

Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

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Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment

1 Scope

These specifications establish minimum design standards for systems used to control blowout preventers (BOPs) and associated valves that control well pressure during drilling operations. The requirements in this specification apply to the following control system categories:

- a) control systems for land based and surface-mounted BOP stacks;
- b) discrete hydraulic control systems for subsea BOP stacks;
- c) electro-hydraulic/multiplex (MUX) control systems for subsea BOP stacks;
- d) emergency control systems for subsea BOP stacks;
- e) secondary control systems for subsea BOP stacks; and
- f) control systems for diverter equipment.

The design standards applicable to subsystems and components do not include material selection and manufacturing process details but may serve as an aid to purchasing. Although diverters are not considered well control devices, their controls are often incorporated as part of the BOP control system. Thus, control systems for diverter equipment are included.

Control systems for drilling well control equipment typically employ stored energy in the form of pressurized hydraulic fluid (power fluid) to operate (open and close) the BOP stack components. Each operation of a BOP or other well component is referred to as a control function. The design of control system equipment and circuitry varies in accordance with the application and environment.

2 Normative References

The following documents contain provisions which, though referenced in this text, constitute provisions of this standard. For dated references, only the edition cited applies. For undated references, the latest edition of the reference document (including amendments) applies.

ANSI/ESD S20.20, *Protection of Electrical and Electronic Parts, Assemblies, and Equipment*

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

API Standard 53, *Blowout Prevention Equipment Systems for Drilling Wells*

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

API Recommended Practice 505, *Recommended Practice for Classification of Locations for Electrical Installation at Petroleum Facilities Classified as Class 1, Zone 0, Zone 1 and Zone 2*

API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*

ASME B31.3, *Process Piping; ASME Code for Pressure Piping*

ASME B40.100, *Pressure Gauges and Gauge Attachments*

ASME, *Boiler and Pressure Vessel Code (BPVC), Section VIII, Division 1, Rules for Construction of Pressure Vessels*

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

ASTM A370, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*

IEC 60079 (All Parts), *Explosive Atmosphere Standards*

IEC 60529, *Degrees of Protection Provided by Enclosures (IP Code)*

IEC 60617, *Graphical Symbols for Diagrams*

IEC 60812, *Analysis techniques for system reliability—Procedure for failure mode and effects analysis (FMEA)*

IPC J-Std-0001, *Requirements for Soldering Electronic and Electrical Assemblies*

IPC 610, *Acceptability of Electronic Assemblies*

IPC 620, *Requirements and Acceptance of Cable and Wire Harnesses Assemblies*

IPC-7711/7721, *Rework, Repair and modifications of Electronic Assemblies*

ISO 1219, *Fluid Power symbols and components—Graphical symbols and circuit diagrams*

NACE SP0176, *Corrosion Control of Submerged Areas*

NFPA 70, *National Electrical Code*

NFPA 496, *Standard for Purged and Pressurized Enclosures for Electrical Equipment*

NEMA 250, *Enclosures for Electrical Equipment (1000 Volts Maximum)*

United States Department of Transportation (DOT) Specification 3AA2015

3 Terms, Definitions, and Abbreviations

3.1 Terms and Definitions

For the purposes of this specification, the following terms and definitions apply:

3.1.1

absolute pressure

The pressure referenced against a vacuum.

3.1.2

accumulator

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

3.1.3

accumulator bank

Assemblage of multiple accumulators sharing a common manifold.

3.1.4**accumulator precharge
precharge**

Initial inert gas charge in an accumulator, which is further compressed when the hydraulic fluid is pumped into the accumulator, thereby storing potential energy.

3.1.5**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 a few selected critical functions.

3.1.6**air pump/air-powered pump**

Air driven hydraulic piston pump.

3.1.7**annular BOP**

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

3.1.8**arm**

To enable the operation of a critical function or functions.

3.1.9**autoshear system**

Emergency control system that automatically activates in the event of a disconnect of the LMRP.

3.1.10**backup**

Element or system that is intended to be used only in the event that the primary element or system is non-functional.

3.1.11**blind ram BOP**

BOP having rams that seal the open wellbore.

3.1.12**blind shear ram**

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

3.1.13**black box test**

Test designed to verify the functionality of a software unit by creating a sufficient number of test cases to ensure that the functionality defined in the software design specification is thoroughly exercised and produces the correct set of outputs for a given set of inputs.

3.1.14**block position**

Center position of a three-position control valve.

NOTE 1 The position blocks supply pressure, preventing function activation with the valve.

NOTE 2 It may or may not vent control fluid from the function, depending on the valve design.

3.1.15**blowout**

Uncontrolled flow of pressurized wellbore fluids.

3.1.16**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 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 non-sealing rams.

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

System of pumps, valves, accumulators, fluid storage and mixing equipment, manifold, piping, hoses, control panels and other items necessary to hydraulically operate the BOP equipment.

3.1.18**BOP stack**

Complete assembly of well control equipment including BOPs, spools, valves, and nipples connected to the top of the wellhead or wellhead assemblies.

3.1.19**casing shear ram**

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

NOTE Casing shear rams are not required to seal.

3.1.20**central control unit**

Central control point for control and monitoring system functions and communications.

