

Well Control Equipment Systems for Drilling Wells

API STANDARD 53
FIFTH EDITION, DECEMBER 2018

REAFFIRMED, MAY 2023



Special Notes

API publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

API publications may be used by anyone desiring to do so. Every effort has been made by the Institute to ensure the accuracy and reliability of the data contained in them; however, the Institute makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Any manufacturer marking equipment or materials in conformance with the marking requirements of an API standard is solely responsible for complying with all the applicable requirements of that standard. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API standard.

Classified areas may vary depending on the location, conditions, equipment, and substances involved in any given situation. Users of this Standard should consult with the appropriate authorities having jurisdiction.

Users of this Standard should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.

All rights reserved. No part of this work may be reproduced, translated, stored in a retrieval system, or transmitted by any means, electronic, mechanical, photocopying, recording, or otherwise, without prior written permission from the publisher. Contact the Publisher, API Publishing Services, 200 Massachusetts Avenue, NW, Washington, DC 20001.

Copyright © 2018 American Petroleum Institute

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

The verbal forms used to express the provisions in this specification are as follows:

- the term “shall” denotes a minimum requirement in order to conform to the standard;
- the term “should” denotes a recommendation or that which is advised but not required in order to conform to the standard;
- the term “may” denotes a course of action permissible within the limits of a standard;
- the term “can” is used to express possibility or capability.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, NW, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, NW, Washington, DC 20001.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Washington, DC 20001, standards@api.org.

Contents

	Page
1 Scope	1
2 Normative References	1
3 Terms, Definitions, and Abbreviations	2
3.1 Terms and Definitions	2
3.2 Abbreviations	11
4 Well Control Equipment General Requirements	12
4.1 BOP Equipment	12
4.2 Choke and Kill Equipment	13
4.3 BOP Control Systems (Land, Surface Offshore, Subsea)	15
4.4 Auxiliary Equipment	19
4.5 System Pressure Sealing Components	21
4.6 BOP Preventers for H ₂ S Service	23
4.7 Pressure Measurement Devices	24
5 Surface BOP Systems (Land and Surface Offshore)	25
5.1 Surface BOP Stacks	25
5.2 Choke Manifolds, Choke Lines, and Kill Lines-Surface BOP Installations	27
5.3 Testing-Surface BOP Systems	30
5.4 Inspection and Maintenance-Surface BOP Systems	35
6 Subsea BOP Systems	38
6.1 Subsea BOP Stacks	38
6.2 Choke Manifolds, Choke Lines, and Kill Lines-Subsea BOP Installations	41
6.3 BOP Control Systems (Subsea)	42
6.4 Testing-Subsea BOP Systems	44
6.5 Inspection and Maintenance-Subsea BOP Systems	49
Annex A (normative) Accumulator Pre-charge	53
Annex B (informative) Example Worksheets and Calculations	54
Annex C (normative) Testing	59
Annex D (normative) Failure Reporting	74
Bibliography	76
Figures	
1 Example Land and Surface Offshore BOP	26
2 Example 2K and 3K RWP Choke Line and Choke Manifold for Land and Surface Offshore	28
3 Example 5K RWP Choke Line and Choke Manifold for Land Example 5K Choke Line and Choke Manifold for Surface Offshore	29
4 Example 10K RWP or Greater Choke Line and Choke Manifold for Land Example 10K RWP or Greater Choke Line and Choke Manifold for Surface Offshore	29
5 Example 2K RWP Kill Line for Land and Surface Offshore	30
6 Example 3K or Greater RWP Kill Line for Land and Surface Offshore	30
7 Example 3K or Greater RWP Kill Line for Land and Surface Offshore	30
8 Example Subsea BOP	40
9 Example Subsea Choke Manifold	42
B.1 Example BOP Function Test Worksheet for Land and Surface Offshore	54
B.2 Example BOP Drawdown Test Worksheet for Land and Surface Offshore	55

Contents

	Page
B.3 Example BOP Function Test Worksheet for Subsea	56
B.4 Example BOP Function Test Worksheet for Subsea	57

