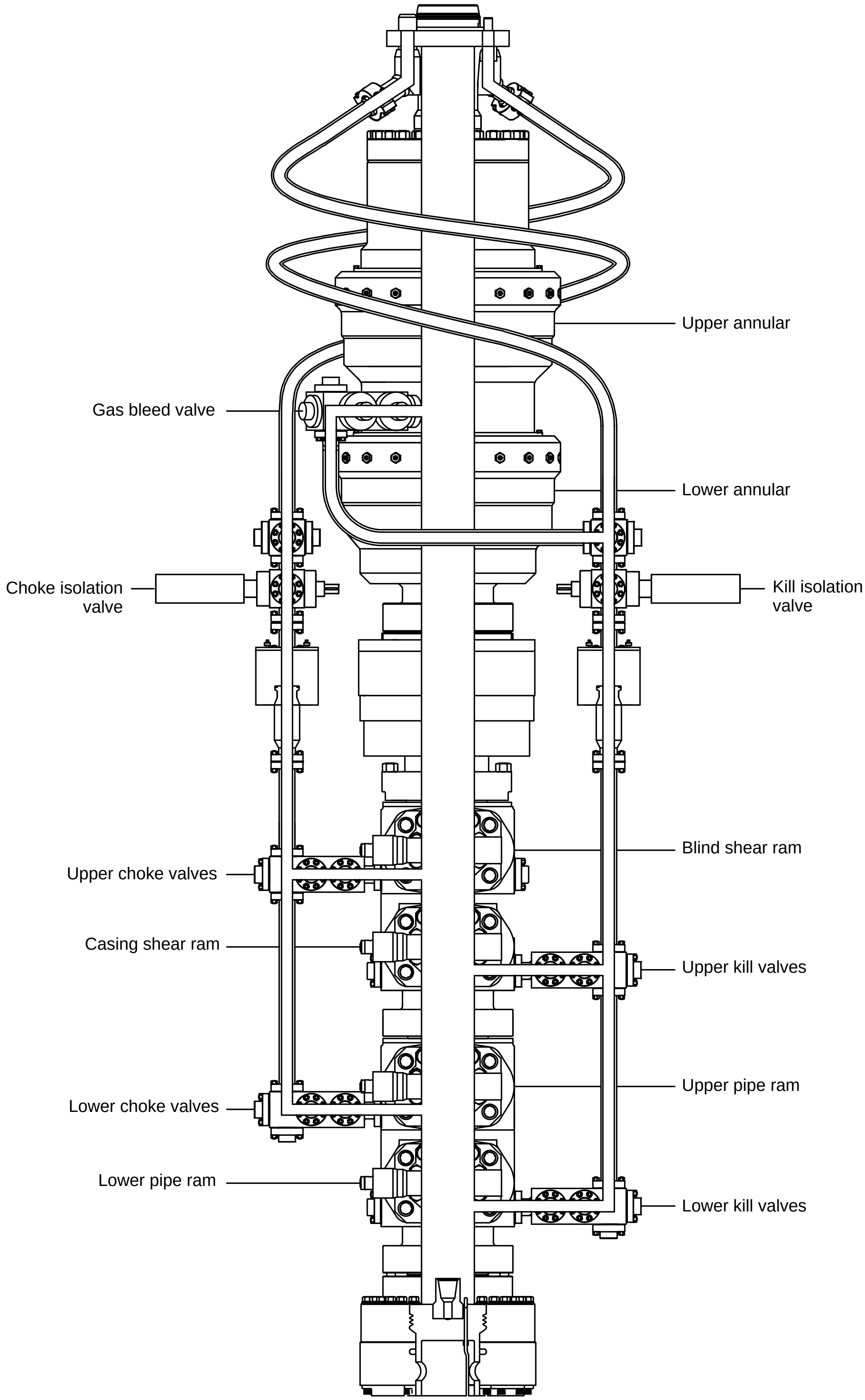

Figure 11—Example Subsea BOP Stack Illustrating Optional Locations for Choke/Kill Lines

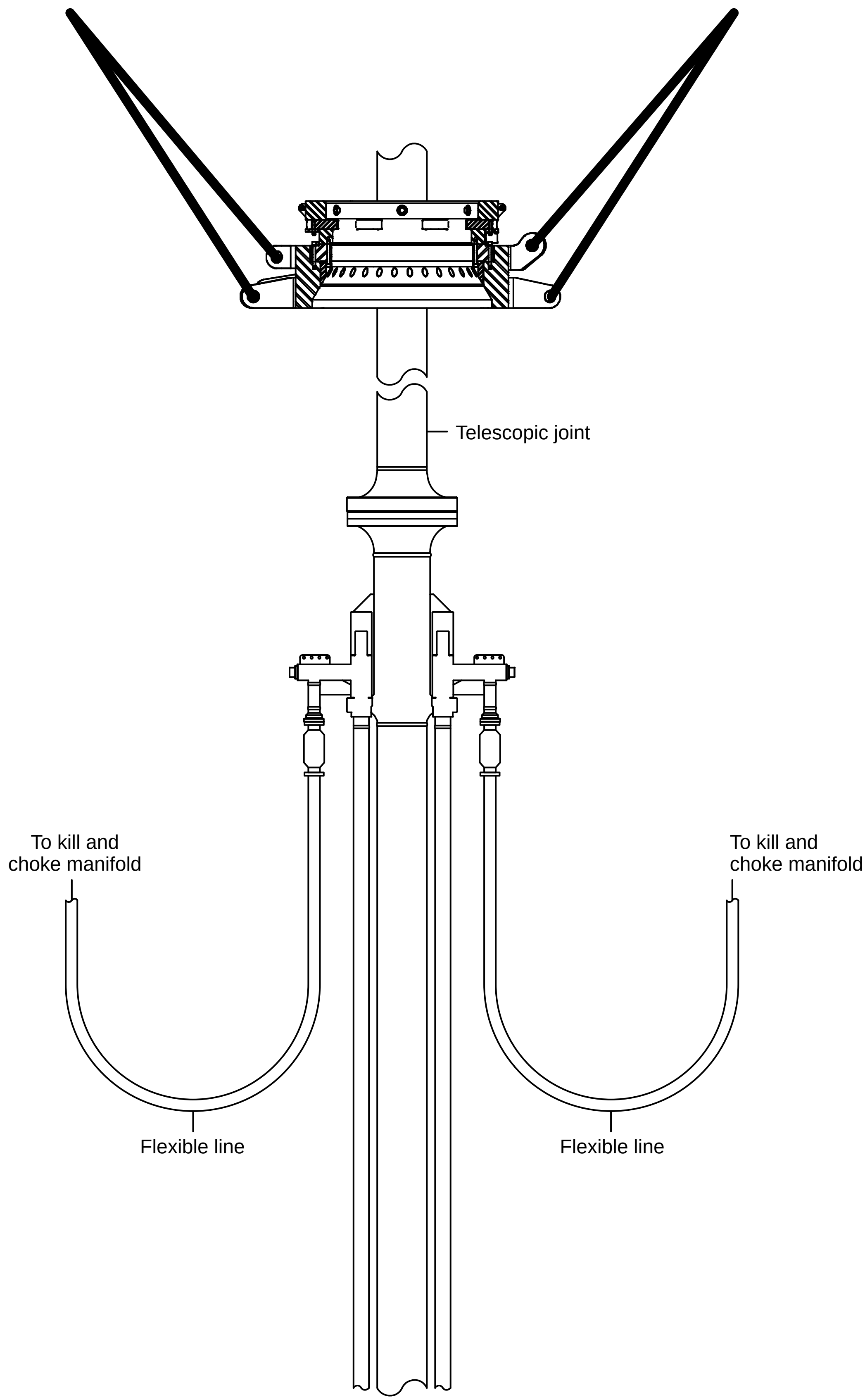

Figure 12—Example Flexible Connection at the Top of Marine Riser for Choke/Kill Lines

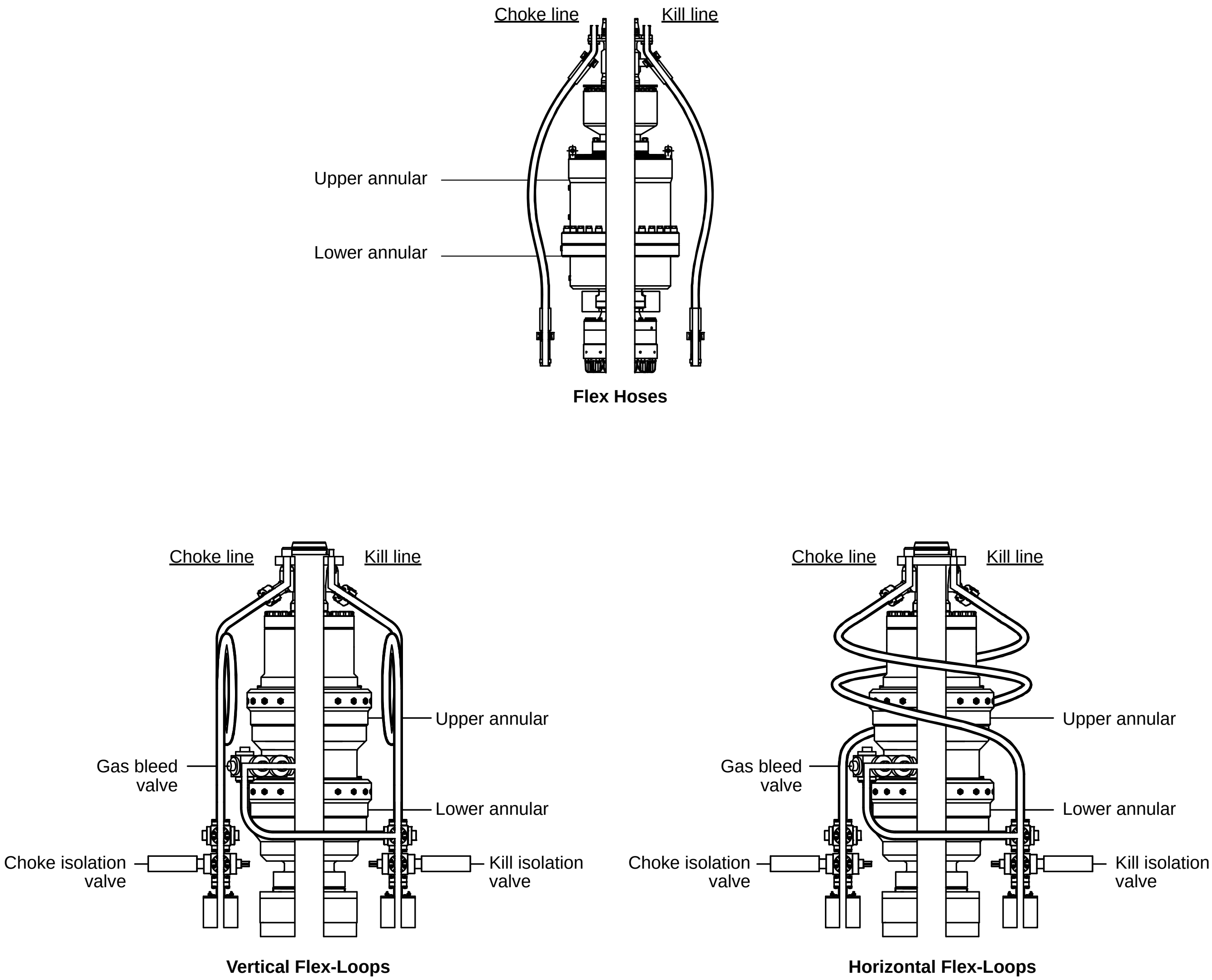

Figure 13—Example Flexible Connection at the Bottom of Marine Riser for Kill/Choke Lines

7.3.1.4 The individual control is provided by an individual pilot line to a valve in the control pod, which is mounted on the LMRP.

7.3.1.5 The minimum required components of the BOP control system shall include the following:

a) control fluid;

b) control fluid reservoir;

c) control fluid mixing system;

d) pump systems;

e) accumulator system;

f) control system valves, fittings, and components;

g) control stations;

h) umbilicals and reels;

i) control pods;

j) emergency systems;

k) secondary control systems.

7.3.2 Control Fluid

7.3.2.1 A suitable control fluid shall be used as the control system operating fluid.

7.3.2.2 Control fluid shall be selected and maintained to meet minimum BOP equipment OEM(s) and fluid supplier properties, and equipment owner requirements.

7.3.2.3 Sufficient volume of glycol shall be added to any closing unit fluid containing water if ambient temperatures below 32 °F (0 °C) are anticipated.

7.3.3 Control Fluid Reservoir

7.3.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

7.3.3.2 To prevent overpressurization, vents shall be inspected and maintained to ensure they are not plugged or capped.

7.3.3.3 Batch mixing fluid is acceptable, or filling the reservoir with hydraulic fluid not requiring mixing is also acceptable.

7.3.3.4 All reservoir instrumentation shall be tested in accordance with equipment owner PM program to ensure they are in proper working order.

7.3.3.5 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner PM program to ensure indication of fluid level in each of the individual reservoirs are in working order.

7.3.4 Control Fluid Mixing System

7.3.4.1 The control fluid mixing system shall be designed for automatic operation.

7.3.4.2 The control fluid mixing system shall be tested to ensure proper functionality of the automatic operating system.

7.3.4.3 The automatic mixing system should be tested to ensure it is manually selectable over the ranges recommended by the manufacturer of the water soluble lubricant additive including proper proportioning of ethylene glycol.

7.3.4.4 A manual override of the automatic mixing system should be tested to ensure proper operation.

7.3.5 Pump Systems

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

7.3.5.2 Each pump system shall have an independent power source. These pump systems shall be connected such that the loss of any one power source does not impair the operation of the other pump systems.

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

7.3.5.4 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.

7.3.5.5 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 system RWP within 30 minutes.

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

7.3.5.7 Each pump system shall provide a discharge pressure at least equivalent to the control system RWP.

7.3.5.8 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system RWP and automatically stop between 97 % to 100 % of the system RWP.

7.3.5.9 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system RWP and automatically stop between 95 % to 100 % of the system RWP.

7.3.5.10 Air pumps shall be capable of charging the accumulators to the system RWP with 75 psi (0.52 MPa) minimum air pressure supply.

7.3.5.11 Each pump system shall be protected from overpressurization by a minimum of two devices:

— 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;

— the second device, such as a certified relief valve, to limit the pump discharge pressure and flow in accordance with API 16D.

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

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

7.3.5.14 The HPU shall meet the classification requirements for the area in which it is installed, and should be outside the rig substructure. See API 500 and API 505 for information on area classification.

7.3.5.15 The HPU shall be located to prevent excessive drainage or flow back from the operating lines to the reservoir.

7.3.6 Accumulator Systems

7.3.6.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions.

7.3.6.2 Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

7.3.6.3 A nonoxidizing (inert) gas with low flammability, such as nitrogen or helium, shall be used for precharging accumulators. Neither atmospheric air or oxygen shall be used.