3.1.21**check valve**

Valve that allows flow through it in one direction only.

3.1.22**choke or kill line**

High-pressure line that allows fluids to be pumped into or removed from the well with the BOPs closed.

3.1.23**choke and kill valves**

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

3.1.24**close and seal**

Operation of a BOP to close the wellbore and obtain a wellbore pressure seal.

3.1.25**closing ratio (ram BOP)**

Effective wetted cross-sectional area of the piston(s) divided by the cross-sectional area of the piston rod.

3.1.26**commodity item**

Manufactured product purchased by the control system manufacturer for use in the construction of control systems for drilling well control equipment.

3.1.27**control fluid**

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

3.1.28**control hose bundle
hose bundle**

Group of pilot or supply, or both; or control hoses, or a combination thereof, assembled into a bundle covered with an outer protective sheath.

3.1.29**control line**

Flexible hose or rigid line that transmits control fluid.

3.1.30**control manifold**

Assemblage of valves, regulators, gauges and piping used to regulate pressures and control the flow of hydraulic power fluid to operate system functions.

3.1.31**control pod**

Assemblage of valves and pressure regulators which respond to control signals to direct hydraulic power fluid through assigned porting to operate functions.

3.1.32**control station**

Array of switches, push buttons, lights, valves, graphical user interface, pressure gauges, meters, or a combination thereof, used to control or monitor functions, pressures, and alarms.

3.1.33**control valve**

Component that directs power fluid to operate a selected function.

3.1.34**critical**

Element or system that deemed by the organization, product specification, or customer as mandatory, indispensable or essential, needed for a stated purpose or task, and requiring specific action.

3.1.35**deadman system**

Emergency control system that automatically activates in the event of a main control system failure.

3.1.36**dedicated**

Element or system that is exclusively used for a specific purpose, and is precluded for any other purpose.

3.1.37**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.

3.1.38**design validation**

Process of proving a design by testing and provision of evidence to demonstrate conformity of the product to design requirements.

3.1.39**design verification**

Process of examining the result of design and development output to determine conformity with specified requirements.

3.1.40**differential pressure**

The difference in pressure between any two points.

3.1.41**disarm**

To disable the operation of a critical function or functions.

3.1.42**disconnect**

To unlatch and separate the LMRP connector from its mandrel or the BOP stack connector from the wellhead.

3.1.43**discrete hydraulic control system**

System using pilot hoses to transmit hydraulic pressure signals to activate pilot-operated valves assigned to functions.

3.1.44**diverter**

Device attached to the wellhead or marine riser to close the vertical flow path and direct well flow (typically shallow gas) into a vent line away from the rig.

3.1.45**drift-off**

Unintended lateral move of a dynamically positioned vessel off of its intended location relative to the well-head, generally caused by loss of station keeping control or propulsion.

3.1.46**drive-off**

Unintended lateral move of a dynamically positioned vessel off its location driven by the vessel's main propulsion or station keeping thrusters.

3.1.47**dunking transducer**

Portable device capable of sending and receiving acoustic signals.

3.1.48**dynamic positioning**

Computerized means of maintaining a vessel on location by selectively driving thrusters.

3.1.49**electric pump**

Electrically driven hydraulic pump, usually a three-plunger (triplex) pump.

3.1.50**electro-hydraulic control system****EH**

System utilizing electrical conductor wires in an armored subsea umbilical cable to transmit command signals to solenoid-operated valves which in turn activate pilot-operated control valves assigned to functions.

NOTE One pair of wires is dedicated to each function.

3.1.51**factory acceptance testing**

Testing by a manufacturer of a particular product to validate its conformance to performance specifications and ratings.

3.1.52**failure modes and effects analysis****FMEA**

Reliability assessment process whereby all possible failure modes of a system are identified, and the probability and effects on the system performance are assessed.

3.1.53**function**

Operation of a BOP, choke or kill valve or other component, in one direction (example, closing the blind rams is a function, opening the blind rams is a separate function).

3.1.54**gauge pressure**

The differential pressure relative to ambient pressure.

3.1.55**hydraulic conduit**

Auxiliary line on a marine drilling riser used for transmission of control fluid between the surface and the subsea BOP stack

3.1.56**hydraulic connector**

Hydraulically actuated drill-through equipment that locks and seals on end connections.

3.1.57**interflow**

Control fluid lost (vented) during the travel of the piston in a control valve during the interval when the control valve's inlet and vent ports are temporarily interconnected.

3.1.58**integration test (software)**

Test method to ensure the software units (after completing unit testing) work together.

NOTE 1 Usually, the system is built from the bottom-up by performing integration testing on groups of units at the lowest level first and building up the system by adding more units and more groups of units that have already completed their integration testing.

NOTE 2 The goal of integration testing is to ensure that the output from one unit is correct as the input to another unit; and to ensure that the functionality between the units exists and works as expected.

3.1.59

interlock sequencing

Arrangement of control system functions designed to require the actuation of one function as a prerequisite to actuate another function.

3.1.60

jumper

Segment of hose or cable used to make a connection such as a hose reel junction box to the control manifold.

3.1.61

junction box (electrical)

Enclosure used to house the termination points of electrical cables and components that may also contain electrical components required for system operation.