Tables

1 Surface BOP Pressure Designations	25
2 Subsea BOP Pressure Designations	39
B.1 Example Surface MEWSP Calculations Given Well and Equipment-specific Data	58
B.2 Example Subsea MEWSP Calculations Given Well and Equipment-specific Data	58
C.1 Initial Function Testing, Surface BOP Stacks	59
C.2 Subsequent Operational Function Testing, Surface BOP Stacks	60
C.3 Scheduled Function Testing, Surface BOP Stacks	61
C.4 Initial Pressure Testing, Surface BOP Stacks	62
C.5 Subsequent Operational Pressure Testing, Surface BOP Stacks	63
C.6 Operating Chamber Pressure Testing, Surface BOP Stacks	64
C.7 Pre-deployment Function Testing, Subsea BOP Stacks	65
C.8 Initial Function Testing, Subsea BOP Stacks	67
C.9 Subsequent Operational Function Testing, Subsea BOP Stacks	68
C.10 Scheduled Function Testing, Subsea BOP Stacks	69
C.11 Pre-deployment Pressure Testing, Subsea BOP Stacks	70
C.12 Initial Pressure Testing, Subsea BOP Stacks	71
C.13 Subsequent Operational Pressure Testing, Subsea BOP Stacks	72
C.14 Operating Chamber Pressure Testing, Subsea BOP Stacks	73

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 Committee on Standardization of Oilfield Equipment and Materials.

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, the Third Edition of API 53 was issued in March 1997 and the Fourth Edition of API 53 was issued in November 2012. 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.

Well Control Equipment Systems for Drilling Wells

1 Scope

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

Well control equipment systems are designed with components that provide wellbore pressure control in support of well operations. The following components may be used for operation under varying rig and well conditions:

- BOPs (blowout preventers);
- Choke and kill lines;
- Choke manifolds;
- Control systems;
- Auxiliary equipment.

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

Diverter, 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.

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

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

To the extent that this document recommends specific equipment arrangements, it is recognized that other arrangements can be equally effective in addressing well requirements and achieving safety and operational efficiency.

2 Normative Reference

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 6A, *Specification for Wellhead and Tree Equipment*

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

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

API Specification 16C, *Choke and Kill Equipment*

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

API Recommended Practice 17H, *Remotely Operated Tools and Interfaces on Subsea Production Systems*

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), Section IX: *Welding and Brazing Qualifications*

NACE MR 0175/ISO 15156 2 3, (all parts) *Petroleum and natural gas industries—Materials for use in H₂S 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

Pressure vessel charged with inert gas and used to store hydraulic fluid under pressure.

3.1.2

acoustic control system

Subsea control system that uses coded acoustic signals for communications and is normally used as a secondary control system having control of selected functions.

3.1.3

adapter spool

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

3.1.4

annular blowout preventer

annular BOP

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

3.1.5

autoshear system

System designed to automatically shut in the wellbore in the event of a disconnect of the LMRP.

3.1.6

bell nipple

Piece of pipe, with an ID equal to or greater than the BOP bore, that is connected to the top of the BOP 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.

3.1.7**bleed line**

Flow line on the choke manifold that bypasses the chokes.

NOTE 1 This line allows circulation of the well with the preventers closed while maintaining a minimum backpressure.

NOTE 2 This line also permits the high-volume bleed-off of well fluids to relieve casing pressure with the preventers closed.

NOTE 3 Bleed lines can be referred to as panic lines.

3.1.8**blind ram**

Closing and sealing component in a ram BOP that seals the open wellbore.

3.1.9**blind shear ram****BSR**

Closing and sealing component in a ram BOP that first shears certain tubulars in the wellbore and then seals off the bore or acts as a blind ram if there is no tubular in the wellbore.

3.1.10**blowout**

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

3.1.11**blowout preventer****BOP**

Sealing ram or annular type device, which is within the scope of API 16A, 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, API 16ST well control components, intervention control packages, diverters, rotating heads, rotating control devices, rotating circulating devices, capping stacks, snubbing or stripping packages, or non-sealing rams.

3.1.12**BOP control system (closing unit)**

Equipment within the scope of API 16D used to operate the BOP stack.

3.1.13**BOP equipment**

Equipment within the scope of API 16A.

3.1.14**BOP stack**

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

3.1.15**BOP system**

BOP stack including the BOP controls system.

3.1.16**buffer chamber**

Chamber installed downstream of the chokes to allow manifolding of the bleed lines together.