7.3.6.4 The gas used shall be in accordance with the accumulator design.

7.3.6.5 Subsea accumulators shall have the capability of being completely discharged subsea, prior to recovering the BOP and LMRP to surface.

7.3.7 Main Accumulator System

7.3.7.1 The main accumulator system consists of the surface accumulator system and any stack-mounted accumulators that are part of the main control system (not dedicated accumulators for emergency or secondary systems).

7.3.7.2 A check valve or some other means of preventing control fluid from returning or back flowing to the potable water supply shall be provided. This method of isolation shall be automated to prevent contamination of the main potable water supply.

7.3.8 Dedicated Accumulator Systems

The dedicated accumulators are supplied by the main accumulator system or a dedicated pump/accumulator supply, but shall not be affected if the main supply is depleted or lost.

7.3.9 Accumulator Drawdown Requirements

7.3.9.1 The purpose of the drawdown test is to verify that the accumulator system is able to support the fluid volume and pressure requirements of the BOPs in use, to be capable of securing the well in the event of total loss of power.

7.3.9.2 The main accumulator system shall be capable of performing the accumulator drawdown test with the pumps inoperative (see worksheet in Annex A). The drawdown test shall include closing (from a full open position) and opening (full stroke) at zero (0) wellbore pressure:

— the largest operating volume annular BOP, and

— the four smallest operating volume ram-type BOPs, excluding test rams,

with the remaining system pressure at least 200 psi (1.38 MPa) above the precharge pressure.

NOTE While conducting this test the control system will have limited capability to respond to an emergency (e.g. loss of power). Additional precautions should be taken.

7.3.10 Control System Response Time

7.3.10.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

7.3.10.2 Measurement of closing response time begins when the close function is activated, at any control panel, and ends when the BOP or valve is closed affecting a seal.

7.3.10.3 A BOP can be considered closed when the regulated operating pressure has initially recovered to its nominal setting or other demonstrated means.

7.3.10.4 The following response times shall be met by at least one of the surface/subsea fluid supplies:

a) close each ram BOP in 45 seconds or less;

b) close each annular BOP in 60 seconds or less;

c) unlatch the riser (LMRP) connector in 45 seconds or less;

d) close non-sealing shear rams in 45 seconds or less;

e) response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

7.3.11 Accumulator Precharge

7.3.11.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions. The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

7.3.11.2 The precharge pressure on each accumulator bottle shall be measured in accordance with equipment owner's PM program and adjusted, if necessary.

7.3.11.3 The precharge pressure shall be measured prior to BOP stack deployment and adjusted in accordance with the manufacturer-specified API 16D method (A, B, or C).

7.3.11.4 The manufacturer-supplied control system surface base pressure, adjusted for water depth and operating temperature, shall be used as required. Documentation of the measurement and adjustment shall be retained at the rig site.

7.3.11.5 The calculated precharge pressures, along with documentation supporting nonoptimal precharge pressures (if used), shall be filed with the well-specific data package. See Annex C for examples of accumulator precharge calculations.

7.3.11.6 The design of the BOP, mechanical properties of drill pipe and wellbore pressure may necessitate higher closing pressures for shear operations.

7.3.11.7 The subsea precharge pressure shall not exceed the RWP of the accumulator.

NOTE The precharge pressure for subsea accumulators can exceed the pump pressure for deepwater applications that will affect surface testing.

7.3.12 Accumulators and Pressure Gauge Requirements

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

7.3.12.2 There is an increased risk of damage to the bladder if the precharge pressure is less than 25 % of the system hydraulic pressure.

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

7.3.12.4 The surface accumulator system shall be installed such that the loss of an individual accumulator and/or bank will not result in more than 25 % loss of the surface accumulator system capacity (excludes diverter accumulators).

7.3.12.5 Supply-pressure isolation valves and bleed-down valves shall be provided on each surface accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

7.3.12.6 See 7.6.5.6 for test gauges used for testing and maintenance.

7.3.12.7 All control system analog pressure gauges shall be calibrated to 1 % of full scale at least every 3 years.

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

7.3.12.9 Electronic pressure measurement devices shall be accurate to 1 % of full scale and used within the manufacturer’s specified range

7.3.13 Control System Valves, Fittings, and Components

7.3.13.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a RWP at least equal to the RWP of their respective circuit.

7.3.13.2 Conformity of Piping Systems

7.3.13.2.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

7.3.13.2.2 Pipe, pipe fittings and components shall conform to specifications of ASME B31.3.

7.3.13.2.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

7.3.13.2.4 Welding shall be performed in accordance with a written WPS, written and qualified in accordance with ASME *BPVC*, Section IX.

7.3.13.2.5 All rigid or flexible control lines and hot line supply hoses between the control system and BOP are not required to meet the fire test requirements of API 16D.

NOTE The use of fire retardant hoses can delay or prevent the activation of a deadman system.

7.3.13.2.6 All control system interconnect piping, tubing, hoses, linkages, etc., shall be protected from damage during drilling operations and day-to-day equipment movement.

7.3.13.2.7 The control system shall be equipped with a separate pressure regulator to permit control of the annular preventer(s) operating pressure.

7.3.13.2.8 Surface pressure regulators used for control of BOP shall maintain set regulated pressure in the event of loss of the remote control capability.

7.3.13.2.9 The control system shall be equipped with a pressure regulator to control the operating pressure on the ram BOPs.

7.3.13.2.10 The control system shall be capable of providing high-pressure power fluid to the shear rams, in accordance with manufacturer’s recommendations.

7.3.13.2.11 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.).

7.3.13.2.12 The control system shall be equipped and maintained with measurement devices to indicate

a) accumulator pressure,

b) regulated manifold pressure,

c) regulated annular pressure,

d) air supply pressure,

e) manifold and annular read-backs, and

f) flow metering.

7.3.13.2.13 Isolated accumulator(s) shall be provided for the pilot control system that may be supplied by a separate pump or through a check valve from the main accumulator system. Provision, shall be made to supply hydraulic fluid to the pilot accumulator(s) from the main accumulator system if the pilot pump becomes inoperative.

7.3.14 Control Stations

7.3.14.1 The control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations.

7.3.14.2 All control stations shall meet the classification requirements for the area in which they are installed in accordance with API 500 and API 505.

7.3.14.3 One control station location shall provide easy accessibility for the drill crew.

7.3.14.4 The other control station shall be placed away from the rig floor to provide safe access for functioning the BOPs during an emergency well control event.

7.3.14.5 The following functions shall be protected to avoid unintentional operation:

a) shear rams close;

b) riser connector primary and secondary unlock (LMRP connector unlock);

c) wellhead connector primary and secondary unlock;

d) choke and kill hydraulic connectors and stabs (if installed);

e) pod stab functions (if installed);

f) emergency disconnect sequence (if installed).

7.3.14.6 The control valve handle that operates the blind-shear rams shall be protected to avoid unintentional operation, but still allow full operation from the remote panel without interference.

7.3.15 Umbilicals and Reels

7.3.15.1 Umbilical control hose bundles provide the main supply of power fluid and pilot signals from the surface hydraulic control manifold to the subsea control pods mounted on the BOP stack.

7.3.15.2 The subsea umbilical is run, retrieved, and stored on the hose reel.

7.3.15.3 The umbilicals shall be secured to the pod lines or riser by clamps to prevent abrasive and flexing damage.

7.3.15.4 The outer sheath shall be visually inspected for damage on retrieval.

7.3.15.5 The umbilical shall be tested to MWP of the system and documented on an annual basis.

7.3.15.6 Reterminations, repairs, or splices shall be tested to manufacturers recommended RWP of the hose.

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

7.3.15.8 The end terminations should be inspected at retrieval.

7.3.15.9 Stainless steel fittings should be used for end terminations.

7.3.15.10 There shall be two or more means of surface-to-subsea power fluid supply.

7.3.15.11 Hose reels are used to store, run, and retrieve the umbilical hose bundles that communicate the main hydraulic power fluid supply and command pilot signals to the subsea mounted BOP control pods.

7.3.15.12 The hose reels are equipped with hose reel manifolds having valves, regulators, and gauges for maintaining control through the subsea umbilical of selected functions during running and retrieving of the pod or LMRP and/or the BOP stack.

7.3.15.13 The hose reel shall be equipped with a brake and a mechanical lock that shall be engaged when the hose has been spooled out to desired length.

7.3.15.14 The hose reel drive mechanism shall be fitted with guards to prevent accidental injury to personnel from rotating components.

7.3.15.15 The hose reel controls shall be clearly marked with which reel they control.

7.3.15.16 The hoses and reels should be visually inspected on a daily basis for leakage, or failed valves, hoses, fittings, or gauges.

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

7.3.15.18 Sheaves shall maintain a larger radius than the MBR of the umbilical.

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

7.3.15.20 Sheave mounting supports shall be at least the safe working load of the sheave.

7.3.15.21 The fleet and lead angles should be considered when locating the sheaves,

7.3.16 Subsea Control Pods

7.3.16.1 Subsea stacks shall have fully redundant control pods.

7.3.16.2 Each control pod should contain all necessary valves and regulators to operate the BOP stack and LMRP functions.

7.3.16.3 The control pods may be retrievable or nonretrievable.

7.3.16.4 To isolate the pods from one another, the control lines from each control pod shall be connected to a shuttle valve that is connected to each operable function.

7.3.17 Emergency Disconnect System/Sequence

7.3.17.1 An emergency disconnect sequence (EDS) shall be available on all subsea BOP stacks that are run from a dynamically positioned vessel. A EDS is optional for moored vessels.

7.3.17.2 The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack.

7.3.17.3 The number of sequences, timing, and functions of the EDS are specific to the rig, equipment, and location.

7.3.17.4 There shall be a minimum of two separate locations from which the EDS can be activated (e.g. located in the primary and remote control stations.

7.3.17.5 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.3.18 Autoshear System

7.3.18.1 Autoshear is a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP.

7.3.18.2 Autoshear shall be installed on all subsea BOP stacks.

7.3.18.3 The autoshear system shall be armed while the BOP stack is latched onto a wellhead. A documented MOC shall be required to disarm the system unless covered in equipment owner's standard operating procedures (SOP).

7.3.18.4 The dedicated accumulator system may be used for both the autoshear and deadman systems, as well as for secondary control systems (e.g. ROV and acoustic systems).

7.3.18.5 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.3.18.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.3.19 Deadman System

7.3.19.1 The deadman system is designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and control of both subsea control pods.

7.3.19.2 A deadman system shall be installed on all subsea BOP stacks.

7.3.19.3 The deadman system shall be armed while the BOP stack is latched onto a wellhead. A documented MOC shall be required to disarm the system unless covered in equipment owner's SOP.

7.3.19.4 The dedicated emergency accumulator system may be used for both the autoshear and deadman systems, as well as for secondary control systems (e.g. ROV and acoustic systems).

7.3.19.5 This dedicated emergency accumulator system is supplied from the main control system and shall be maintained (e.g. check valves) if the main supply is lost.

7.3.19.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.3.20 Secondary Control System

7.3.20.1 ROV Intervention

7.3.20.1.1 The BOP stack shall be equipped with ROV intervention equipment that at a minimum allows the operation of the critical functions (each shear ram, one pipe ram, ram locks, and unlatching of the LMRP connector).

7.3.20.1.2 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators (which may be a shared system), or an external hydraulic power source that shall be maintained at the well site. The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions.

7.3.20.1.3 All critical functions shall be fitted with single-port docking receptacles designed in accordance with API 17H.

7.3.20.1.4 If multiple receptacle types are used, a means of positive identification of the receptacle type and function shall be required.

7.3.20.1.5 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.3.20.1.6 All critical functions shall meet the closing time requirements in 7.3.10.4.

7.3.20.2 Acoustic Control Systems

7.3.20.2.1 The acoustic control system is an optional secondary control system designed to operate designated BOP stack and LMRP functions and may be used when the primary control system is inoperable.

7.3.20.2.2 The acoustic control system should be capable of operating critical functions.

7.3.20.2.3 The hydraulic accumulator system may be used for both the acoustic system and emergency control systems.

7.3.20.2.4 This accumulator system can be replenished from the main control supply, but shall be maintained, if the main supply is lost.

7.3.20.2.5 Acoustic accumulators shall be capable of being completely discharged subsea, prior to recovering the BOP to surface.

7.3.20.2.6 Testing the acoustic system shall be in accordance with Table 6, Table 7, and Annex D.

7.3.20.2.7 Response times shall be in accordance with Table 6 and Table 7.

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

7.4.1 General

7.4.1.1 Control systems for subsea BOP stacks shall be in accordance with the edition of API 16D that was in effect at the time of the control system manufacture.

Newer editions should be used for modifications, remanufactured equipment or replacement equipment.

7.4.1.2 The purpose of the BOP control system is to provide a means to individually actuate components in the BOP stack by providing pressurized hydraulic fluid to the selected stack components.

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

7.4.1.4 Subsea multiplex system (MUX) BOP control systems provide hydraulic power fluid as the actuating medium in either a vent-to-sea circuit or a return-to-tank circuit.

7.4.1.5 The minimum required components of the BOP control system shall include the following:

a) control fluid;

b) control fluid reservoir;

c) control fluid mixing system;

d) pump systems;

e) accumulator system;

f) control system valves, fittings, and components;

g) control stations;

h) umbilicals and reels;

i) rigid conduit(s);

j) control pods;

k) emergency systems;

l) secondary control systems.

7.4.2 Control Fluid

7.4.2.1 A suitable control fluid shall be used as the control system operating fluid.

7.4.2.2 Control fluid shall be selected and maintained to meet minimum BOP equipment OEM(s) and fluid supplier properties, and equipment owner requirements.

7.4.2.3 A sufficient volume of glycol shall be added to any closing unit fluid containing water if ambient temperatures below 32 °F (0 °C) are anticipated.

7.4.3 Control Fluid Reservoir

7.4.3.1 Control fluid reservoirs shall be cleaned and flushed of all contaminants before fluid is introduced.

7.4.3.2 To prevent overpressurization, vents shall be inspected and maintained to ensure they are not plugged or capped.

7.4.3.3 Batch mixing fluid is acceptable, or filling the reservoir with hydraulic fluid not requiring mixing is also acceptable.

7.4.3.4 All reservoir instrumentation shall be tested in accordance with equipment owner's PM program to ensure they are in proper working order.

7.4.3.5 Audible and visible alarms shall be tested in accordance with the OEM and equipment owner's PM program to ensure indication of fluid level in each of the individual reservoirs are in working order.

7.4.4 Control Fluid Mixing System

7.4.4.1 The control fluid mixing system (if installed) shall be designed for automatic operation.

7.4.4.2 The control fluid mixing system shall be tested to ensure proper functionality of the automatic operating system.