3.1.62

junction box (hydraulic or pneumatic)

Bolt-on plate having multiple stab-type terminal fittings used for quick connection of the multi-hose bundle to a pod, hose reel or manifold.

3.1.63

lower marine riser package

LMRP

Remotely disconnectable upper section of a two-section subsea BOP stack that can be quickly disconnected.

NOTE A typical LMRP consists of the hydraulic connector, annular BOP(s), flex/ball joint, riser adapter, flexible choke and kill lines, and subsea control pods.

3.1.64

lowest maintainable subassembly

Lowest level field replaceable component or assembly as defined in a FMEA.

3.1.65

limit switch

Hydraulic, pneumatic or electrical switch that indicates the end of motion or extreme position of a device.

3.1.66

main accumulator system

Equipment that consists of the surface accumulator system and any LMRP mounted accumulators (if applicable) that are part of the main control system (not dedicated accumulators for the diverter, emergency, or secondary systems).

3.1.67

manifold

Assemblage of pipe, valves, and fittings by which fluid from one or more sources is selectively directed to various systems or components.

3.1.68

manipulator valve

Four way three position (typically) control valve where the center position blocks supply and pressure and vents both function ports.

3.1.69**minimum operating pressure****MOP**

Minimum pressure differential required for a device to successfully perform its intended function in a particular environment.

3.1.70**Minimum Operator Pressure for Low Pressure Seal****MOPFLPS**

BOP operator pressure required to obtain a wellbore seal.

3.1.71**mixing system**

System that mixes a measured amount of water soluble lubricant and, optionally, glycol to feed water and delivers it to a storage tank or reservoir.

3.1.72**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.

3.1.73**pilot fluid**

Control fluid that is dedicated to the pilot supply system.

3.1.74**pilot line**

Line that transmits pilot fluid to operate a control valve.

3.1.75**pipe ram BOP**

Ram BOP that seals around the outside diameter of a tubular in the wellbore.

3.1.76**pop-up display****control dialog box**

Display or control that appears on a computer screen to allow increased access to a control item or to display auxiliary data, a message, or a supplemental operational request or a system alarm notification.

3.1.77**power fluid**

Pressurized fluid dedicated to the direct operation of functions.

3.1.78**pressure**

Ratio of force to the area over which that force is distributed.

3.1.79**pressure-biased control system**

Discrete hydraulic control system utilizing a means to maintain an elevated pressure level (less than control valve actuation pressure) on pilot lines such that hydraulic signal transmission time is reduced.

3.1.80**pressure-containing component**

Component whose failure to function as intended results in a release of retained fluid to the environment.

3.1.81**pressure vessel**

For BOP control systems, a container for the containment of internal fluid pressure or for the exclusion of external pressure.

3.1.82**qualification test**

One-time (prototype) test program performed on a newly designed or significantly redesigned control system or component to validate conformance to design specifications.

3.1.83**ram BOP**

BOP that uses rams to seal off pressure in the wellbore.

3.1.84**rated working pressure****RWP**

Maximum internal pressure that equipment is designed to contain or control under normal operating conditions.

3.1.85**readback**

Indication of a remote condition.

3.1.86**reel (hose or cable)**

Reel, usually power driven, that stores, pays-out and takes-up umbilicals, hoses, or electrical cables.

3.1.87**regulator (valve)**

Hydraulic device that reduces upstream supply pressure to a desired (regulated) pressure

NOTE It is manually or remotely operated and maintains the regulated output pressure unless reset to a different pressure.

3.1.88**relief valve**

Device that is built into a hydraulic or pneumatic system to relieve (dump) any excess pressure.

3.1.89**reservoir**

Storage tank for BOP control system fluid.

3.1.90**response time**

Time elapsed between activation of a function at any control panel and complete operation of the function.

NOTE For automated functions, the start time is when the conditions are met for the automated response to initiate.

3.1.91**return-to-reservoir circuit**

Hydraulic control circuit in which spent fluid is returned to the reservoir.

3.1.92**rigid conduit**

Hydraulic supply line from surface to subsea, composed of pipe attached to the riser.

NOTE See hydraulic conduit.

3.1.93**riser connector****LMRP connector**

Hydraulically operated connector that joins the LMRP to the top of the lower BOP stack.

3.1.94**risk**

Situation or circumstance that has both a likelihood of occurring and a potentially negative consequence.

3.1.95**seal pressure**

BOP operator pressure required to effect a wellbore seal.

3.1.96**shared**

Element or system that may be used for more than one purpose.

3.1.97**shear and seal**

Operation to shear a tubular in the wellbore and obtain a wellbore pressure seal.

NOTE See also MOPFLPS.

3.1.98**shear pressure**

Ram BOP operator pressure required to shear.

3.1.99**shear ratio (shear ram BOP)**

The effective operator closing area for shearing divided by the ram shaft area.

3.1.100**sheave**

Wheel or rollers with a cross-section designed to allow a specific size of rope, cable, wire line or hose bundle to be routed around it at a fixed bend radius that is normally used to change the direction of, and support, the line.

3.1.101**shuttle valve**

Valve with two or more supply ports and only one outlet port.

NOTE When fluid is flowing through one of the supply ports the internal shuttle seals off the other inlet port(s) and allows flow to the outlet port only.