3.1.17**casing shear ram****CSR**

Closing component in a ram BOP that is capable of shearing or cutting certain tubulars.

NOTE CSRs are not required to seal.

3.1.18**choke**

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

3.1.19**choke and kill equipment**

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

3.1.20**choke line valve****kill line valve**

Valve(s) connected to and a part of the BOP stack that control the flow to the choke and kill manifold.

3.1.21**choke line****kill line**

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

3.1.22**choke manifold**

Assembly of valves, chokes, gauges, and lines used to control the rate of flow and pressure from the well when the BOPs are closed.

3.1.23**clamp hub connection**

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.

3.1.24**closing ratio**

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.

3.1.25**competent person**

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

3.1.26**control fluid**

Hydraulic oil, water-based fluid, or gas that, under pressure, pilots the operation of control valves or directly operates functions.

3.1.27**control pod**

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.

3.1.28**control station/panel****remote control station/panel**

Panel containing an array of switches, push buttons, lights, valves, graphical user interfaces, pressure gauges, and/or meters used to control or monitor functions, pressures, and alarms.

NOTE A control station for a discrete hydraulic system can be at the HPU.

3.1.29**deadman system**

System designed to automatically shut in the wellbore in the event of a simultaneous absence of hydraulic supply and control of both subsea control pods.

3.1.30**dedicated accumulator system**

Accumulators exclusively used for a specific purpose that are supplied by the main accumulator system or a dedicated pump system, but not affected (e.g. by use of check valves) if the main supply is depleted or lost.

3.1.31**drill floor substructure**

Foundation structure(s) on which the derrick, rotary table, drawworks, and/or other drilling equipment are supported.

3.1.32**drill pipe safety valve**

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.

3.1.33**drilling spool**

Pressure-containing component having end connections and outlets that is used below or between drill-through equipment.

3.1.34**emergency disconnect sequence****EDS**

Programmed sequence of events that operates the functions to leave the stack and controls in a desired state and to disconnect the LMRP from the lower stack.

3.1.35**equipment manufacturer****original equipment manufacturer****OEM****current equipment manufacturer****CEM**

Design owner of the traceable assembled equipment, single equipment unit, or component part.

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

3.1.36

equipment owner

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

NOTE In most cases, this is the drilling contractor.

3.1.37

equipment user

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

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

3.1.38

fill-up line

Line usually connected into the diverter housing, or bell nipple, above the BOPs to facilitate adding drilling fluid to the hole at atmospheric pressure.

3.1.39

flex/ball joint

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

3.1.40

flow line

Piping that exits the bell nipple and conducts drilling fluid and cuttings to the shale shaker and drilling fluid pits.

3.1.41

full-bore valve

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

3.1.42

function test

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

3.1.43

gate valve

Valve that employs a sliding gate to open or close the flow passage.

NOTE The valve may or may not be full opening.

3.1.44

hang-off

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.

3.1.45

high pressure, high temperature

Well conditions 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.

3.1.46**hydraulic chamber test**

Application of a pressure test to any hydraulic operating chamber to verify integrity.

3.1.47**hydrogen sulfide****H₂S**

Highly toxic, flammable, corrosive gas sometimes encountered in hydrocarbon-bearing formations.

3.1.48**hydrostatic head**

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

3.1.49**initial test pressure****ITP**

API pressure designation that is equal to or above well program MASP for a land or surface offshore BOP system.

NOTE See Table 1 for API pressure designations.

3.1.50**inside blowout preventer****IBOP**

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 preventing back flow.

3.1.51**inspection test**

Examination or procedure that determine the existence of flaws that can influence equipment performance.

3.1.52**kelly valve**

Valve installed immediately above and below the kelly that can be closed to confine pressures inside the drill string.

3.1.53**kick**

Unintended influx of formation liquids or gas into the wellbore.

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

3.1.54**maintenance**

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

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

3.1.55**maintenance panel**

Control panel installed to provide control of the BOP for maintenance and testing purposes.

3.1.56**maintenance system**

System that is used to schedule and document preventive/planned maintenance activities and document corrective maintenance associated with rig equipment.

3.1.57**maximum anticipated surface pressure****MASP**

Highest surface pressure predicted to be encountered while the well control equipment is installed.