7.4.4.3 The automatic mixing system (if installed) shall be tested to ensure it is manually selectable over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

7.4.4.4 A manual override of the automatic mixing system (if installed) shall be tested to ensure proper operation.

7.4.5 Pump Systems

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

7.4.5.2 Each pump system shall have an independent power source. These pump systems shall be connected so that the loss of any one power source does not impair the operation of all of the pump systems.

7.4.5.3 At least one pump system shall be available at all times.

7.4.5.4 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.

7.4.5.5 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 system RWP within 30 minutes.

7.4.5.6 The same pump system(s) may be used to provide control fluid to control both the BOP stack and the diverter system. Each pump system shall provide a discharge pressure at least equivalent to the control system RWP

7.4.5.7 The primary pump system shall automatically start before system pressure has decreased to 90 % of the system RWP and automatically stop between 97 % to100 % of the system RWP.

7.4.5.8 The secondary pump system shall automatically start before system pressure has decreased to 85 % of the system RWP and automatically stop between 95 % to 100 % of the system RWP.

7.4.5.9 Air pumps shall be capable of charging the accumulators to the system RWP with 75 psi (0.52 MPa) minimum air pressure supply.

7.4.5.10 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 pump discharge pressure and flow in accordance with API 16D.

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

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

7.4.5.13 The HPU shall meet the classification requirements for the area in which it is installed, and should be outside the rig substructure. See API 500 and API 505 for information on area classification.

7.4.5.14 The HPU shall be located to prevent excessive drainage or flow back from the operating lines to the reservoir.

7.4.6 Accumulator Systems

7.4.6.1 General

7.4.6.1.1 Accumulators are pressure vessels that store pressurized hydraulic fluid to provide the energy necessary for control system functions.

7.4.6.1.2 Accumulators provide the quick response necessary for control system functions and also serve as a backup source of hydraulic power in case of pump failure.

7.4.6.1.3 A nonoxidizing (inert) gas with low flammability, such as nitrogen or helium, shall be used for precharging accumulators. Neither atmospheric air nor oxygen shall be used.

7.4.6.1.3 The gas used shall be in accordance with the accumulator design.

7.4.6.1.5 Subsea accumulators shall have the capability of being completely discharged subsea, prior to recovering the BOP and LMRP to surface.

7.4.6.2 Main Accumulator System

7.4.6.2.1 The main accumulator system consists of the surface accumulator system and LMRP accumulators that are part of the control system (if applicable).

7.4.6.2.2 A check valve or some other means of preventing control fluid from returning or back flowing to the potable water supply shall be provided. This method of isolation shall be automated to prevent contamination of the main potable water supply.

7.4.6.3 Dedicated Accumulator Systems

7.4.6.3.1 The dedicated accumulators are supplied by the main accumulator system or a dedicated pump/accumulator supply, but shall not be affected if the main supply is depleted or lost.

7.4.6.3.2 A dedicated accumulator system shall be provided for the pilot control systems; this may be supplied through a check valve from the main hydraulic supply.

7.4.6.4 Accumulator Drawdown Requirements

7.4.6.4.1 The purpose of the drawdown test is to verify that the accumulator system is able to support the fluid volume and pressure requirements of the BOPs in use, to be capable of securing the well in the event of total loss of power.

7.4.6.4.2 The main accumulator system shall be capable of performing the accumulator drawdown test with the pumps inoperative (see worksheet in Annex A). The drawdown test shall include closing (from a full open position) and opening (full stroke) at zero (0) wellbore pressure:

— the largest operating volume annular BOP, and

— the four smallest operating volume ram-type BOPs, excluding test rams,

with the remaining system pressure at least 200 psi (1.38 MPa) above the precharge pressure.

NOTE While conducting this test the control system will have limited capability to respond to an emergency (e.g. loss of power). Additional precautions should be taken.

7.4.6.5 Control System Response Time

7.4.6.5.1 Response time between activation and complete operation of a function is based on BOP or valve closure and seal off.

7.4.6.5.2 Measurement of closing response time begins when the close function is activated at any control panel and ends when the BOP or valve is closed affecting a seal.

7.4.6.5.3 A BOP can be considered closed when the regulated operating pressure has initially recovered to its nominal setting or other demonstrated means.

7.4.6.5.4 The following response times shall be met by at least one of the surface/subsea fluid supplies:

a) close each ram BOP in 45 seconds or less;

b) close each annular BOP in 60 seconds or less;

c) unlatch the riser (LMRP) connector in 45 seconds or less;

d) close non-sealing shear rams in 45 seconds or less;

e) response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

7.4.6.6 Accumulator Precharge

7.4.6.6.1 The gas pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions. The precharge pressure is the gas pressure in a hydraulically empty accumulator; changing the precharge pressure affects the volume and pressure available from the accumulator once it is hydraulically charged.

7.4.6.6.2 The precharge pressure on each accumulator bottle shall be measured in accordance with equipment owner's PM program and adjusted, if necessary.

7.4.6.6.3 The precharge pressure shall be measured prior to BOP stack deployment and adjusted in accordance with the manufacturer-specified API 16D method (A, B, or C).

7.4.6.6.4 The manufacturer-supplied control system surface base pressure, adjusted for water depth and operating temperature, shall be used as required. Documentation of the measurement and adjustment shall be retained at the rig site.

7.4.6.6.5 The calculated precharge pressures, along with documentation supporting nonoptimal precharge pressures (if used), shall be filed with the well-specific data package. See Annex C for examples of accumulator precharge calculations.

7.4.6.6.6 The design of the BOP, mechanical properties of drill pipe, and wellbore pressure may necessitate higher closing pressures for shear operations.

7.4.6.6.7 The subsea precharge pressure shall not exceed the RWP of the accumulator.

NOTE The precharge pressure for subsea accumulators can exceed the pump pressure for deepwater applications that will affect surface testing.

7.4.7 Accumulators and Pressure Gauge Requirements

7.4.7.1 See 7.6.5.6 for test gauges used for testing and maintenance.

7.4.7.2 No accumulator bottle shall be operated at a pressure greater than its RWP. There is an increased risk of damage to the bladder if the precharge pressure is less than 25 % of the system hydraulic pressure.

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

7.4.7.4 The surface accumulator system shall be installed such that the loss of an individual accumulator and/or bank will not result in more than 25 % loss of the surface accumulator system capacity(excludes diverter accumulators).

7.4.7.5 Supply-pressure isolation valves and bleed-down valves shall be provided on each surface accumulator bank to facilitate checking the precharge pressure or draining the accumulators back to the control fluid reservoir.

7.4.7.6 All control system analog pressure gauges shall be calibrated to 1 % of full scale at least every 3 years.

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

7.4.7.8 Electronic pressure measurement devices shall be accurate to 1 % of full scale and used within the manufacturer's specified range.

7.4.7.9 A pressure gauge for measuring the accumulator precharge pressure shall be available. Those pressure gauges shall be calibrated to 1 % of full scale [e.g. 100 psi (0.69 MPa) full scale on 10K gauge or +/− 50 psi (0.34 MPa)] and used to not less than 25 % or more than 75 % of the full pressure span of the gauge [5000 psi (34.5 MPa) precharge gauge = 1250 psi (8.62 MPa) and 3750 psi (25.9 MPa) pressure measuring device for precharging accumulator].

7.4.8 Control System Valves, Fittings, and Components

7.4.8.1 Pressure Rating

All valves, fittings, and other components, such as pressure switches, transducers, transmitters, etc., shall have a RWP at least equal to the RWP of their respective circuit.

7.4.8.2 Conformity of Piping Systems

7.4.8.2.1 All piping components and all threaded pipe connections installed on the BOP control system shall conform to the design and tolerance specifications as specified in ASME B1.20.1.

7.4.8.2.2 Pipe, pipe fittings and components shall conform to specifications of ASME B31.3.

7.4.8.2.3 If weld fittings are used, the welder shall be certified for the applicable procedure required.

7.4.8.2.4 Welding shall be performed in accordance with a written WPS, written and qualified in accordance with ASME *BPVC*, Section IX.

7.4.8.2.5 All rigid or flexible control lines, MUX cables, and hot line supply hoses between the control system and BOP are not required to meet the fire test requirements of API 16D.

NOTE The use of fire retardant hoses can delay or prevent the activation of a deadman system.

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

7.4.8.2.7 The control system shall be equipped to allow isolation of the pumps and the accumulators from the control circuits, thus allowing maintenance and repair work.

7.4.8.2.8 The control system shall be equipped with a separate pressure regulator to control the operating pressure on annular preventer(s).

7.4.8.2.9 Pressure regulators used for control of BOP systems shall maintain set regulated pressure in the event of loss of the remote control capability.

7.4.8.2.10 The control system shall be equipped with a pressure regulator to control the operating pressure on the ram BOPs.

7.4.8.2.11 The control system shall be capable of providing high-pressure power fluid to the shear rams in accordance with manufacturer’s recommendations.

7.4.8.2.12 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.).

7.4.8.2.13 The control system shall be equipped and maintained with measurement devices to indicate

a) surface accumulator pressure,

b) LMRP accumulator pressure (if applicable),

c) stack accumulator pressure,

d) pod supply pressure,

e) pilot supply pressure,

f) all control pod regulator pressures, and

g) flow metering.

7.4.9 Control Stations

7.4.9.1 Control systems shall clearly identify each function and the function position (e.g. open, closed, etc.).

7.4.9.2 The following functions shall be protected to avoid unintentional operation:

a) shear rams close;

b) riser connector primary and secondary unlock (LMRP connector unlock);

c) wellhead connector primary and secondary unlock;

d) choke and kill hydraulic connector unlock and stabs retract (if installed);

e) pod stab functions (if installed);

f) emergency disconnect sequence (if installed).

7.4.9.3 The control system shall have the capability to control all of the BOP stack functions, including pressure regulation and monitoring of all system pressures from at least two separate locations.

7.4.9.4 All control stations shall meet the classification requirements for the area in which they are installed in accordance with API 500 and API 505.

7.4.9.5 One control station location shall provide easy accessibility for the drill crew.

7.4.9.6 The other control station shall be placed away from the rig floor to provide safe access for functioning the BOPs during an emergency well control event.

7.4.9.7 The central control unit shall be supplied with electrical power from an uninterruptible power supply.

7.4.9.8 All control stations for BOP functions shall be on an uninterruptible power supply.

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

7.4.9.10 The control unit shall maintain function status memory in the event of power and/or communications interruption.

7.4.9.11 Upon restoration of power, the system shall display the status of all functions as they were prior to the loss of power or communications.

7.4.10 Data Acquisition and Remote Monitoring

7.4.10.1 Data shall be captured or logged during the course of well drilling operations.

7.4.10.2 Data captured shall include as a minimum the time and date stamp, solenoid functions energized, regulator and read-back pressures, and subsea accumulator pressures.

7.4.10.3 Data shall be retained in a manner that is easily retrievable (e.g. transmission to shore monitoring, backup).

7.4.11 Umbilicals and Reels

7.4.11.1 There shall be two or more means of surface-to-subsea power fluid supply. The rigid conduit(s) are attached to the riser and provide the primary hydraulic supply to the subsea control pods.

7.4.11.2 The hotline hose supplies power fluid from the surface to the subsea control pods mounted on the LMRP. The hotline is run, retrieved, and stored on the hose reel.

7.4.11.3 The hotline(s) and MUX cable(s) shall be secured to the riser by clamps to prevent abrasion and flexing damage. The outer sheath should be visually inspected for damage on retrieval.

7.4.11.4 The hot line(s) shall be tested to MWP of the system and documented on an annual basis.

7.4.11.5 Reterminations, repairs or splices shall be tested to manufacturers recommended RWP of the hose.

7.4.11.6 The MUX electrical cable supplies power and communications for control of the subsea control pods. The MUX cable is run, retrieved, and stored on a cable reel.

7.4.11.7 The electrical conductors and electrical insulation shall not be used as load bearing components in the cable assembly.

7.4.11.8 All underwater electrical umbilical cable terminations shall be sealed to prevent water migration into the cable in the event of connector failure or leakage and to prevent water migration from the cable into the subsea connector termination in the event of water intrusion into the cable.

7.4.11.9 Individual connector terminations shall be physically isolated so that seawater intrusion does not cause electrical shorting.

7.4.11.10 The hose/MUX reel shall be equipped with a brake and a mechanical lock that shall be engaged when the hose/MUX cable has been spooled out to desired length.

7.4.11.11 The hose/MUX reel drive mechanism shall be fitted with guards to prevent accidental injury to personnel from rotating components.

7.4.11.12 The hose/MUX reel controls shall be clearly marked with which reel they control.

7.4.11.13 The hoses, cables, and reels should be visually inspected on a daily basis for damage and proper operation.

7.4.11.14 Hose/cable sheaves should facilitate running and retrieving the hotline from the hose reel through the moonpool and support the moonpool loop that is deployed to compensate for vessel heave.

7.4.11.15 Sheaves shall maintain a larger radius than the MBR of the umbilical.

7.4.11.16 Hose/cable sheaves shall be mounted to permit three-axis freedom of movement and prohibit damage to the umbilical in normal ranges of anticipated movement.

7.4.11.17 Sheave mounting supports shall be at least the SWL of the sheave.

7.4.11.18 Consider fleet and lead angles when locating the sheaves.

7.4.12 Subsea Control Pods

7.4.12.1 There shall be fully redundant control pods on a subsea stack.

7.4.12.2 Each control pod should contain all necessary valves and regulators to operate the BOP stack and LMRP functions.

7.4.12.3 The control pods may be retrievable or nonretrievable.

7.4.12.4 The control lines from each control pod shall be connected to a shuttle valve that is connected to the function to be operated.

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

7.4.13 Emergency Disconnect System/Sequence

7.4.13.1 An EDS shall be available on all subsea BOP stacks that are run from a dynamically position vessel. A EDS is optional for moored vessels.

7.4.13.2 The EDS is a programmed sequence of events that operates the functions to leave the stack and controls in a desired state and disconnect the LMRP from the lower stack.

7.4.13.3 The number of sequences, timing, and functions of the EDS are specific to the rig, equipment, and location.

7.4.13.4 There shall be a minimum of two separate locations from which the EDS can be activated (e.g. located in the primary and remote control stations).

7.4.13.5 Response times shall be in accordance with Table 6 and Table 7.

7.4.14 Autoshear System

7.4.14.1 Autoshear is a safety system that is designed to automatically shut in the wellbore in the event of an unintended disconnect of the LMRP.

7.4.14.2 Autoshear shall be installed on all subsea BOP stacks.

7.4.14.3 The Autoshear system shall be armed while the BOP stack is latched onto a wellhead. A documented MOC shall be required to disarm the system unless covered in equipment owner's SOP.

7.4.14.4 The dedicated emergency accumulator system may be used for both the autoshear and deadman systems, as well as for secondary control systems.

7.4.14.5 This dedicated emergency accumulator system is supplied from the main control system or a dedicated pump/accumulator supply, but shall be maintained (e.g. check valves) if the main supply is lost.