3.1.102**software topology**

Schematic representation of the electronic components, network connections, software applications installed and the interfaces between the software applications.

3.1.103**software unit**

Smallest amount of software that has a set of inputs, produces a set of outputs, and can be compiled into an executable (or interpreted) code unit (or component or module).

3.1.104**solenoid valve**

Electrical coil operated valve which controls a hydraulic or pneumatic function or signal.

3.1.105**spent fluid**

Hydraulic control fluid that is vented from a function control port.

3.1.106**stored hydraulic fluid volume**

Fluid volume recoverable from the accumulator system between the system rated working pressure and the precharge pressure.

3.1.107**system rated working pressure**

Maximum design pressure at which control fluid is stored in the accumulator assembly.

3.1.108**test pressure**

Pressure at which the component or system is tested to verify structural and pressure integrity.

3.1.109**umbilical**

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

3.1.110**unit test**

Test method by which software units created by the software developer(s) is verified to function correctly per design specification and that they meet the organizations quality standards.

3.1.111**vent position**

Position of a control valve that vents spent fluid to the reservoir or to the environment.

3.1.112**volumetric efficiency (general)****VE**

The ratio of the amount of control fluid than can be delivered under certain conditions to the total gas volume of the accumulator.

NOTE Volumetric efficiencies used in accumulator sizing calculations are listed in Annex C.

3.1.113**water-based hydraulic fluid**

Control liquid mixture composed mainly of water with additives to provide lubricity, antifoaming, antifreeze, anticorrosion and antibacterial characteristics.

3.1.114**wellhead connector****stack connector**

Hydraulically-operated connector that joins the BOP stack to the subsea wellhead.

3.1.115**white box test**

Test designed to verify the structure of a software unit by creating a sufficient number of test cases to ensure that every line of code in the software unit and every branch statement (true/false) is executed at least once.

3.1.116**wireless communication**

Transfer of information between two or more points that are not connected by an electrical conductor.

3.2 Abbreviations

For the purposes of this document, the following abbreviations and acronyms apply.

ACR	Accumulator Capacity Requirement
ANSI	American National Standards Institute
ASTM	American Society of Testing and Materials
AWS	American Welding Society
BOP	blowout preventer
BSR	blind shear ram
CCU	central control unit
CSR	casing shear ram
DMAS	deadman autoshear
EDS	emergency disconnect sequence
ESD	emergency shutdown
FAT	factory acceptance test
FMEA	failure modes and effects analysis
FVR	functional volume requirement
HPU	hydraulic power unit
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
KSC	Kennedy space center

LMRP	lower marine riser package
MUX	multiplex system
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination (e.g., ultrasonic, radiographic, dye penetrant, etc.)
NIST	National Institute of Standards and Technology
OEM	original equipment manufacturer
P and ID	piping and instrumentation diagram
PQR	procedure qualification record
ROV	remotely operated vehicle
RWP	rated working pressure
UPS	uninterrupted power supply
VE	volumetric efficiency
VEp	pressure-limited volumetric efficiency
VEv	volume-limited volumetric efficiency
WPS	welding procedure specification

4 Control System Descriptions

4.1 Control Systems for Surface BOP Stacks

Control systems for surface BOP stacks are typically return-to-reservoir hydraulic control systems consisting of a reservoir for storing hydraulic fluid, pump equipment for pressurizing the hydraulic fluid, accumulator banks for storing power fluid and manifolds, piping, and control valves for transmission of control fluid to the BOP stack functions and instrumentation for system control.

4.2 Discrete Hydraulic Control Systems for Subsea BOP Stacks

Remote control of a seafloor BOP stack requires specialized equipment. In addition to the equipment required for surface-mounted BOP stacks, discrete hydraulic subsea control systems use umbilical hose bundles for transmission of hydraulic pilot signals subsea. Also used are dual subsea control pods mounted on the LMRP and housing pilot operated control valves for directing power fluid to the BOP stack functions. Spent water-based hydraulic fluid is usually vented subsea. Hose reels are used for storage and deployment of the umbilical hose bundles. The use of dual subsea pods and umbilicals affords redundancy.

4.3 Electro-hydraulic/Multiplex (MUX) Control Systems for Subsea BOP Stacks

For deepwater operations, transmission subsea of electric/optical (rather than hydraulic) signals affords short response times. Electro-hydraulic systems employ multi-conductor cables, having a pair of wires dedicated to each function to operate subsea solenoid valves which send hydraulic pilot signals to the control valves that operate the

BOP stack functions. Multiplex control (MUX) systems employ serialized communications with multiple commands being transmitted over individual conductor wires or fibers. Electronic/optical data processing and transmission are used to provide the security of codifying and confirming functional command signals so that a stray signal, cross talk or a short circuit should not execute a function.

4.4 Control Systems for Diverter Equipment

Direct hydraulic controls are commonly used for operation of the surface mounted diverter unit. Associated valves may be hydraulically or pneumatically operated.

4.5 Auxiliary Equipment Control Systems

For floating drilling operations, various auxiliary functions such as the telescopic joint packer, latch/pin connection, riser annulus gas control equipment, etc., can be operated by the control system. These auxiliary equipment controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and requirements for similar equipment.