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

3.1.58**maximum anticipated wellhead pressure****MAWHP**

Highest subsea wellhead pressure predicted to be encountered while the well control equipment is installed.

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

3.1.59**maximum expected wellbore shear pressure****MEWSP**

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.

3.1.60**minimum operating pressure****MOP**

Minimum pressure differential required for a device to successfully perform its intended function in a particular environment (i.e. well specific).

3.1.61**minimum operator pressure for low-pressure seal****MOPFLPS**

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

3.1.62**mixing system**

System that mixes a measured amount of water-soluble lubricant and, optionally, antifreeze or conditioning agents into feed water and delivers it to a storage tank or reservoir.

3.1.63**mud/gas separator**

Vessel used to remove entrained gas in drilling fluid.

3.1.64**multiplex control system****MUX**

System utilizing electrical or optical conductors such that on each conductor, multiple distinct functions are independently operated by dedicated serialized coded commands.

3.1.65**pipe ram**

Closing and sealing component in a ram BOP that seals around the OD of a tubular in the wellbore.

3.1.66**pit volume indicator**

Device installed in the drilling fluid tank to register the fluid level in the tank.

3.1.67**pit volume totalizer**

Device that combines all of the individual pit volume indicators and registers the total drilling fluid volume in the various tanks.

3.1.68**pre-deployment test pressure****PDTP**

One API pressure designation above well program MAWHP for a subsea BOP system, not to exceed the rated working pressure (RWP) of the equipment being tested.

NOTE See Table 2 for API pressure designations.

3.1.69**pressure-containing**

Part whose failure to function as intended results in a release of wellbore fluid to the environment.

3.1.70**pressure-controlling**

Part intended to control or regulate the movement of wellbore fluids.

3.1.71**pressure test**

Periodic application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system.

3.1.72**rated working pressure****RWP**

Maximum internal pressure that equipment is designed to contain or control.

3.1.73**repair**

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

3.1.74**remanufacture**

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

3.1.75**shearing ratio****SR**

Area of the operating piston exposed to the close operating pressure during shearing operations divided by the cross-sectional area of the piston shaft exposed to wellbore pressure (generally the higher value of the closing ratios provided by the manufacturer).

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

3.1.76**spacer spool**

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

3.1.77**stable**

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

NOTE The documented acceptance criteria can include adjustments for different fluid types, air entrapment, compressibility, and temperature effects.

3.1.78**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 accumulator calculations as defined in API 16D and referenced in Annex A.

3.1.79**trip tank**

Low-volume (100 barrels [15.9 m³] or less) calibrated tank that can be isolated from the remainder of the surface drilling fluid system and used to accurately monitor the amount of fluid going into or coming from the well.

3.1.80**umbilical**

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

3.1.81**well control equipment**

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

3.1.82**wetted elastomeric seal**

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

3.2 Abbreviations

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

ANSI	American National Standards Institute
BOP	blowout preventer
BSR	blind shear ram
CEM	current equipment manufacturer
CSR	casing shear ram
EDS	emergency disconnect sequence
HPU	hydraulic power unit
H ₂ S	hydrogen sulfide
IBOP	inside blowout preventer
ID	inside diameter
IOM	installation, operation, and maintenance
ITP	initial test pressure
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
MOP	minimum operating pressure
MOPFLPS	minimum operator pressure for low-pressure seal
MUX	multiplex system
MWP	maximum working pressure
NACE	National Association of Corrosion Engineers
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	pipng and instrumentation diagram
PDTP	pre-deployment test pressure
PM	preventive maintenance
PQR	procedure qualification record
RCFA	root cause failure analysis
RWP	rated working pressure
SME	subject matter expert
SOP	standard operating procedure(s)
SR	shearing ratio
SWL	safe working load
VBR	variable-bore ram
WPS	weld procedure specification

4 Well Control Equipment General Requirements

4.1 BOP Equipment

4.1.1 Specifications for BOP Equipment

4.1.1.1 BOP equipment shall be in accordance with the edition of API 16A or API 6A that was in effect at the time of the equipment manufacture.