7.4.14.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.4.15 Deadman System

7.4.15.1 The deadman system is designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and control of both subsea control pods.

7.4.15.2 A deadman system shall be installed on all subsea BOP stacks.

7.4.15.3 The deadman system shall be armed while the BOP stack is latched onto a wellhead. A documented MOC shall be required to disarm the system unless covered in equipment owner's SOP.

7.4.15.4 The dedicated emergency accumulator system may be used for both the Autoshear and Deadman systems, as well as for secondary control systems (e.g. ROV or acoustic systems).

7.4.15.5 This dedicated emergency accumulator system is supplied from the main control system or a dedicated pump/accumulator supply, but shall be maintained (e.g. check valves) if the main supply is lost.

7.4.15.6 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.4.16 Secondary Control Systems

7.4.16.1 ROV Intervention

7.4.16.1.1 The BOP stack shall be equipped with ROV intervention equipment that at a minimum allows the operation of the critical functions (each shear ram, one pipe ram, ram locks, and unlatching of the LMRP connector).

7.4.16.1.2 Hydraulic fluid can be supplied by the ROV, stack mounted accumulators (which may be a shared system) or an external hydraulic power source that shall be maintained at the well site. The source of hydraulic fluid shall have necessary pressure and flow rate to operate these functions.

7.4.16.1.3 All critical functions shall be fitted with single-port docking receptacles designed in accordance with API 17H.

7.4.16.1.4 If multiple receptacle types are used, a means of positive identification of the receptacle type and function shall be required .

7.4.16.1.5 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.4.16.1.6 All critical functions shall meet the closing time requirements in 7.4.6.5.4.

7.4.16.2 Acoustic Control System

7.4.16.2.1 The acoustic control system is an optional secondary control system designed to operate designated BOP stack and LMRP functions and may be used when the primary control system is inoperable.

7.4.16.2.2 The acoustic control system should be capable of operating critical functions.

7.4.16.2.3 The hydraulic accumulator system may be used for both the acoustic system and emergency control systems.

7.4.16.2.4 This accumulator system is supplied from the main control system and shall be maintained (e.g. check valves) if the main supply is lost.

7.4.16.2.5 Acoustic accumulators shall be capable of being completely discharged subsea, prior to recovering the BOP to surface.

7.4.16.2.6 Testing the acoustic system shall be in accordance with Table 6, Table 7, and Annex D.

7.4.16.2.7 Frequency of testing and acceptance criteria shall be in accordance with Table 6 and Table 7.

7.5 Auxiliary Equipment for Subsea BOP Stacks

7.5.1 Kelly Valves

7.5.1.1 The kelly cock is installed between the swivel and the kelly.

7.5.1.2 A lower kelly valve is installed immediately below the kelly.

7.5.1.3 A minimum of two kelly valves shall be required, with the bottom valve being capable of use for stripping operations. The size of the valve and the hole/casing in use for stripping operations shall be considered.

NOTE 1 This valve can be closed under pressure to remove the kelly and can be stripped into the hole if a closed IBOP valve is installed above it.

NOTE 2 Some lower kelly valve models are not designed to withstand external pressure encountered in stripping operations.

7.5.2 Drill Pipe Safety Valve

7.5.2.1 A drill pipe safety valve shall be readily available (i.e. stored in open position with wrench accessible) on the rig floor at all times.

7.5.2.2 This valve(s) and crossover sub(s) shall be equipped to screw into any drill string member in use.

7.5.2.3 The outside diameter of the drill pipe safety valve shall be suitable for running into the hole.

7.5.3 Inside Blowout Preventer

7.5.3.1 An inside BOP, drill pipe float valve, or drop-in check valve shall be available for use when stripping the drill string into or out of the hole.

7.5.3.2 The valve(s), sub(s), or profile nipple shall be equipped to screw into any drill string member in use. Crossovers may be used.

7.5.4 Field Testing

The kelly valves, drill pipe safety valve, and inside BOP shall be tested in accordance with Table 9 and Table 10.

7.5.5 Drill String Float Valve

7.5.5.1 A float valve is placed in the drill string to prevent upward flow of fluid or gas inside the drill string. The float valve is a special type of backpressure or check valve. A float valve in good working order will prohibit backflow through the drill string and allow for safe installation of the safety valves.

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

a) The flapper-type float valve offers the advantage of having an opening through the valve that is approximately the same ID as that of the tool joint. This valve will permit the passage of balls, or go-devils, which may be required for operation of tools inside the drill string below the float valve.

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

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

7.5.6 Trip Tank

7.5.6.1 A trip tank shall be installed and used on all wells.

7.5.6.2 A trip tank is a low-volume, 100 barrels (15.9 m^3) or less, calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well.

7.5.6.3 A trip tank may be of any shape provided the capability exists for reading the volume contained in the tank at any liquid level.

7.5.6.4 The trip tank volume readout may be direct or remote, preferably both.

7.5.6.5 The size and configuration of the tank should be such that volume changes approximately one-half barrel can be easily detected by the readout arrangement.

7.5.6.6 Tanks containing two compartments with monitoring arrangements in each compartment are preferred as this facilitates removing or adding drilling fluid without interrupting rig operations.

7.5.6.7 Other uses of the trip tank include measuring drilling fluid or water volume into the annulus when returns are lost, monitoring the hole while logging or following a cement job, calibrating drilling fluid pumps, etc.

7.5.6.8 The trip tank is also used to measure the volume of drilling fluid bled from or pumped into the well as pipe is stripped into or out of the well.

7.5.7 Pit Volume Measuring and Recording Devices

7.5.7.1 Pit volume measuring systems, complete with audible and visual alarms, shall be installed. These systems transmit a signal from sensors in the drilling fluid pits to instrumentation on the rig floor. These are valuable in detecting fluid gains or losses.

7.5.7.2 Audible and visual alarms shall be active during well operations.

7.5.7.3 A pit volume totalizer system shall be installed and used on all rigs.

7.5.8 Flow Rate Sensor

7.5.8.1 A flow rate sensor, complete with audible and visual alarms, shall be mounted in the flow line to provide for early detection of formation fluid entering the wellbore or a loss of returns.

7.5.8.2 Audible and visual alarms shall be active during well operations.

7.5.9 Poor Boy Degasser and Mud/Gas Separator

7.5.9.1 There are two basic types of mud/gas separation systems in use in the industry, poor boy degasser and the mud/gas separator.

7.5.9.2 The most common system is the atmospheric poor boy degasser (or gas buster) that separates gas from the drilling fluid that is gas cut and vents the gas away from the rig.

7.5.9.3 The mud/gas separator is designed such that it can be operated at a moderate backpressure, less than 100 psi (0.69 MPa) or at the gas vent line pressure (atmospheric) plus line friction pressure drop

7.5.9.4 There are advantages and disadvantages to either the atmospheric or pressurized systems. The following are common to both systems:

a) a bypass line to flare/vent/overboard shall be provided in case of a malfunction or in the event the capacity of the system is exceeded;

b) precautions shall be taken to prevent erosion at the point the drilling fluid and gas flow impinges on the wall of the vessel;

c) provisions shall be made for easy clean out of the vessels and lines in the event of plugging;

d) neither system is recommended for well production-type testing operations.

7.5.9.5 The dimensions of the system are critical in that they define the volume of gas and fluid that the system can effectively handle.

7.5.10 Mechanical Type Degasser

7.5.10.1 A mechanical type degasser may be used to remove entrained gas bubbles in the drilling fluid that are too small to be removed by the poor boy separator.

7.5.10.2 Most mechanical type degassers make use of some degree of vacuum to assist in removing this entrained gas.

7.5.10.3 The drilling fluid inlet line to the mechanical type degasser should be placed close to the drilling fluid discharge line from the poor boy degasser to reduce the possibility of gas breaking out of the drilling fluid in the pit.

7.5.11 Flare/Vent Lines

7.5.11.1 All flare/vent lines shall be as long as practical with provisions for flaring/venting during varying wind directions.

7.5.11.2 Flare/vent lines shall be as straight as possible and should be securely anchored.

7.5.11.3 For H_2S operations, the flare/vent line shall be equipped with a remotely operated igniter to flare the gas.

7.5.12 Standpipe Choke

7.5.12.1 If installed, an adjustable choke mounted on the rig standpipe can be used to bleed pressure off the drill pipe under certain conditions, reduce the shock when breaking circulation in wells where loss of circulation is a problem, and bleed-off pressure between BOPS during stripping operations.

7.5.12.2 An adjustable choke on the standpipe manifold may also prevent high-pressure fluid from eroding the valve seals, when bleeding down pressure from the drill string. See Figure 7 for an example standpipe choke installation.

7.5.13 Top Drive Equipment

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

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

a) once the top drive's manual valve is installed, closed, and the top drive disconnected, a crossover may be required to install an inside BOP on top of the manual valve;

b) most top drive manual valves cannot be stripped into 7 $^5/_8$ in. (19.37 cm) or smaller casing;

c) once the top drive's manual valve is disconnected from the top drive, another valve and crossover may be required.

7.5.14 Guide Frames

7.5.14.1 The BOP guide frame, a four-post structure attached to the BOP assembly, is a means for guiding the complete BOP/LMRP assembly's primary alignment onto the permanent guide base (see API 17D).

7.5.14.2 The upper section of the guide structure acts as primary guidance for the LMRP.

7.5.14.3 The guide structure also acts as the structural mounting for the various components of the remote control system and the choke/kill connectors or stab subs.

7.5.14.4 The guide structure should have sufficient strength to protect the BOP stack from damage during handling and landing operations.

7.5.15 Slope Indicator

A slope indicator (or bulls eye) is used to measure the angular deflection of components to which it is attached.

Slope indicators should be installed on the BOP guide frame, LMRP guide frame, and first joint of riser above the lower ball/flex joint.

7.5.16 Pin Connector/Hydraulic Latch

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

7.5.17 Mud Booster Line

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

7.5.18 Hydraulic Supply Line (Hard/Rigid Conduit)

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

7.5.19 Riser Tensioning Support Ring

7.5.19.1 A riser tensioning support ring is attached (integrally or remotely) to the telescopic joint outer barrel to allow tensioning of the riser. The tensioning ring is the mechanical link between the riser and the tensioner cables on the rig. The riser tensioners allow relative movement of the drilling vessel with respect to the stationary riser.

7.5.19.2 The riser support ring shall have protection from unintended release when hung-off under the rotary.

7.6 Maintenance and Testing—Subsea BOP Systems

7.6.1 Purpose

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

a) that specific functions are operationally ready,

b) the pressure integrity of the installed equipment, and

c) the control system and BOP compatibility.

7.6.2 Types of Tests

7.6.2.1 General

7.6.2.1.1 Test programs incorporate visual inspections, function and pressure tests, maintenance practices, and drills.

7.6.2.1.2 A visual inspection shall be performed in accordance with equipment owner's PM program. Operability and integrity can be confirmed by function and pressure testing.

7.6.2.1.3 Site-specific procedures for testing of well control equipment shall be incorporated into acceptance tests, predeployment, installation and subsequent tests, drills, periodic operating tests, maintenance practices, and drilling and/or completion operations.

7.6.2.1.4 Manufacturer operating and maintenance documents, equipment owner PM programs, and operating experiences shall be incorporated into the site-specific procedures.

7.6.2.2 Inspection Methods

7.6.2.2.1 Inspection methods may include, but are not limited to, visual, dimensional, audible, hardness, functional, pressure tests, and electrical testing. Inspection practices and procedures vary and are outside the scope of this document.

7.6.2.2.2 Inspections of all well control assemblies shall be performed in accordance with the equipment owner's PM program for wear, erosion, plugging, or other damages.

7.6.2.3 Function Test

Function testing may or may not include pressure testing.

7.6.2.4 Pressure Test

Pressure test programs for the subsea wellhead and casing shall be prescribed by the equipment user on an individual well basis.

7.6.2.5 Hydraulic Chamber Test

A hydraulic chamber test shall be included in the equipment owner's PM program for items such as:

— BOP operator cylinders and bonnet assemblies;

— hydraulic valve actuators;

— hydraulic connectors, etc.

7.6.3 Crew Drills

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

7.6.4 Crew Competency

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

7.6.5 Test Criteria

7.6.5.1 Function Tests

7.6.5.1.1 All well control components (excluding hydraulic connectors and shear rams) of the BOP stack shall be function tested to verify the component's intended operations at least once every seven days or as operations allow. Pressure tests qualify as function tests. Casing shear and blind shear rams shall be function tested at least once every 21 days.

7.6.5.1.2 Prior to deployment, all control stations and both pods shall be function tested. The operability of individual control stations shall be confirmed.

7.6.5.1.3 Subsequent function tests shall be performed from one BOP control station and one pod weekly. These tests shall rotate through both pods and all control panels where all BOP functions are included. All possible redundant control possibilities are not required every seven days. A function test schedule shall be developed for rotating control stations (excluding remote panels referenced in 7.6.5.1.4) and pods on a weekly rotation.

7.6.5.1.4 If installed, remote panels where all BOP functions are not included (e.g. lifeboat panels, etc.) shall be function tested in accordance with the equipment owner's procedures.

7.6.5.1.5 All ROV function testing shall be performed in accordance with Table 6 and Table 7.

7.6.5.1.6 Actuation times (and volumes, if applicable) shall be recorded in a database for evaluating trends (see sample worksheets in Annex A).

7.6.5.1.7 Release or latching type components of subsea well control systems (choke, kill, riser, wellhead connectors, etc.) and emergency or secondary systems shall be function tested prior to deployment or as defined in equipment owner's PM program.

Table 6—Surface Testing of Secondary, Emergency, and Other Systems

System Type	Secondary Systems Test		Acceptance Criteria
	Components Function Tested	Frequency	
Acoustic	All assigned functions.	Prior to deployment; all assigned components respond.	
	To secure the well.	Prior to deployment.	In 90 seconds or less [c].
ROV—critical functions (blind shear rams close, one pipe ram close, and LMRP unlock/unlatch)	All ROV critical functions.	Prior to deployment.	Ram BOPs in 45 seconds or less, connector(s) in 45 seconds or less [c].
ROV – Non-sealing shear rams	Non-sealing shear rams	Prior to deployment	45 seconds or less
	Emergency Systems Test		
Deadman (or equivalent) circuit test [a d]	All assigned components.	Prior to deployment; all assigned components respond. Tested by removing electric power and hydraulic supply.	
	Components to secure the well.	Prior to deployment.	In 90 seconds or less [c].
Autoshear (or equivalent) circuit test [a d]	All assigned components.	Prior to deployment; all assigned components respond.	
	To secure the well.	Prior to deployment. Tested by activation of trigger, where applicable.	In 90 seconds or less [c].
Emergency disconnect sequence [b]	All assigned components.	Prior to deployment.	In 90 seconds or less [c].