4.6 Emergency Control Systems

Emergency control systems are designed to automatically activate when certain conditions are met; two emergency control systems are autoshear and deadman.

4.7 Secondary Control Systems

When the main control system is inaccessible or non-functional, a secondary control system may be used to operate selected well control, disconnect, or recovery functions, or a combination thereof. These include acoustic control systems and ROV operated control systems.

4.8 Emergency Disconnect Sequenced Systems (EDS)

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. An EDS is activated by rig personnel when specific emergency conditions occur on a floating drilling vessel. These controls, though not specifically described herein, shall be subject to the relevant specifications provided herein and the requirements for similar equipment.

5 Control System Design Requirements

5.1 General

Well control systems and equipment identified in Section 4 designed or supplied by control system manufacturers, or both, shall meet or exceed these specifications.

5.2 Design Review

Prior to manufacturing the equipment or issuing equipment from stock to fill the sales order requirements, the manufacturer's responsible engineering authority shall verify that the design satisfies all requirements in accordance with these specifications. Design verification and validation shall follow the requirements specified in API Q1.

5.3 Operational Conditions

5.3.1 The purchaser shall provide all necessary information for the BOP stack and other equipment to be controlled to ensure that the control system design meets the requirements of this specification.

5.3.2 The following shall be defined for all equipment supplied and be documented as part of the deliverables to the purchaser:

- a) Hydraulic capacity requirements.
- b) System rated working pressure(s).
- c) Environmental conditions—the design of each sub-system or assembly capable of being located in different environments shall account for the following parameters and be documented as part of the deliverables to the purchaser.
 - 1) Temperature ratings shall be established that provide for operation within the ambient temperatures anticipated or the operational environment must be controlled within the temperature ratings of the equipment.
 - 2) Enclosure ratings—ingress protection of enclosures shall be rated for the environment in which they are installed in accordance with IEC 60529 or equivalent national or international standard.
 - 3) Corrosive environment—subsea or splash zone equipment that require special materials or cathodic protection shall be defined.
 - 4) Humidity ratings shall be established that provide for operation within the anticipated environmental conditions or the operational environment must be controlled to ensure environmental conditions are maintained within the ratings of the equipment.
 - 5) Hazardous area classifications—equipment shall be designed in accordance with a national or international standard. (Reference NEC 500, NEC 505, IEC 60079).

5.4 Design Data Documentation Requirements

5.4.1 Graphic symbols for fluid power and electrical diagrams shall be in accordance with ISO 1219 or IEC 60617 (or equivalent international or national standard) and documented with a symbols library. The standard being followed shall be clearly identified. If a graphic symbol does not exist, the symbol must be clearly recognized within the library as to its functionality. The manufacturer shall provide this legend to the end user on all hydraulic, pneumatic, and electrical drawings that include symbology.

NOTE This legend can be provided on each drawing that includes symbology or a separate document that is referenced on each drawing.

5.4.2 Design data documentation shall be retained by the manufacturer for each system design type for a minimum of 10 years after delivery of the last unit of the subject design.

5.4.3 The design data documentation shall include a table of contents.

5.4.4 Design data deliverable to the purchaser shall include the following.

- a) utilities consumption list;
- b) general arrangement drawings, factory acceptance test data, sizing calculations, and FMEA to document conformance to standards and specifications;
- c) list of applicable standards and specifications.

5.5 Reservoirs and Reservoir Sizing—General

5.5.1 Reservoirs shall be designed to accommodate the fluids to be stored.

5.5.2 Cleanout ports/hatches shall be provided for each reservoir to facilitate cleaning. Cleanout ports shall be minimum 4-in. diameter. At least one inspection port shall be located above the normal maximum fluid level of the reservoir.

5.5.3 To prevent over pressurization, each reservoir shall have air vents that have air flow capacity in excess of the incoming fluid flow capacity (including flow from accumulators into the mixed fluid reservoir). These vents shall not lend themselves to being mechanically sealed.

5.5.4 Accumulator capacity that is vented back to reservoir during normal operation of the system shall be included in reservoir sizing requirement.

5.5.5 Hydraulic fluid reservoirs shall be cleaned and flushed of all weld slag, machine cuttings, sand and any other contaminants before fluid is introduced.

5.6 Return-to-Reservoir Hydraulic Reservoirs

5.6.1 The hydraulic fluid reservoir usable capacity shall be at least twice the stored hydraulic fluid capacity of the accumulator system(s). Fluid located below the level required for proper pump operation is not considered part of usable capacity. The reservoir design shall ensure that fluid levels can be maintained below any inspection ports that are normally accessed during operations and still meet the usable capacity requirements.

5.6.2 Return-to-reservoir hydraulic systems do not require an automatic mixing system.

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

5.6.4 A pump shutoff level and (low, low-level) alarm may be provided to shut down the pumps before cavitation can occur. If a pump shutoff is installed, there shall be a manual override to operate the pump(s).

5.7 Vent-to-Environment Hydraulic Reservoirs

5.7.1 Main Mixed Fluid Reservoir

5.7.1.1 The control system fluid reservoir usable capacity shall be at least equal to the maximum possible total surface accumulator stored hydraulic fluid volume and have sufficient additional volume in the reservoir to permit draining the largest bank of accumulators back into the reservoir without overflow.