4.1.1.2 API 16AR should be used for BOP equipment remanufacturing.

4.1.1.3 Modifications, alterations, or adjustments from the original design or intent of the BOP system shall be documented through the use of the equipment owner's MOC (management of change) system.

4.1.2 BOP Stack Classifications

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

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

4.1.2.3 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 For example, a Class 6 BOP stack installed with two annular-type and four ram-type preventers is designated as "Class 6-A2-R4".

4.1.3 Adapter/Spacer Spools

4.1.3.1 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.

4.1.3.2 Adapter/spacer spools shall:

- a) Have a minimum vertical bore diameter equal to the internal diameter of the mating equipment;
- b) Have an RWP (rated working pressure) equal to or greater than the lowest RWP of the mating equipment;
- c) Have no penetrations capable of exposing the wellbore to the environment.

4.1.4 Drilling Spools

4.1.4.1 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.

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

4.1.4.2 Drilling spools for BOP stacks shall meet the following minimum requirements:

- a) For pressure-rated arrangements of 3K and 5K, have two side outlets no smaller than a 2 in. (5.08 cm) nominal size.
- b) For pressure-rated arrangements of 10K and greater, have two side outlets—one 3 in. (7.62 cm) nominal size as a minimum and one 2 in. (5.08 cm) nominal size as a minimum.
- c) 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) Have an RWP equal to the RWP of the installed ram BOP above the spool.

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

4.2 Choke and Kill Equipment

4.2.1 Specifications for Choke and Kill Equipment

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

The latest edition should be used for modifications, remanufactured equipment, or replacement equipment.

4.2.1.2 Modifications, alterations, or adjustments from the original design or intent of the choke and kill system shall be documented through the use of the equipment owner's MOC system.

4.2.2 Choke and Kill General

4.2.2.1 Choke and kill interconnect piping and piping downstream of the choke manifold shall be supported in accordance with ASME B31.3.

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

4.2.2.3 Choke and kill equipment shall meet the area classification requirements for the area in which it is installed.

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

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

4.2.2.5 If a component is used to connect the BOP or drilling spool outlet to the valves, the equipment owner's maintenance system shall include an inspection of the component for erosion at least every two years.

4.2.2.6 Use of the outlet below the lower-most ram BOP to take returns should be avoided.

4.2.3 Choke Manifold Equipment

4.2.3.1 For wells with a MASP (maximum anticipated surface pressure) of 3000 psi and greater, flanged, welded, and hubbed connections (as well as OECs [other end connections]) that are in accordance with API 6A and API 16A shall be employed on components subjected to well pressure.

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

4.2.3.3 Choke manifold valves shall be full bore.

4.2.3.4 When buffer chambers are employed, provision shall be available to re-direct the flow path and to isolate a failure or malfunction of the buffer chamber.

4.2.3.5 A choke manifold assembly shall include two adjustable chokes.

4.2.3.6 For land wells with a MASP of 3000 to 10,000 psi, at a minimum, one choke shall be remotely operable.

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

4.2.3.8 For offshore wells with a MASP of 3000 to 5000 psi, at a minimum, one choke shall be remotely operable.

4.2.3.9 For offshore wells with a MASP greater than 5000 psi, at a minimum, two chokes shall be remotely operable.

4.2.3.10 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.

4.2.3.11 Pressure ratings of all lines and sealing elements upstream of the chokes shall equal or exceed the MASP for the well program.

NOTE Pressure ratings for lines downstream of the adjustable choke outlet are not required to meet or exceed the MASP for the well program.

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

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

4.2.3.14 The remote choke control station shall include the ability to control the remotely adjustable choke(s) and to monitor casing pressure, standpipe pressure, and pump strokes.

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

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

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

4.2.4 Choke and Kill Lines

4.2.4.1 Choke and kill lines should be as straight as possible.

4.2.4.2 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).

4.2.4.3 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 maintenance system 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).

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

4.2.4.4 The flexible line manufacturer's MBR (minimum bend radius) guidelines should be followed.

4.3 BOP Control Systems (Land, Surface Offshore, Subsea)

4.3.1 Specifications for BOP Controls Equipment

4.3.1.1 BOP control systems shall be in accordance with the edition of API 16D that was in effect at the time of the control system manufacture. Systems designed before the first issue of API 16D shall meet the requirements of API 16D first edition as a minimum.