[a] Securing the well means closing rams, valves, and locks and does not include disconnects or other functions that may subsequently be employed after the well has been secured.

[b] EDS not required on moored vessels.

[c] Minimal time requirement to secure the wellbore, does not include functions after the well is secured.

[d] Power fluid may be supplied from surface accumulators or an alternative source.

7.6.5.1.8 A riser recoil test shall be performed in accordance with Table 8 and equipment owner PM program.

7.6.5.2 Pressure Tests

7.6.5.2.1 All blowout prevention components that can be exposed to well pressure shall be tested first to a low pressure of 250 psi to 350 psi (1.72 MPa to 2.41 MPa) and then to a high pressure.

7.6.5.2.2 When performing the low-pressure test, do not apply a higher pressure and bleed down to the low-test pressure. The higher pressure can initiate a seal that can continue to seal after the pressure is lowered therefore, misrepresenting a low-pressure condition.

7.6.5.2.3 A stabilized low and high test pressure shall be maintained for at least 5 minutes with no visible leakage.

The allowable test pressure tolerance above rated working pressure shall be 5% of rated working pressure or 3.45 MPa (500 psi), whichever is less.

7.6.5.2.4 The predeployment high-pressure test on components that can be exposed to well pressure (BOP stack, choke/kill lines and valves, etc.) shall be performed in accordance with Table 9.

7.6.5.2.5 Choke and kill line connections shall be tested to the RWP of the ram BOPs, MASP, or the wellhead assembly pressure rating, whichever is lower.

Table 7—Subsea Testing of Secondary, Emergency, and Other Systems

System Type	Secondary Systems Test		Acceptance Criteria
	Components Function Tested	Frequency	
Acoustic	Communications.	Not to exceed 21 days between tests.	N/A
	One function.	One time during initial subsea BOP test.	N/A
ROV—critical functions (blind shear rams close, one pipe ram close, and LMRP unlock/unlatch)	One BSR or pipe ram.	One time annually subsea.	In 45 seconds or less [c.]
	LMRP connector.	Not required—consider functioning during storm evacuation, repair, maintenance, and end of well or program.	In 45 seconds or less [c.]
ROV – Non-sealing shear rams	Non-sealing shear rams	Prior to deployment	45 seconds or less
	Emergency Systems Test		
Deadman (or equivalent) [a]	All assigned components.	Commissioning or within 5 years of previous test [d.] Tested by removing control and hydraulic supply to the activation device.	In 90 seconds or less [c.]
Autoshear (or equivalent) [a]	All assigned components.	Commissioning or within 5 years of previous test [d.] Tested by activation of trigger, where applicable.	In 90 seconds or less [c.]
Emergency disconnect sequence [b]	All assigned components.	Commissioning or within 5 years of previous test.	In 90 seconds or less [c.]
Dedicated emergency accumulators	Accumulator volume.	At initial installation and subsequently every 6 months.	See 7.6.8.3.

[a] Unable to verify criteria when installed subsea on some systems.

[b] EDS not required on moored vessels.

[c] Minimal time requirement to secure the wellbore does not include functions after the well is secured.

[d] Drawdown test shall be performed in accordance with 7.6.8.3 to verify the accumulator capacity available on the stack.

Table 8—Other Systems Test

System Type	Type of Test	Frequency	Acceptance Criteria
Riser Recoil	Riser recoil test with BOP installed [a]	A controlled riser recoil test during commissioning, at rig acceptance (as per contract agreement), system design change or software changes to recoil system	In 120 seconds or less [c]
	Simulated function test on surface [b]	Yearly	In 120 seconds or less [c]

[a] Test is to be performed with BOP installed subsea (do not perform over or near subsea production infrastructure).

[b] A simulated test does not require installation of the BOP.

[c] Minimal time requirement to secure the wellbore, does not include functions after the well has been secured.

7.6.5.2.6 The initial subsea high-pressure test on all components, that could be exposed to well pressure (BOP stack, manifolds, lines and valves, IBOP, kelly valves, etc.) shall be tested in accordance with Table 10.

After relanding the LMRP onto the lower stack, the LMRP connector and choke and kill connections shall be tested to the initial pressure test requirements of Table 10.

7.6.5.2.7 The lower kelly valves, kelly, kelly cock, drill pipe safety valves, and top drive safety valves, should be tested with water from the wellbore side to a low pressure and to the RWP, MASP, or wellhead assembly pressure rating, whichever is lower.

7.6.5.2.8 There can be instances when the available BOP stack and/or the wellhead have higher working pressures than are required for the specific wellbore conditions due to equipment availability. Special conditions such as these should be covered in the site-specific well control pressure test program.

7.6.5.2.9 After landing the subsea BOP stack onto the wellhead, the BOP-to-wellhead connector shall be tested to a minimum of the highest MAWHP to be encountered in the entire well.

7.6.5.2.10 Subsequent high-pressure tests on the well control components shall be tested in accordance with Table 10.

7.6.5.2.11 With larger size annular BOPs, some small movement could continue within the large rubber mass for prolonged periods after pressure is applied and may require longer holding periods.

7.6.5.2.12 All well control valves (excluding choke/kill isolation test valves) shall be low- and high-pressure tested.

7.6.5.2.13 Valves that are required to seal against flow from both directions, shall be pressure tested from both directions.

7.6.5.2.14 Drifting the BOP shall be performed prior to deployment and upon completion of the initial BOP test on the wellhead assembly. This may be achieved using the test plug, wear bushing tools, or other large bore tools.

7.6.5.2.15 The minimum drift size for the BOP system in use, shall be determined by the equipment owner and user's requirements for the well(s) the equipment is installed upon.

7.6.5.3 Hydraulic Chamber Test

7.6.5.3.1 Hydraulic chamber tests shall be performed to the manufacturer's recommended maximum operating pressure.

7.6 5.3.2 The hydraulic chamber tests shall be performed on both the opening and the closing chambers of the equipment installed and the test results shall be documented.

7.6.5.3.3 When performing the chamber test, the pressure shall be stabilized for at least 5 minutes, with no visible leakage, to be considered an acceptable test result.

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

a) at least once yearly;

b) when equipment is repaired or remanufactured;

c) in accordance with the equipment owner's PM program.

7.6.5.4 Pressure Test Frequency

7.6.5.4.1 Pressure tests on the well control equipment shall be conducted

a) predeployment of the BOP subsea and upon installation;

b) after the disconnection or repair of any pressure containment seal in the BOP stack, choke line, kill line, choke manifold, or wellhead assembly but limited to the affected component;

c) in accordance with equipment owner’s PM program or site-specific requirements; and

d) not to exceed intervals of 21 days, excluding BSRs.

7.6.5.4.2 Blind shear rams shall be tested upon initial installation and at each subsequent casing point in accordance with Table 10.

7.6.5.4.3 A function test of the BOP control system shall be performed following the disconnection or repair, limited to the affected component.

7.6.5.4.4 Table 9 and Table 10 include a summary of the test practices for subsea BOP stacks and related well control equipment.

7.6.5.5 Test Fluids

7.6.5.5.1 The predeployment and initial installation pressure tests shall be conducted with water. During operations, the drilling fluid in use is acceptable to perform subsequent tests of the subsea BOP stack, to reduce the risk of an influx from hydrostatic pressure reductions.

7.6.5.5.2 Control systems and hydraulic chambers shall be tested using clean control system fluids with lubricity and corrosion additives for the intended service and operating temperatures.

7.6.5.6 Test Pressure Measurement Devices

7.6.5.6.1 Test pressure gauges, chart recorders, and/or data acquisition systems shall be used and all testing results shall be recorded.

7.6.5.6.2 It is acceptable for gauges to be used during the course of normal operations to read full scale but shall not serve as a test gauge.

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

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

7.6.5.6.5 Test pressure measurement devices (including analog gauges) shall be calibrated annually in accordance with OEM procedures.

7.6.5.6.6 Calibrations shall be traceable to a recognized national standard (NIST and ANSI).

7.6.5.7 Test Documentation

7.6.5.7.1 The results of all BOP equipment pressure and function tests shall be documented (see example worksheet Annex A)

7.6.5.7.2 Pressure tests shall be performed with a pressure recorder or equivalent data acquisition system and signed by the pump operator, contractor’s tool pusher, and operator’s representative.

7.6.5.7.3 Problems with the BOP equipment that results in an unsuccessful pressure test and actions to remedy the problems shall be documented.

7.6.5.7.4 The equipment owner shall notify the manufacturers of well control equipment that fails to perform in the field in accordance with Annex B.

Table 9—Pressure Test, Floating Rigs with Subsea BOP Stacks, Predeployment Testing

<table>
<tr><th>Component to Be Tested</th><th>Pressure Test—Low Pressure [a]
psi (MPa)</th><th>Pressure Test—High Pressure [b]
psi (MPa)</th></tr>
<tr><td>Annular preventer</td><td>250 to 350 (1.72 to 2.41)</td><td>Minimum of 70% of annular RWP.</td></tr>
<tr><td>Ram preventers</td><td></td><td></td></tr>
<tr><td>Fixed/variable ram</td><td>250 to 350 (1.72 to 2.41)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>Blind/blind shear</td><td>250 to 350 (1.72 to 2.41)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>Non-sealing shear rams</td><td>Function test</td><td>N/A</td></tr>
<tr><td>Hydraulic connectors</td><td>250 to 350 (1.72 to 2.41)</td><td>RWP of equipment above connector or wellhead system, whichever is lower.</td></tr>
<tr><td>Choke, kill, gas bleed line, and valves</td><td>250 to 350 (1.72 to 2.41)</td><td>RWP of ram preventers or wellhead system, whichever is lower.</td></tr>
<tr><td>BOP control system</td><td></td><td></td></tr>
<tr><td>Manifold and BOP lines</td><td>N/A</td><td>Control system operating pressure.</td></tr>
<tr><td>Accumulator pressure</td><td>Verify precharge</td><td rowspan="4">N/A</td></tr>
<tr><td>Close time</td><td rowspan="3">Function test</td></tr>
<tr><td>Pump capability</td></tr>
<tr><td>Control stations</td></tr>
<tr><td>Emergency and secondary systems</td><td>See Table 6 and Table 8.</td><td>See Table 6 and Table 8.</td></tr>
<tr><td colspan="3">Predeployment inspection and testing shall be performed in accordance with equipment owners’ PM program.</td></tr>
<tr><td colspan="3">a The low-pressure test should be stable for at least 5 minutes with no visible leaks.
b The high-pressure test should be stable for at least 5 minutes with no visible leaks.</td></tr>
</table>

7.6.5.8 General Testing Considerations

7.6.5.8.1 All personnel shall be alerted when pressure test operations are to be conducted, when testing operations are underway and when pressure testing has concluded.

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

7.6.5.8.3 Tightening, repair, or any other work shall be done only after verification that the pressure has been released and all parties have agreed that there is no potential of trapped pressure.

7.6.5.8.4 When testing from the cement unit, pressure shall be released only through pressure release lines and the return volume measured to confirm all pressure has been bled off.

7.6.5.8.5 All lines and connections that are used in the test procedures shall be adequately secured.

7.6.5.8.6 All fittings, connections, and piping used in pressure testing operations shall have pressure ratings equal to or greater than the maximum test pressure.

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

Table 10—Pressure Test, Floating Rigs with Subsea BOP Stacks, Subsea Testing

Component to Be Tested	Pressure Test—Low Pressure [a] psi (MPa)	Pressure Test—High Pressure [b c] psi (MPa)
Annular preventer, gas bleed line, valves, LMRP connector [e]	250 to 350 (1.72 to 2.41)	Minimum of MAWHP of the hole section or 70% of annular RWP, whichever is lower.
Ram preventers		
Fixed/variable ram	250 to 350 (1.72 to 2.41)	Initial pressure test, upon landing the BOP, pressure tested to the MAWHP for the well program for the stack installed. Subsequent tests, pressure tested to the MAWHP for the upcoming well section.
Blind shear and those valves immediately below the shear rams and above the upper pipe ram	250 to 350 (1.72 to 2.41)	Pressure tested at casing points to the casing test pressure. Function test interval not to exceed 21 days.
Non-sealing shear rams	Function test only	Function test interval not to exceed 21 days.
Wellhead or stack connector	250 to 350 (1.72 to 2.41)	Initial pressure test, upon landing the BOP, pressure tested to the MAWHP for the well program. Subsequent tests, pressure tested to the casing test pressure.
Choke, kill, gas bleed line, and valves [e]	250 to 350 (1.72 to 2.41)	Initial pressure test, upon landing the BOP, pressure tested to the MAWHP for the well program. Subsequent tests, pressure tested to the MAWHP for the upcoming well section (see 7.2.3.2.2).
Kill line and valves below a test ram	250 to 350 (1.72 to 2.41)	Same as ram preventer.
Choke manifold		
Upstream of choke(s)	250 to 350 (1.72 to 2.41)	Same as ram preventer.
Downstream of choke(s)	250 to 350 (1.72 to 2.41)	RWP of choke(s) outlet, valve(s), or line(s), whichever is lower.
Adjustable chokes	Function test only	Verification of backup control system.
BOP control system		Optional.
Manifold and BOP lines	N/A	N/A
Accumulator pressure	N/A	N/A
Close time	Function test	N/A
Control stations	Function test	N/A
Safety valves		
Kelly, kelly valves, drill pipe safety valves, IBOPs, etc.	250 to 350 (1.72 to 2.41)	Same as ram preventer.
Auxiliary equipment	N/A	N/A
Riser slip joint	Flow test	
Poor boy degasser/MGS [d]	Optional	
Trip tank, flo-show, etc.	Flow test	
Emergency and secondary systems	See Table 7 and Table 8.	See Table 7 and Table 8.
Subsea tests shall be performed upon initial installation, at intervals not to exceed 21 days (for wellbore testing) and/or in accordance with owner's PM program.		

[a] The low-pressure test should be stable for at least 5 minutes.

[b] The high-pressure test should be stable for at least 5 minutes. Flow-type test should be of sufficient duration to observe for significant leaks.

[c] Well control equipment may have a higher rated working pressure than required for the well site. The site-specific test requirements shall be used for these situations.

[d] The MGS requires a one-time hydrostatic test during manufacturing or upon installation. Subsequent welding on the MGS vessel shall require an additional hydrostatic test to be performed.

[e] Bleed valves shall be tested at annular pressure on the wellbore side and at MAWHP on the choke/kill line side.

7.6.5.8.8 The drill pipe test joint should be pipe that can withstand the tensile, collapse, and internal pressures that will be placed on it during the test operation.

7.6.5.8.9 A procedure shall be available to monitor pressure on the casing in the event the test plug leaks.

7.6.5.8.10 Flexible choke and kill lines shall be tested to the same pressure, frequency, and durations as the ram BOPs.

7.6.5.9 Subsea Well Hop

Upon latching to the subsequent well, all disconnected pressure containing BOP system connections shall be pressure tested to the MAWHP (per Table 10).