NOTE Fluid located below the level required for proper pump operation is not considered part of usable capacity.

5.7.1.2 The reservoir design shall ensure that fluid levels can be maintained below any inspection ports that are normally accessed during operations and still meet the usable capacity requirements. An automatic hydraulic mixing system is required for this type of system.

5.7.2 Control Fluid Concentrate Reservoir

The control fluid concentrate reservoir shall be sized using the maximum anticipated ratio for mixing the control system's hydraulic fluid. It shall have sufficient capacity to contain at least 10 times the concentrate necessary to mix the power fluid volume of the main accumulator system.

5.7.3 Ethylene Glycol Reservoir

The ethylene glycol reservoir, if installed, shall be sized using the maximum anticipated ethylene glycol/water ratio for the minimum anticipated ambient temperature to which the control fluid is to be exposed. The reservoir shall have sufficient capacity to contain enough ethylene glycol to mix at least 1.5 times the power fluid volume of the main accumulator system.

5.8 Hydraulic Fluid Mixing System

5.8.1 The hydraulic fluid mixing system shall be designed for automatic operation.

5.8.2 The system shall automatically stop (or finish the current batch) when the mixed fluid reaches the designated shut-off level for the reservoir.

5.8.3 The mixing system shall automatically restart before the fluid level decreases not more than 10 % below the shut-off level.

5.8.4 The mixing system shall be capable of mixing the fluids at a mixture ratio suitable to combat freezing at anticipated ambient temperature and supply an output flow rate at least equal to the combined discharge flow rate of the pump systems.

5.8.5 The automatic mixing system should be adjustable by the user over the ranges recommended by the manufacturer of the water-soluble lubricant additive including proper proportioning of ethylene glycol.

5.8.6 A means to override the automatic mixing system shall be provided.

5.9 Hydraulic Fluid Filtration

5.9.1 The hydraulic fluid shall be filtered to ensure proper operation in accordance with the control system manufacturer's requirements. The main system hydraulic power fluid supply shall use a dual filter parallel arrangement with isolation valves (to facilitate online maintenance).

5.9.2 Filters may permit manual or automatic bypassing of clogged elements rather than interrupting system operation. If automatic bypass is utilized, it shall include a bypassing indicator.

5.9.3 Filter housings should be mounted in an accessible location to facilitate maintenance.

5.10 Close, Shear and Seal Operation

5.10.1 Close and seal is the process to close a ram BOP with the operator pressure required to seal the wellbore (MOPFLPS) and lock the rams.

NOTE MOPFLPS is not a single number, as environmental conditions can include elevated wellbore pressures at different temperatures.

5.10.2 Shear and seal is the process to shear the drill pipe, seal the wellbore, and lock the sealing rams.

Depending on the state of operations, there can be elevated wellbore pressure which affects the operating pressure required; the functional requirements for this process shall be dependent on the equipment used.

- a) For a BOP stack that uses a blind shear ram, shear and seal is defined as closing the blind shear rams with the operator pressure required to shear the drill pipe used on the rig that has the highest shear pressure, seal the wellbore, and lock the blind shear rams.

- b) For a BOP stack that uses casing shear rams and blind shear rams to shear and seal, shear and seal is defined as closing the casing shear rams with the operator pressure required to shear the drill pipe used on the rig that has the highest shear pressure, closing the blind shear rams on open hole with the operator pressure required to seal the wellbore, and lock the blind shear rams.
- c) For a BOP stack that has additional functions to shear and seal the wellbore, those functions shall be included in the shear and seal requirement.

5.11 FMEA and Validation Testing

5.11.1 General

A FMEA shall be provided for each control system design in accordance with IEC 60812 or equivalent national or international standards (including emergency and secondary systems) down to the lowest maintainable subassembly. The FMEA is used to identify and control risk associated with the functionality of the control system. The FMEA shall identify the techniques, tools and their application for risk identification, assessment, and mitigation.

NOTE The FMEA can include consideration of severity, detection methods, and probability of occurrence.

5.11.2 BOP Functionality

The FMEA shall include local, system, and global effects. The global effects shall include the loss of BOP system functionality, as defined in API 53 and the following.

- a) For surface stacks:
 - 1) close and seal on the drill pipe, tubing, casing, or liner and allow circulation;
 - 2) close and seal on open hole and allow volumetric well control operations;
 - 3) strip the drill string;
 - 4) shear the drill pipe or tubing and seal the wellbore (for surface stacks with shear rams).
- b) For subsea stacks:
 - 1) close and seal on the drill pipe, tubing, and on casing or liner and allow circulation;
 - 2) close and seal on open hole and allow volumetric well control operations;
 - 3) strip the drill string;
 - 4) hang-off the drill pipe on a ram BOP and control the wellbore;
 - 5) shear the drill pipe or tubing and seal the wellbore;
 - 6) disconnect the riser from the BOP stack;
 - 7) circulate the well after drill pipe disconnect;
 - 8) circulate across the BOP stack to remove trapped gas;
 - 9) Deadman autoshear (DMAS);

10) EDS (if applicable).