The latest edition should be used for modifications, remanufactured equipment, or replacement equipment.

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

4.3.2 BOP Controls General

4.3.2.1 BOP controls equipment shall meet the area classification requirements for the area in which it is installed.

4.3.3 Control Fluid

4.3.3.1 Control fluid (gases and liquids) shall be selected and maintained to meet minimum BOP equipment manufacturers and fluid supplier's properties, and the equipment owner's requirements.

4.3.3.2 The control fluid shall be maintained to prevent freezing when required.

4.3.4 Control Fluid Reservoir

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

4.3.5 Control Fluid Mixing System (If Applicable)

4.3.5.1 A check valve or some other automated means of preventing control fluid from returning or back flowing to the potable water supply shall be provided.

4.3.5.2 A manual override of the automatic mixing system shall be tested to ensure proper operation per the equipment owner's maintenance system.

4.3.6 Pump Systems

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

4.3.6.2 The two required pump systems shall have independent power sources.

NOTE Additional pump systems do not require independent power sources.

4.3.6.3 These pump systems shall be connected such that the loss of any one power source does not impair the operation of all the pump systems.

4.3.6.4 At least one pump system shall be available while the BOP is in operation.

4.3.7 Hydraulic Control Unit Location

4.3.7.1 The hydraulic control unit should be outside the drill floor substructure.

4.3.8 Accumulator Systems

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

4.3.8.2 Neither atmospheric air nor oxygen shall be used.

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

4.3.8.4 Subsea accumulators shall be discharged subsea prior to recovering the BOP stack to the surface or include a relief device to prevent over-pressurization of the circuit.

4.3.9 Main Accumulator System

4.3.9.1 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).

4.3.10 Dedicated Accumulator Systems

4.3.10.1 The dedicated accumulators shall be maintained (e.g. check valves) if the main supply is depleted or lost.

4.3.11 Accumulator Pre-charge

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

4.3.11.2 The pre-charge pressure on each stack-mounted accumulator bottle shall be measured prior to BOP stack deployment and adjusted in accordance with the API 16D method specified in the manufacturer's sizing documentation.

4.3.11.3 The manufacturer-supplied control system surface base pressure, adjusted for water depth and operating temperature, shall be used as required.

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

4.3.11.5 The calculated pre-charge pressures, along with documentation supporting nonoptimal pre-charge pressures (if used), shall be filed with the well-specific data package.

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

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

4.3.12 Accumulators, Valves, and Pressure Gauge Requirements

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

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

4.3.12.3 Accumulator pre-charge pressure gauges shall meet the requirements of 4.7.1.

4.3.13 Control System Interconnect Valves, Fittings, Lines, and Components

NOTE 1 This section applies to rigid or flexible control lines between the control system and BOP stack(s) or between control system assemblies (e.g. HPUs [hydraulic power units], accumulator skids, etc.).

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

4.3.13.2 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.

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

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

4.3.13.5 For BOP systems that do not include a deadman system, control lines and end connections between the control system and BOP stack(s) located in a Div 1 or Div 2 area as defined in API RP 500 or a Zone 1 or Zone 2 area as defined by API RP 505 shall meet the requirements of API 16D, including fire test requirements.

NOTE 2 For BOP systems that include a deadman system, 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 3 The use of fire-retardant hoses can delay or prevent the activation of a deadman system.

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

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

4.3.14 Control Stations

4.3.14.1 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.

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

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

4.3.14.4 Control systems shall clearly identify each function and the function position (e.g. open, closed, etc.).

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

- a) Shear rams close;
- b) Blind rams close;
- c) Riser connector primary and secondary unlock (LMRP [lower marine riser package] connector unlock);
- d) Wellhead connector primary and secondary unlock;
- e) Choke and kill hydraulic connectors unlock or stabs retract;
- f) Pod stab retract or unlock functions;
- g) Emergency disconnect sequence.

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

- a) Surface accumulator pressure;
- b) Regulated manifold pressure;
- c) Regulated annular pressure;
- d) Air supply pressure;
- e) Manifold and annular read-backs;
- f) Flow metering;
- g) LMRP accumulator pressure;
- h) Stack accumulator pressure;
- i) Pod supply pressure;
- j) Pilot supply pressure;