If MAWHP of the subsequent well exceeds test pressure of the previous well, the well control components shall be tested in accordance with Table 10. The well control components may be tested in accordance with Table 10 to provide a full 21 days before subsequent pressure testing is required.

Function testing shall be performed as per 7.6.5.1.

Upon latching to the subsequent well, disconnected control system connections shall be pressure tested to the RWP.

When drilling wells in different water depths without retrieving the BOP, the control system precharge values shall be calculated and set such that they are suitable for use in all of the intended water depths, per section 7.6.8.

Main accumulator systems that utilize the volume of the LMRP accumulators shall be tested in accordance with 7.6.8 for water depth variations greater than 250 feet.

The dedicated shear accumulators shall be tested in accordance with 7.6.8 for any of the following:

— water depth variations greater than 250 feet;

— increase in MAWHP of 500 psia or more above previous well test pressure;

— increase in drill pipe shearing requirements.

7.6.6 Subsea BOP Stack Equipment

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

7.6.6.2 Unless restricted by height, the entire stack (LMRP mated upon the lower BOP) should be pressure tested as a unit.

7.6.6.3 For the predeployment BOP test (stump test), the annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well drilling program.

7.6.6.4 For all subsea pressure tests, the annular BOP(s) and VBR(s) shall be pressure tested on the smallest OD drill pipe to be used in the hole section.

7.6.6.5 BSRs and/or CSRs shall not be tested when pipe is in the stack.

7.6.6.6 The capability of the shear ram and ram operator shall be verified with the manufacturer for the planned drill pipe. The shear ram preventer design and differences among drill pipe manufacturers can require higher closing pressures for shear operations.

7.6.6.7 When drill pipe hang-off is a possibility during well control, hang-off procedures shall be preplanned, utilizing the manufacturer's recommended hang-off load. Example hang-off procedures are included in API 59.

7.6.6.9 All ram-type BOPs with ram locks shall be pressure tested with the locks in the closed position and the closing and locking pressure vented during predeployment testing.

7.6.6.10 The BSR(s) and the hang-off ram BOP shall be pressure tested with locks in the locked position and closing and locking pressure vented, during the initial subsea test only.

7.6.6.11 The BOP elastomeric components that can be exposed to well fluids should be verified for compatibility with the drilling fluids to be used and for the anticipated temperatures to which it is exposed. Consideration should also be given to the temperature and fluid conditions during well testing and completion operations.

7.6.6.12 The manufacturer's markings for BOP 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.

7.6.6.13 Consider replacing critical BOP elastomeric components on well control equipment that has been out of service for 6 months or longer and has not been preserved according to equipment owner guidelines.

7.6.6.14 Valve actuator spring integrity shall be tested prior to deployment, for all well control valves, to confirm that the valve actuator will close or open the valve gate to its normal close or normal open position, without hydraulic assistance.

7.6.6.15 If visual position indicators are not available then, pressure testing or flow against the valve(s) shall be performed to determine the position of the valve.

7.6.6.16 Flexible choke and kill lines shall be tested to the same pressure, frequency, and duration as the ram preventers.

7.6.6.17 A precharged surge bottle can be installed adjacent to the annular preventer if contingency well control procedures include stripping operations.

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

7.6.7 Chokes and Choke Manifolds

7.6.7.1 The choke manifold upstream of and including the last high-pressure valves shall be tested to the same pressure as the ram preventers (see Table 10).

7.6.7.2 The adjustable chokes shall be operated daily to verify functionality.

7.6.7.3 Choke manifold valves should be serviced according to equipment owner's PM program.

7.6.7.4 The adjustable choke backup pneumatic/hydraulic control system shall be checked to ensure operation in the event of loss of primary supply in accordance with equipment owner's PM program.

7.6.7.5 The frequency of the choke drill shall be at initial installation and at each casing point, or in accordance with the equipment owner's PM program.

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

7.6.8 In-the-field Control System Accumulator Capacity

7.6.8.1 General

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

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

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

7.6.8.2 Drawdown Test

7.6.8.2.1 The purpose of this test is to verify that the main accumulator system, as described in 7.3.7.1, is properly sized to support the fluid volume and pressure requirements of the BOPs on the rig to secure the wellbore.

7.6.8.2.2 This test shall be performed prior to deployment and upon initial landing the BOPs, after any repairs that required isolation/partial isolation of the system and subsequently every 6 months from the previous test using the following example (see Annex A).

a) Position a properly sized joint of drill pipe or a test mandrel in the BOPs.

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

c) Record the initial accumulator pressure. Manifold and annular regulators shall be set at the manufacturer's recommended operating pressure for the BOP stack.

d) Close and open

   — the largest volume annular preventer and

   — the four smallest volume pipe ram preventers.

   Closing times shall meet the response times stipulated in 7.4.6.5.

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

   NOTE 1 When performing the accumulator drawdown test, wait a minimum of one hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test.

   NOTE 2 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 minutes after recording the pressure, if the pressure was less than 200 psi (1.38 MPa) above the precharge 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 200 psi (1.38 MPa) above precharge pressure has not been reached after 15 minutes you may have to wait an additional 15 minutes due to ambient temperatures negatively affecting the gas properties. After 30 minutes from the time the final pressure was recorded, if the 200 psi (1.38 MPa) above precharge has not been reached, then it will be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

7.6.8.3 The following test shall be performed upon initial landing the BOPs, after any repairs that required isolation/partial isolation of the system and subsequently every 6 months from the previous test.

In order to verify the functional volume of the dedicated emergency accumulators, they shall be isolated from the surface supply and the greatest consuming emergency sequence (excluding hydraulic connectors) supplied by the dedicated emergency accumulators shall be discharged. The pressure available after the function(s) is completed shall be adequate to secure the welland shall be recorded. See Annex C for examples of precharge calculations.

7.6.9 Inspections

7.6.9.1 Predeployment

7.6.9.1.1 Prior to deployment, the well control equipment should be cleaned, visually inspected, and PM performed.

7.6.9.1.2 The equipment owner's PM program shall address inspection (internal/external visual, dimensional, NDE, etc.) and pressure integrity testing.

7.6.9.1.3 Inspections shall be performed in accordance with documented equipment owner's reliability data.

7.6.9.1.4 Certain well operations or conditions (milling, well control events, bromide use, etc.) may require more frequent inspection and maintenance.

7.6.9.2 Inspection of Flexible Choke and Kill Hoses

The internal and external inspection programs shall be performed as specified by the equipment owner's PM program, in accordance with equipment manufacturer's recommendations. (Refer to API RP 7L for flexible line inspection procedures for additional guidance.)

7.6.9.3 Periodic Maintenance and Inspection

7.6.9.3.1 Well control equipment system components shall be inspected at least every 5 years in accordance with the equipment owner's PM program. Individual components and subassemblies may be inspected on a staggered schedule. The inspection results shall be verified against the manufacturer's acceptance criteria.

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

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

b) the date the new equipment (other than 7.6.9.3.1a), repaired equipment, or remanufactured equipment is installed into the system;

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

7.6.9.3.2 As an alternative to a schedule-based inspection program, the inspection frequency may vary from this 5 year interval if the equipment owner collects and analyzes condition based data (including performance data) to justify a different frequency.

7.6.9.3.3 For schedule and condition based inspection programs, shear ram blades, shear ram blocks, and blade retention bolts shall be inspected annually by visual inspection and surface NDE. The inspection results shall be verified against the manufacturer's acceptance criteria.

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

7.6.9.3.5 Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.

7.6.9.3.6 Documentation of all repairs and remanufacturing shall be maintained in accordance with 7.6.10.

7.6.9.4 Installation, Operation, and Maintenance Manuals

Rig-specific procedures shall be developed for the installation, operation, and maintenance (IOM) of BOP's for the specific well and environmental conditions. The IOM manuals shall be available on the rig for all BOP equipment installed on the rig.

7.6.9.5 Connections

7.6.9.5.1 Studs and nuts shall be checked for proper size, type, and grade after repair or remanufacture of components as recommended by API 6A, API 16A, or the OEM.

7.6.9.5.2 After a pressure seal is broken, the connection shall be established by applying the appropriate torque (in accordance with API 6A, API 16A, or OEM recommendations) to the connection studs and/or bolts.

7.6.9.5.3 Manuals or bulletins containing torque specifications shall be available on the rig.

7.6.9.5.4 Torque shall be applied to studs and/or bolts in a criss-cross manner or in accordance with OEM recommendations.

7.6.9.5.5 The appropriate torque shall be applied for the lubricant in use.

7.6.9.5.6 After the predeployment pressure test is completed, all bolts shall be rechecked for proper torque.

7.6.9.5.7 When making up proprietary (non-API) clamp hub connections, the manufacturer's recommended procedure shall be followed.

7.6.9.6 Replacement Assemblies

7.6.9.6.1 Replacement assemblies shall be designed for their intended use by industry approved and accepted practices. After installation of the replacement assembly, the affected pressure-containing equipment shall be pressure tested.

7.6.9.6.2 If replacement assemblies are acquired from a non-OEM, the assemblies shall be equivalent to or superior to the original equipment and be fully tested, design verified, and supported by traceable documentation in accordance with relevant API specifications.

7.6.9.6.3 Elastomeric components shall be stored in a manner recommended by the equipment manufacturer.

7.6.9.7 Equipment Storage

7.6.9.7.1 For BOPs, the rams or sealing element shall be removed and the internal BOP body/cavities thoroughly washed, inspected, and coated with a corrosion inhibitor, in accordance with equipment owner's and manufacturer's requirements.

7.6.9.7.2 For BOPs, the rams or sealing element should be removed and the internals washed, inspected, and coated with a corrosion inhibitor.

7.6.9.7.3 Connections should be covered and protected.

7.6.9.7.4 The hydraulic operating chambers should be flushed with a corrosion inhibitor and hydraulic connections plugged.

7.6.9.7.5 The equipment should be stored in a manner to protect it from environmental damage.

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

7.6.9.8 Weld Repairs

7.6.9.8.1 All welding of wellbore pressure containing and/or load-bearing components shall be performed in accordance with one of the following:

a) API 6A;

b) API 16A;

c) manufacturer's standards;

d) other applicable standards in consultation with the OEM.

7.6.9.8.2 All welding of wellbore pressure-containing components shall comply with the welding requirements of NACE MR0175/ISO 15156.

7.6.9.8.3 Verification of compliance shall be established through the implementation of a written WPS and the supporting PQR from the repair facility.

7.6.9.8.4 Welding shall be performed in accordance with a WPS, written and qualified in accordance with ASME *BPVC*, Section IX, Article II.

7.6.9.9 Poor Boy Degasser/Mud-Gas Separation Systems Inspection and Maintenance

7.6.9.9.1 Equipment owner’s PM program shall include removal of inspection plates and clearing of debris.

7.6.9.9.2 Vent ports and lines shall be inspected to ensure debris or other deficiencies do not impair the operability of the system.

7.6.9.9.3 An inspection program to consider corrosion and erosion shall be performed in accordance with the equipment owner’s PM program.

7.6.9.9.4 Inspect vent lines, in accordance with equipment owner's PM program, to ensure they are adequately braced.

7.6.9.9.5 Where installed, gauges shall be inspected for damage and operation and replaced, if found unfit for purpose, with a properly sized gauge for the rated system and pressure.

7.6.9.9.6 Pump water or drilling fluid into the degasser inlet and verify unobstructed flow.

7.6.9.9.7 If the degasser is equipped with a float to regulate liquid discharge, observe that the float properly regulates liquid discharge.

7.6.9.9.8 If manufactured to ASME code or equivalent specification, a one-time hydrostatic pressure test shall be performed in accordance with design codes, where test documentation does not currently exist.

7.6.9.9.9 If weld repairs are made to the poor boy degasser or mud/gas separator, NDE and inspection shall be performed in accordance with equipment owner’s PM program. A hydrostatic test shall be performed after welding on the mud/gas separator.

7.6.10 Quality Management

7.6.10.1 Planned Maintenance Program

7.6.10.1.1 A planned maintenance system, with equipment identified, tasks specified, and the time intervals between tasks stated, shall be employed on each rig.

7.6.10.1.2 Electronic and/or hard copy 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 the rig or service.

7.6.10.1.3 Electronic and/or hard copy records of remanufactured parts and/or assemblies shall be readily available and preserved at an offsite location, including documentation that shows the components meets or exceeds the OEM specifications.

7.6.10.2 Manufacturer's Product Alerts/Equipment Bulletins

7.6.10.2.1 Copies (electronic or paper) of equipment manufacturer's product alerts or equipment bulletins, for the equipment in use on the rig, shall be maintained at the rig site for the well control equipment and an offsite location.

7.6.11 Records and Documentation

7.6.11.1 General

7.6.11.1.1 Electronic and/or hard copies of all applicable standards and specifications, relative to the well control equipment shall be readily available.

7.6.11.1.2 The equipment owner shall be responsible for retaining records and documentation within the previous 2 year period at the rig site.

7.6.11.2 Posted Documentation

7.6.11.2.1 Drawings showing ram space out and bore of the BOP stack and a drawing of the choke manifold showing the pressure rating of the components shall be posted on the rig floor and maintained up to date (see Figure 14 for an example drawing).

7.6.11.2.2 A P&ID of the BOP control system shall be maintained on file at the rig.

7.6.11.2.3 Post calculated shear pressures on the rig floor and update in accordance with drilling operations (e.g. drill pipe properties, MAWHP, MEWSP, leak-off test, mud weights, etc.).

7.6.11.2.4 For tubulars requiring an annular closing pressure different than the normal [e.g. 1500 psi (10.34 MPa)], the closing pressure shall be obtained, posted and the regulator pressure adjusted prior to placing the tubular in the annular preventer.

7.6.11.2.5 Documentation shall include maximum riser angle, watch circle, etc.

7.6.11.3 Operation and Maintenance Manuals

7.6.11.3.1 Rig manuals, including equipment drawings, specifications and bills of material, shall be at the rig site to identify the equipment and assist with procuring correct replacement parts.

7.6.11.3.2 Modifications, alterations or adjustments from the original design or intent of the BOP and control system shall be documented through the use of a MOC system.

7.6.11.4 Equipment Data Book and Certification

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

7.6.11.4.2 Copies of the manufacturer's equipment data book and third-party certification shall be available for review.

7.6.11.4.3 Electronic and/or hard copy of all documentation shall also be retained at an offsite location.

7.6.11.5 Maintenance History and Problem Reporting

7.6.11.5.1 A maintenance and repair historical file shall be retained by serial number or unique identification for each major piece of equipment.

7.6.11.5.2 The maintenance and repair historical file shall follow the equipment when it is transferred.

7.6.11.5.3 Equipment malfunctions or failures shall be reported in writing to the equipment manufacturer in accordance with Annex B. The OEM shall respond to receiving the information and provide a timeline to provide failure resolution.