The subsea control system shall not include a subsea component single-point failure that results in the inability to operate the BOP system; with the exception of the shuttle valve and associated piping that connects directly to the BOP function port.

5.11.3 Test Requirements

5.11.3.1 A validation test or analysis shall be performed for each control system design.

NOTE A control system design is a primary, secondary or emergency control system of a new design or a redesign using components not previously proven.

5.11.3.2 Testing or analysis shall ensure the following:

- a) The results for each non-destructive local, system and global failure mode that have identifiable detection methods (i.e. alarms) operate as specified in the FMEA. The failure modes that warrant actual testing shall be ones that have the potential of causing the control system to fail to perform as required by this specification.
- b) The functionality meets requirements set forth in this specification.
- c) The capability to meet closing times.
- d) The equipment is fit for purpose and suitable for the environment to which it is exposed during transportation, handling, installation and operation.
- e) For systems that are to be used subsea, calculated volumes for stack mounted accumulators (at the rig design water depth) shall be applied to a bank of surface accumulators to simulate subsea accumulator delivered volumes. The pressure drop in riser mounted rigid conduits shall be calculated for the maximum flow required (at maximum design depth), and a hose with equivalent pressure drop may be used for the in-plant tests.
- f) If an analysis is used as an alternative to testing, the manufacturer shall provide information based on facts that can be proven through analysis, measurement, observation, and other such means of research that the equipment performs as specified.

5.12 Equipment Design Specifications

5.12.1 Control Circuitry

Surface and subsea control function circuitry shall be designed such that a leak or failure in one circuit shall not cause the unintended operation of another function.

5.12.2 Loss of Rig Power

Loss of any rig power services (electricity, compressed air, etc.) shall not immediately cause the loss of control of the well control equipment; see 5.16.2.

5.12.3 Backup Power

Control stations shall have adequate backup power available as specified in this document; see 5.17.2.

5.12.4 Subsequent Operation on Power Loss

The restoration of power to the control system after a power loss shall not result in the automatic operation of a control system function.

5.12.5 Conformance to Specifications

The surface and subsea control system manufacturer's design and component selection process shall ensure that commodity items, sub-vendor materials, and the manufacturer's own equipment meet or exceed applicable industry standards and these specifications.

5.12.6 Purchaser-supplied Information

The purchaser shall provide complete description of, and functional specification for:

- a) the equipment to be operated,
- b) service conditions,
- c) any application details necessary for the manufacturer to design and build a control system that complies with these specifications.

5.13 Main Pumping System

5.13.1 General

The main pumping system provides power fluid for the main control system hydraulic functions. The main pumping unit is used to provide fluid power for the BOP control system, and may be used to provide fluid power to dedicated accumulator systems.

5.13.2 Power Supply Requirements

The main pumping unit shall be comprised of a minimum of two pump systems with at least two independent power systems.

NOTE 1 A pump system consists of one or more pumps.

NOTE 2 An independent power system is a source of power that is not impaired by any fault which disables the power to the other pump system(s).

NOTE 3 Examples of independent power supplies include the following:

- one pump may be powered from the emergency bus on an all-electric power rig;
- on electric drive rigs, separate electric motors and motor controllers fed from separate buses or from buses that can be isolated by means of a bus tie circuit breaker constitute independent power supplies;
- on rigs utilizing compressed air, the compressor is powered by a different prime mover, or the electric motors for compressors is powered by a system which is independent from the primary electrical supply for the pumps, a separate bus, or if there is sufficient stored air to meet requirements in 5.13.3.

5.13.3 Output Requirements

The main pumping unit shall be comprised of the following.

- The cumulative output capacity of the pump systems shall be sufficient to charge the main accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 15 minutes.
- With the loss of one pump system or one power system, the remaining pump system(s) shall have the capacity to charge the main accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 30 minutes.

5.13.4 Pump Isolation Requirements

A supply fluid isolation valve and a discharge valve shall be provided on each pump, these valves shall not affect the operation of other pump(s).

5.13.5 Air Pumps

Air pumps, if used, shall be capable of charging the accumulators to 98 % to 100 % of the system RWP with 75 psi (0.52 MPa) air pressure supply.

5.13.6 Over-pressurization

Each pump system shall be protected from over-pressurization by a minimum of two devices designed to limit the pump discharge pressure as follows:

- a) One device shall ensure that the pump discharge pressure does not exceed the system RWP.
- b) The second device, normally a relief valve, shall be set to relieve at not more than 10 % above the system RWP. The relief valve(s) and vent piping shall accommodate the maximum pumping capacity at not more than 133 % of system RWP. Verification shall be provided by either design calculation or testing.
- c) Devices used to prevent pump over-pressurization shall be installed directly in the control system supply line to the accumulators and shall not have isolation valves or any other means that could defeat their intended purpose.
- d) Relief devices on main hydraulic surface supplies shall be automatically resetting. Rupture discs or non-resetting relief valves, or both, can cause the complete loss of pressure control and shall not be used.

5.13.7 Primary Pumps

Primary pumps shall automatically start before system pressure has decreased to 90 % of the system RWP, and automatically stop between 98 % and 100 % of the system RWP.

5.13.8 Secondary Pumps

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

NOTE This provides operation similar to the primary pumps, except that the set point to start the secondary pump can be adjusted slightly lower so that both pump systems do not start simultaneously.