7.6.11.5.4 The equipment owner shall maintain a log of BOP and control system failures. The log shall provide a description and history of the item that failed along with the corrective action. The failure log shall be limited to items that provide wellbore integrity and the equipment used to function this equipment.

7.6.11.5.5 Details of the BOP equipment, control system and essential test data, shall be retained from the beginning to the end of well and considered for use in condition-based analysis.

7.6.11.5.6 Electronic and/or hard copy of all documentation shall also be retained at an offsite location.

7.6.11.6 Test Procedures and Test Reports

7.6.11.6.1 Testing after equipment weld remanufacturing shall be performed according to the manufacturer's written procedures.

7.6.11.6.2 Rig specific procedures for installation, removal, operation, and testing of all well control equipment installed shall be available and followed.

7.6.11.6.3 Pressure and function test reports shall be recorded and retained including preinstallation and all subsequent tests for each well.

7.6.11.6.4 Pressure and function test reports shall be retained for a minimum of 2 years at the rig site, and copies of these documents shall be retained at a designated offsite location.

7.6.11.6.5 Deadman, autoshear, EDS, acoustic, riser recoil, and other tests shall be performed in accordance with Table 6, Table 7, and Table 8 and retained on file at the rig site and a designated offsite location.

7.6.11.6.6 Pressure and function testing of all ROV critical functions shall be documented, detailing flow rates, test pressures and timing for actuation of the functions.

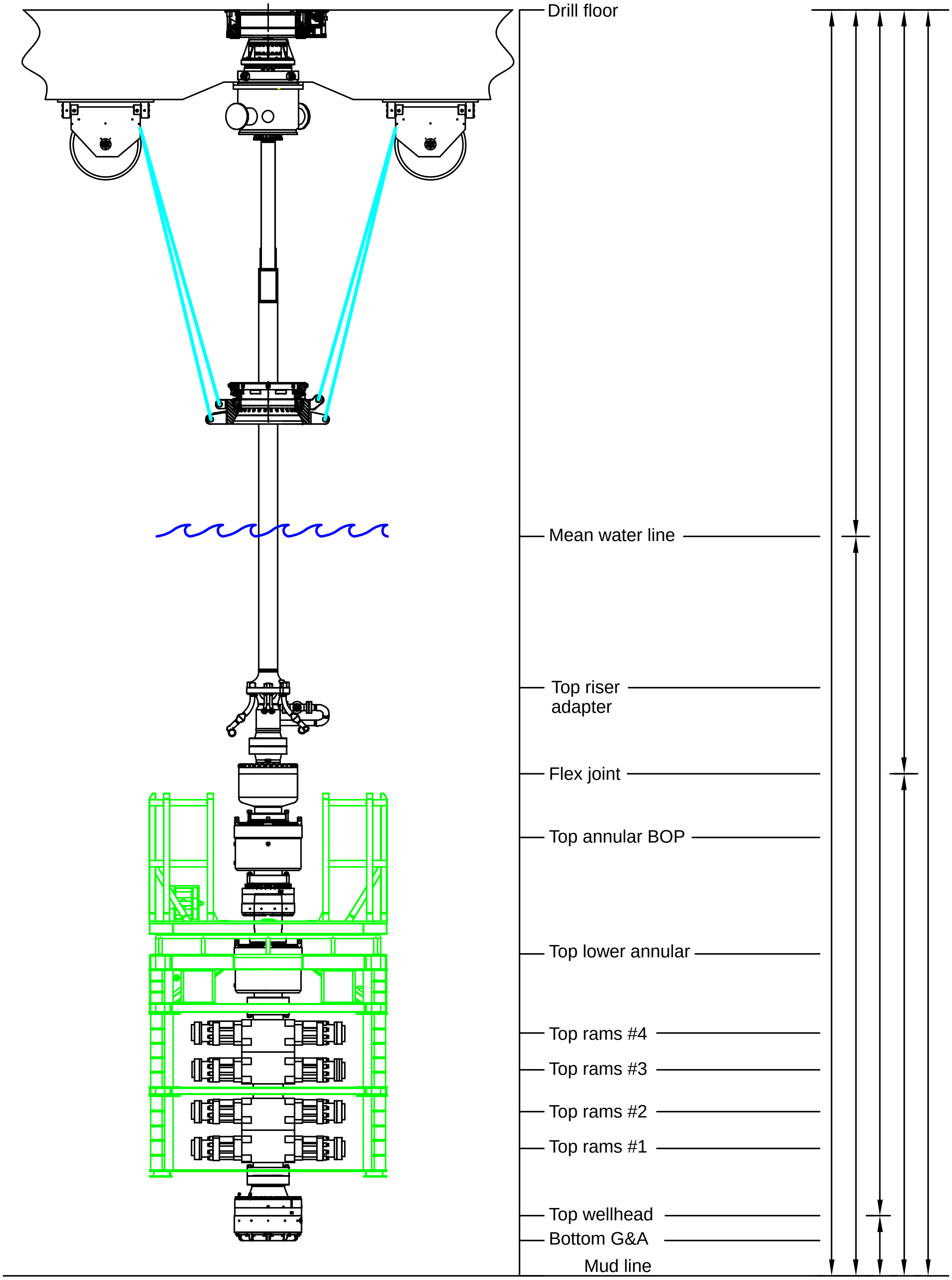

Figure 14—Example Illustration of Subsea Ram BOP Space-out

7.6.11.7 Shearing Pipe and Other Operational Considerations

7.6.11.7.1 Any identified well-specific risks shall be mitigated and/or managed through the development of specific guidelines, operational procedures, and a thorough risk assessment.

7.6.11.7.2 It is important to understand the effects of increasing wellbore pressure and its impact on the capability of shearing the drill pipe with a closed annular preventer. For this reason it is important to understand the equipment designs, their application/use, and those components run in the wellbore and the BOP/control systems in use.

7.6.11.7.3 To reduce the response time and complexity of the well control operations, the annular should be opened as soon as possible after closing the hang-off ram.

7.6.11.7.4 Consider limiting the MEWSP below the annular, to a specific pressure before reverting to a ram preventer to perform the well kill operation (see Table 11 for calculating MEWSP pressure).

7.6.11.7.5 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. An additional risk assessment should be performed if the shear pressure is higher than 90 % of the maximum operating pressure.

7.6.11.7.6 Consider one set of shear rams capable of shearing drill pipe and tubing that might be across the stack at MEWSP.

7.6.11.7.7 If the BSR or CSR is closed during a well control event, when pipe is sheared, the ram block shall be inspected and the BOP tested as soon as operations allow.

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

7.6.11.7.9 Calculated shear pressures shall be posted on the rig floor and updated in accordance with operations (e.g. drill pipe properties, MAWHP, MEWSP, leak-off test, mud weights, etc.) for all to view and be aware of those pressures. See Table 11 for an example of shearing calculations.

Table 11—Example Subsea MEWSP Calculations Given Well and Equipment-specific Data

Actual or Calculated Surface Shear Pressure psig (MPa)	**MAWHP at the Wellhead** psig (MPa)	**Shearing Ratio** (SR)	**Mud Weight Hydrostatic Pressure** psig (MPa)	**Control System Operating Pressure** psig (MPa)
2174 (14.99)	4000 (27.58)	14.64	2746 (18.93)	5000 (34.47)
With annular open: MEWSP = actual or calculated surface shear value + (hydrostatic pressure/SR) *Example: 2174 + (2746/14.64) = 2361 psig to shear pipe with the annular open* **With annular closed:** MEWSP = actual or calculated surface shear value + (MAWHP/SR) *Example: 2174 + (4000 /14.64) = 2447 psig (to shear pipe with MAWHP psi trapped under a closed annular)*				
NOTE 1 These equations show relative shear pressures. Accumulator calculations should use absolute pressures. NOTE 2 These calculations are presented as a simplified example only and are not intended to restrict the use of other methods.				

7.6.11.7.10 If shearing pressures approach the restart pressure (10 % threshold) of the accumulator charging pumps, the pump restart pressure should be increased nearer to the maximum operating pressure of the system.

7.6.11.7.11 If a single ram is incapable of both shearing and sealing the drill pipe or tubing in use, the emergency and secondary systems shall be capable of closing two rams; one that will shear and one that will seal wellbore pressure. Additional functions may be added but shall not interfere with the main purpose of shearing drill pipe and sealing the well.

7.6.11.7.12 In the event nonshearable equipment is across the BOP and the emergency and secondary system(s) have been disarmed, the priority of preserving life shall be given to disconnect the LMRP from the well. Rig-specific well control and equipment management procedures shall address this and other specific tasks.

7.6.11.7.13 Blowout preventers are designed to hold pressure from below. While in use, a closed preventer should not be subjected to a differential pressure from above, beyond the capabilities endorsed by the manufacturer. If such a condition develops, efforts shall be made to equalize the pressure differential before opening it. If the pressure differential was beyond manufacturer rating, the preventer shall be pressure tested as soon as operations allow.

Annex A
(informative)

Forms

The forms in Figure A.1, Figure A.2, Figure A.3, and Figure A.4 are example worksheets based on hypothetical blowout prevention equipment system. The forms in this annex are merely examples for illustration purposes only and each user of this standard should develop their own approach. They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied, for reliance on or any omissions from the information contained in this document.

EXAMPLE - SURFACE 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**

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

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

Figure A.1—Surface BOP Function Test Worksheet

EXAMPLE - SURFACE BOP SYSTEMS FIELD DRAWDOWN TEST WORKSHEET

Rig Name : ____________________ **Performed By:** ____________________

Date: ____________________ **BOP Class Designation:** ____________________

PUMP SYSTEM:

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

Pressure the secondary pumps turn on: __________ Pressure the secondary pumps turn of __________

Charging Pumps: Record the time it takes to pump up systems to meet both requirements. ____________

6.3.5.4 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.

6.3.5.5 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 system RWP within 30 minutes.

Surface accumulator precharge pressure: __________

Initial accumulator pressure: __________

Pressure Relief Valve Settings: __________

Ambient Temperature: __________ °F (°C)

ACCUMULATOR CLOSING TEST

Function	**Time.Sec.**	**Remaining Pressure**
Lower Pipe Ram	______	______
Middle Pipe Ram (if applicable)	______	______
Upper Pipe Ram	______	______
Blind Ram*	______	______
Annular	______	______
HCR Valve (open)	______	______

FINAL PRESSURE: __________

* Substitute functioning the upper pipe RAM a second time for functioning the blinds RAMs.

ACCUMULATOR PRESSURE

Is the final pressure ≥ 200 psi (1.38 Mpa) above precharge pressure? **Yes** **No**

Does the accumulator system function the RAMS and annulars with the proper time limits?

BOP control system shall be capable of closing 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**

NOTES:

NOTE 1 Closing times should be recorded and compared against the initial and 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 Closing times should be measured from the moment the function is activated to the initial moment the readback pressure gauge returns to its full operating pressure.

NOTE 4 When performing the accumulator drawdown test, wait a minimum of one hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test.

NOTE 5 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 200 psi (1.38 MPa) above the precharge 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 200 psi (1.38 MPa) above precharge pressure 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 the 200 psi (1.38 MPa) above precharge has not been reached, then it will be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

Figure A.2—Surface BOP Drawdown Test Worksheet

EXAMPLE - SUBSEA FUNCTION TEST WORKSHEET

Rig Name: ______________________________

Date: ______________________________

By: ______________________________

BOP Classification: ______________________________

Pod (+ SEM): ________________________ **Station:** ____________________

	Close		Open	
Function	**Time/Sec.**	**Vol.**	**Time/Sec.**	**Vol.**
Upper annular				
Lower annular				
Blind/blind shear				
Casing shear ram				
Lower pipe ram				
Middle pipe ram				
Upper pipe ram				
Upper outer kill				
Upper inner kill				
Lower outer kill				
Lower inner kill				
Upper outer choke				
Upper inner choke				
Lower outer choke				
Lower inner choke				
Wellhead connector (primary)				
Wellhead connector (secondary)				
LMRP connector (primary)				
LMRP connector (secondary)				

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

Each RAM BOP within in 45 seconds or less. **Yes** **No**

Closing time shall not exceed be 60 seconds for annular BOPs. **Yes** **No**

LMRP connector in 45 seconds or less. **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 A.3—Subsea Function Test Worksheet

EXAMPLE - SUBSEA BOP SYSTEMS FIELD DRAWDOWN TEST WORKSHEET

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

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

PUMP SYSTEM:

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

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

Charging Pumps: Record the time it takes to pump up systems to meet both requirements. __________

7.3.5.4 / 7.4.5.4 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.

7.3.5.5 / 7.4.5.5 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 system RWP within 30 minutes.

Surface accumulator precharge pressure: __________

Initial accumulator pressure: __________

Pressure Relief Valve Settings: __________

Ambient Temperature: __________ °F (°C)

ACCUMULATOR CLOSING TEST

Function		CLOSE Time.Sec.	CLOSE Remaining Pressure	OPEN Time.Sec.	OPEN Remaining Pressure
Lower pipe ram					
Middle pipe ram (if applicable)					
Upper pipe ram					
Blind shear ram[a]					
Annular					

FINAL PRESSURE: __________

[a] Substitute functioning the upper pipe ram a second time for functioning the blinds rams.

ACCUMULATOR PRESSURE

Is the final pressure ≥ 200 psi (1.38 Mpa) above precharge pressure? **Yes** **No**

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

Each ram BOP in 45 seconds or less. **Yes** **No**

Each annular BOP in 60 seconds or less. **Yes** **No**

NOTES:

NOTE 1 Closing times should be recorded and compared against the initial and 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 Closing times should be measured from the moment the function is activated to the initial moment the readback pressure gauge returns to its full operating pressure.

NOTE 4 When performing the accumulator drawdown test, wait a minimum of one hour from the time you initially charged the accumulator system from precharge pressure to operating pressure. Failure to wait sufficient time may result in a false positive test.

NOTE 5 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 200 psi (1.38 MPa) above the precharge 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 200 psi (1.38 MPa) above precharge pressure 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 the 200 psi (1.38 MPa) above precharge has not been reached, then it will be necessary to bleed down the system and verify precharge pressures and volume requirements for the system.

Figure A.4—Subsea BOP Field Drawdown Test Worksheet

Annex B
(normative)

Failure Reporting

B.1 User Recommendations

B.1.1 The equipment owner of blowout prevention equipment shall provide a written failure report to the equipment manufacturer of any malfunction or failure that occurs.

B.1.2 The failure report shall include the following:

a) as much information as possible on the operating conditions that existed at the time of the malfunction or failure;

b) an accurate a description as possible of the malfunction or failure;

c) any operating history of the blowout prevention equipment leading up to the malfunction or failure (e.g. field repair, modifications made to the blowout prevention equipment, etc.).

B.1.3 The manufacturer shall respond to receiving the failure report and provide a timeline to provide failure resolution.

B.2 Manufacturer's Recommendations

B.2.1 Manufacturer's Internal Recommendations

B.2.1.1 All significant problems experienced with blowout prevention equipment noted during its manufacture, testing or use shall be formally communicated to the individual or group within the manufacturer's organization responsible for the design and specification documents.

B.2.1.2 The manufacturer shall have a written procedure that describes forms and procedures for making this type of communication, and shall maintain records of progressive design, material changes, or other corrective actions taken for each model and size of blowout prevention equipment.

B.2.2 Manufacturer's External Recommendations

B.2.2.1 All significant problems experienced with blowout prevention equipment shall be reported in writing to each and every equipment owner of the blowout prevention equipment within three weeks after the occurrence.

B.2.2.2 The manufacturer shall communicate any design changes resulting from a malfunction or failure history to every equipment owner using the affected equipment. That notice shall be within 14 days after the design change.

Annex C
(informative)

Accumulator Precharge Calculation

C.1 Definitions

surface base pressure
Minimum operating pressure of the hydraulic circuit for supplying power to the function(s).

NOTE 1 This is usually a regulated 1500 psig (10.47 MPa).

NOTE 2 Exceptions are to special functions that have a specific pressure requirement, such as shear rams used to cut a specific tubular.

C.2 Accumulator Precharge Calculations

C.2.1 General

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

C.2.2 Method A

Method A calculations are based on an ideal gas, isothermal discharge. This calculation method shall not be used for accumulator systems with operating pressures above 5015 psia or that require rapid discharge of most of their fluid.

Method A calculations shall be accomplished using the following worksheet or equivalent API 16D formulas:

Rig- or well-specific data = Input$_{(x)}$
Transferred within worksheet = Transfer
Calculated from table data = *Calculated*

Minimum operating pressure = $(WD \times 0.445) + P_{\text{sb}} + 15$

Control fluid head (nonregulated circuit) = $\left[(WD + AG_{\text{hf}}) \times 0.052 \times W_{\text{hf}}\right] + P_{\text{s}} + 15$

Control fluid head (regulated circuit) = $(WD \times 0.052 \times 8.556) + P_{\text{s}} + 15$

Minimum Operating Pressure	Adjustment for water depth							Transfer$_1$		
	(WD	×	0.445)	+	P_{sb}	+	15	=	*Calculated*	psia

Supply Pressure (either a regulated or nonregulated circuit)													Transfer$_2$	
Control fluid head (nonregulated circuit)	((WD	+	AG_{hf})	×	0.052	×	W_{hf})	+	P_s	+	15	=	*Calculated*	psia
Control fluid (regulated circuit)	(WD		×	0.052		×	8.556 ppg)	+	P_s	+	15	=	*Calculated*	psia

Optimum precharge pressure P_0					MOP				Supply Pressure				Surface Precharge Pressure [a]	
	(1.0	/	((1.5	/	$Transfer_1$)	-	(0.5	/	$Transfer_2$)))	-	15	=	*Calculated*	psig

[a] Surface precharge pressure shall not exceed accumulator rated working pressure.

where

P_{sb} = surface base pressure, in psig;

P_s = supply pressure, in psig;

WD = water depth, in ft;

AG_{hf} = hydraulic fluid air gap, in ft;

W_{hf} = hydraulic fluid weight, in ppg;

P_o = optimum precharge pressure, in psig.

C.2.3 Method B

Method B calculations are based on a real gas, isothermal discharge. This calculation method shall not be used for accumulator systems that require rapid discharge of most of their fluid.

Method B calculations shall be accomplished using the following worksheet or equivalent API 16D formulas:

Rig or well specific data = $Input_{(x)}$
Transferred within worksheet = Transfer
Calculated from table data = *Calculated*
Data from NIST reference program = ***NIST***

Minimum operating pressure	Adjustment for water depth							Transfer$_1$	
	(WD	×	0.445)	+	P_{sb}	+	15	=	*Calculated*	psia

Supply pressure (either a regulated or nonregulated circuit)													Transfer$_2$	
Control fluid head (nonregulated circuit)	((WD	+	AG_{hf})	×	0.052	×	W_{hf})	+	P_s	+	15	=	*Calculated*	psia
Control fluid (regulated circuit)	(WD	×	0.052	*	8.556 ppg)			+	P_s	+	15	=	*Calculated*	psia

Using the NIST tables determine the MOP gas density, ρ_2, based upon operating temperature and minimum operating pressure.							
Operating condition	Pressure		Temperature			Density, $Transfer_3$	
MOP	$Transfer_1$	psia at	T_o	°F	=	***NIST***	lb/ft^3

Using the NIST tables determine the charged gas density, ρ_1, based upon operating temperature and supply pressure.							
Operating condition	Pressure		Temperature			Density, $Transfer_4$	
Accumulator charged	$Transfer_2$	psia at	T_o	°F	=	***NIST***	lb/ft^3

Optimum precharge density ρ_0					MOP				Supply Pressure		Precharge Density $Transfer_5$	
	1.0	/	((1.4	/	$Transfer_3$)	-	(0.4	/	$Transfer_4$))	=	*Calculated*	lb/ft^3

Using the NIST tables determine the gas pressure based upon precharge temperature and optimum precharge density.							
Operating condition	Density		Temperature			Surface Precharge Pressure*	
Accumulator precharge	$Transfer_5$	psia at	T_p	°F	=	***NIST***	psia

** - Surface precharge pressure shall not exceed accumulator rated working pressure.*

where

P_{sb} = surface base pressure, in psig;

P_s = supply pressure, in psig;

WD = water depth, in ft;

AG_{hf} = hydraulic fluid air gap, in ft;

W_{hf} = hydraulic fluid weight, in ppg;

T_o = operating temperature, in °F;

T_p = precharge temperature, in °F;

P_o = optimum precharge density, in lb/ft^3.

C.2.4 Method C

Method C calculations are based on a real gas, adiabatic discharge. This calculation method is required for accumulator systems that require rapid discharge of most of their fluid.

Documentation for sequenced method C systems shall include each sequenced step with the following applied:

— using the maximum MOP during each step;

— Funtional Volume Requirements shall be additive with each additional step;

— precharge pressure shall be maintained constant throughout each sequenced step.

Method C calculations shall be accomplished using the following worksheet or equivalent API 16D formulas:

Rig or well specific data = Input$_{(x)}$
Transferred within worksheet = Transfer
Calculated from table data = *Calculated*
Data from NIST reference program = ***NIST***

Function(s)	Text	Input	1
Surface base pressure	psig	Input	2
Functional volume requirement	Gallons	Input	3
Supply pressure	psig	Input	4
Surface ambient temperature	°F	Input	5
Maximum surface temperature	°F	Input	6
Operating ambient temperature	°F	Input	7
Water depth	Feet	Input	8
Hydraulic fluid air gap	Feet	Input	9
Riser air gap	Feet	Input	10
Maximum mud weight	ppg	Input	11
Shearing or closing ratio, whichever is higher (= 1 if not a ram)	Ratio	Input	12
Maximum anticipated wellhead pressure (relative to ambient)	psi	Input	13
Control fluid weight	ppg	Input	14
Accumulator system volume	Gallons	Input	15

Supply pressure (either a regulated or nonregulated circuit)													Transfer$_1$	
Control fluid head (nonregulated circuit)	((Input$_8$	+	Input$_9$)	×	0.052	×	Input$_{14}$)	+	Input$_4$	+	15	=	*Calculated*	psia
Control fluid (regulated circuit)	(Input$_8$		×	0.052		×	8.556 ppg)	+	Input$_4$	+	15	=	*Calculated*	psia

Using the NIST tables determine the charged gas density, ρ_1, and base entropy based upon gas temperature and pressure.									
Condition 1 data	Pressure		Temperature			Density, ρ_1 Transfer$_2$		Base entropy (B.P. conv.) Transfer$_3$	
Accumulator	Transfer$_1$	psia at	Input$_7$	°F	=	***NIST***	lb/ft^3	***NIST***	BTU/lb °F

Adjustment for depth (either riser head or closed in well pressure)										Transfer$_4$	
Riser head	((Input$_8$	+	Input$_{10}$)	*	0.052	*	Input$_{11}$)		=	*Calculated*	psi
Well pressure									=	Input$_{13}$	psi
Sea water pressure	Adjustment for water depth and hydraulic fluid head									Transfer$_{11}$	
Sea water head	(Input$_8$	*	0.052	*	8.556 ppg)	+	15		=	*Calculated*	psia

Adjustment for shearing or closing ratio									Transfer$_5$	
	(Transfer$_4$	-	Transfer$_{11}$	-	15)	/	Input$_{12}$	=	*Calculated*	psig

Minimum operating pressure (MOP)	Surface base pressure		Adjustment for Closing Ratio		Sea Water		Transfer$_6$	
Function(s)	Input$_2$	+	Transfer$_5$	+	Transfer$_{11}$	=	*Calculated*	psia

Using NIST tables determine the MOP gas density, ρ_2, based upon gas pressure and base entropy (held constant)									
Condition 2 Data	Pressure		Base entropy			Density, ρ_2, Trans$_7$		Temp Trans$_8$	
MOP requirement @ accumulator	Transfer$_6$	Psia at	Transfer$_3$	BTU/lb °F	=	***NIST***	lb/ft^3 at	***NIST***	°F

Accumulator Condition 0 Data—Method C									
Optimum precharge density $\rho_0 = \rho_2$	Transfer$_7$	lb/ft^3							
Using NIST tables determine the optimum precharge pressure based upon optimum precharge density and surface temperature									
	Density		Surface Temp			Optimum precharge		Optimum precharge	
Optimum precharge pressure at surf. Temp.	Transfer$_7$	at	Input$_5$	°F	=	***NIST***	psia	*Calculated*	psig

Using NIST tables determine the precharge gas density, ρ_0, based upon gas pressure and surface temperature									
	Surface Temp		Precharge Pressure			Pressure Trans$_9$		ρ_0 Transfer$_{10}$	
Input precharge pressure at surface	Input$_5$	°F	<u>User Selected</u>	psig	=	*Calculated*	psia	***NIST***	lb/ft^3

Using the NIST tables determine the gas pressure for the maximum surface temperature and precharge gas density ρ_0									
Pressure at maximum temperature	Precharge ρ_0		Maximum temp			Maximum pressure		Maximum pressure [a]	
	Transfer$_{10}$	lb/ft^3	Input$_6$	°F	=	***NIST***	psia	*Calculated*	psig

[a] User selected precharge should be lowered if pressure at maximum temperature exceeds bottle pressure rating.

Using the NIST tables determine the gas pressure for the operating temperature and precharge gas density ρ_0									
	Precharge ρ_0		Operating temp			Operating pressure		Operating pressure	
Pressure at subsea temperature, Cond. 0	$Transfer_{10}$	lb/ft^3	$Input_7$	°F	=	*NIST*	psia	*Calculated*	psig

Using the NIST tables determine gas temperature and density at ρ_3 limit, based upon Cond. 3 Sea water head pressure and constant base entropy.									
Condition 3 Data	Sea water pressure		Base entropy			Density, ρ_3, $Trans_{12}$		$Transfer_{13}$	
MOP requirement @ accumulator	$Transfer_{11}$	Psia at	$Transfer_3$	BTU/lb °F	=	*NIST*	lb/ft^3 at	*NIST*	°F

Calculate Basic data	Temp	Pressure surf equiv.	Pressure in bottle		Gas density, ρ
	°F	psig	psia		lb/ft^3
Tabulate temperatures and pressures psig and psia, and gas densities for each condition from above					
Condition 0: Precharged accumulators	$Input_7$	*Calculated*	$Transfer_9$	ρ_0	$Transfer_{10}$
Condition 1: Charged accumulators	$Input_7$	*Calculated*	$Transfer_1$	ρ_1	$Transfer_2$
Condition 2: Pressure Requirement (MOP)	$Transfer_8$	*Calculated*	$Transfer_6$	ρ_2	$Transfer_7$
Condition 3: Sea water hydrostatic limit	$Transfer_{13}$	*Calculated*	$Transfer_{11}$	ρ_3	$Transfer_{12}$

Using the NIST tables determine gas temperature and pressure for density = precharge density and constant entropy ($Transfer_3$)					
	°F	psig	Psia, $Trans_{14}$		Gas density, ρ
Trial Condition 3 case: Discharge all liquid	*NIST*	*Calculated*	*NIST*	ρ_0	$Transfer_{10}$

Use Method C density-based Volumetric Efficiency formulas:		
Pressure limited $VE_p = (\rho_0/\rho_2 - \rho_0/\rho_1)/1.1$	**VE_p**	*Calculated*
If $Transfer_{14} \geq Transfer_{11}$ then $VE_v = (1.0 - \rho_0/\rho_1)/1.1$	**VE_v**	*Calculated*
If $Transfer_{11} > Transfer_{14}$ then $VE_v = (\rho_0/\rho_3 - \rho_0/\rho_1)/1.1$	**or VE_v**	*Calculated*
Volumetric efficiency VE = min(VE_p, VE_v) = $Transfer_{15}$	**min. = VE**	*Calculated*

	Accumulator Volume		Volumetric Efficiency		Usable Volume $Transfer_{16}$
Calculate usable volume = accumulator volume * VE	$Input_{15}$	×	$Transfer_{15}$	=	*Calculated*
User selected precharge is acceptable if usable fluid volume ≥ functional volume requirement			$Transfer_{16}$	≥	$Input_3$

Annex D
(normative)

Acoustic System Field Testing

D.1 Purpose

The purpose of the field test is to verify the following:

— acoustic components are operating and decode commands correctly prior to deployment;

— surface equipment is tested as part of a predefined maintenance routine;

— surface-subsea link is verified and defined functions tested as part of a predefined maintenance routine.

D.2 Types of Tests

Standard test programs incorporate visual inspections, prelaunch functional tests, predefined routing functional tests.

D.3 Inspection Test

D.3.1 Prior to deployment of stack and acoustic subsea components, the following visual checks should be performed:

— check cabling to ensure no cuts/significant abrasions are visible;

— check transducers to ensure no physical knock have damaged them;

— check housings are not damaged/corroded.

D.3.2 The following visual tests can be carried out and recorded for surface equipment:

— visual check of cables;

— visual check of transducers.

D.4 Function Tests—Predeployment

Most acoustic systems include a test transducer and valve simulator box allowing activation of functions through the acoustic path without operating BOP stack. Tests to perform will be part of a predefined list to record outcome. This may include

— test of solenoid operation and read backs of solenoid status,

— test of power level and battery status, and

— test of preprogrammed sequence activation and replies, if applicable.

D.5 Function Tests—Post-deployment

During deployment various generic tests should be carried out at predefined test intervals.

a) Test surface unit, normally defined in the manual and includes

- battery capacity level and
- transmit tests (audible only).

b) Surface-to-subsea link and function test includes the following:

- acoustic link test;
- subsea battery level test;
- solenoid condition tests;
- accumulator pressure test via pressure sensor reading.

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