5.13.9 Manual Operation

Manual operation of each pump system shall be through the use of a switch or button that is spring reset to the 'OFF' state.

EXAMPLE The pump stops if the manual operation button or switch is let go.

5.13.10 Low-level Shutdown

If a low-level shutdown is installed in any reservoir to shut down the pumps before cavitation can occur, an audible and visual alarm shall indicate the condition at the main system and at least two remote locations.

5.14 Pump Systems for Dedicated Accumulator Systems

5.14.1 General

If the main pumping system is NOT used to provide fluid power to dedicated accumulator systems, the pump systems for dedicated accumulator systems shall be comprised of a minimum of two pump systems with at least two independent power systems.

NOTE 1 A pump system consists of one or more pumps.

NOTE 2 An independent power system is a source of power that is not impaired by any fault which disables the power to the other pump system(s).

NOTE 3 Compressed air is not considered an independent power supply unless the compressor is powered by a different prime mover, or the electric motors for compressors is powered by a system which is independent from the primary electrical supply for the pumps.

5.14.2 Output Capacity

The cumulative output capacity of the pump systems shall be sufficient to charge the dedicated accumulator system from precharge pressure to 98 % and 100 % of the system RWP within 60 minutes. With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the dedicated accumulator system from precharge pressure to 98 % to 100 % of the system RWP within 120 minutes.

5.14.3 Primary Pump

The primary pump system shall automatically start before system pressure has decreased to 95 % of the system RWP and automatically stop between 98 % and 100 % of the RWP.

5.14.4 Secondary Pump

The secondary pump system shall automatically start before system pressure has decreased to 90 % of the system RWP and automatically stop between 95 % and 100 % of the system RWP.

5.14.5 Pump Isolation Requirements

A supply fluid isolation valve and a discharge valve shall be provided on each pump, these valves shall not affect the operation of other pump(s).

5.14.6 Air Pump

Air pumps, if used, shall be capable of charging the accumulators to 98 % to 100 % of the system RWP with 75 psi (0.52 MPa) air pressure supply.

5.14.7 Over-pressurization

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

- a) One device shall ensure that the pump discharge pressure does not exceed the system RWP.
- b) The second device, normally a relief valve, shall be set to relieve at not more than 10 % above the system RWP. The relief valve(s) and vent piping shall accommodate the maximum pumping capacity at not more than 133 % of system RWP. Verification shall be provided by either design calculation or testing.
- c) Devices used to prevent pump over-pressurization shall be installed directly in the control system supply line to the accumulators and shall not have isolation valves or any other means that could defeat their intended purpose.
- d) Relief devices shall be automatically resetting; rupture discs or non-resetting relief valves, or both, can cause the complete loss of pressure control and shall not be used.

5.14.8 Manual Operation

Manual operation of each pump system shall be through the use of a switch or button that is spring reset to the 'OFF' state.

5.14.9 Monitoring

5.14.9.1 The dedicated accumulator pressure shall be capable of being monitored by the main control system and at least two control station locations inclusive of the driller's station.

5.14.9.2 Dedicated subsea accumulators used with a discrete hydraulic control system do not require monitoring by the main control system.

5.15 BOP Control Valves, Fittings, Lines and Manifolds

5.15.1 Pressure Rating

All valves, fittings, piping, flexible lines, hoses and other pressure retaining components such as pressure switches, transducers, transmitters, etc., shall have a RWP at least equal to the RWP of the circuit in which it is installed.

5.15.2 Piping Systems

Pipe and tubing shall conform to specifications of ASME B31.3 or an equivalent recognized national or international standard.

5.15.3 Accumulator Bottles and Manifolds

5.15.3.1 Accumulators shall meet design requirements of and be documented in accordance with applicable normative references listed in 14.2.3 and 14.8.4.

5.15.3.2 The main accumulator system shall be designed such that the loss of an individual accumulator or bank does not result in more than 25 % loss of the total accumulator system capacity.

5.15.3.3 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.

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

5.15.3.5 The precharge pressure for bladder type accumulators should be greater than 25 % of the system hydraulic pressure, to reduce the risk of damage to the bladder. Absolute pressures should be used for determining minimum precharge pressure when bladder type accumulators are used subsea (i.e. precharge pressure in psia should be greater than 25 % of system hydraulic pressure in psia).

5.15.3.6 Dedicated accumulator systems may be dedicated to a control system (such as the diverter control system), to an emergency system (such as the DMAS), or to a specific function or functions (such as high-pressure shear rams close, which can be operated by different control systems). The dedicated accumulators shall be sized based on the highest capacity requirement.

5.15.3.7 A non-oxidizing (inert) gas with low flammability, such as nitrogen or helium, shall be used for precharging accumulators. Compressed air or oxygen shall not be used to precharge accumulators. If helium is used, special requirements for containment of helium gas shall be addressed. Among these requirements are leakage past seals, permeability through elastomers, and solubility of gas in operating fluid.

5.15.3.8 The precharge pressure in the system accumulators serves to propel the hydraulic fluid stored in the accumulators for operation of the system functions. The amount of precharge pressure is a variable depending on specific operating requirements of the equipment to be operated and the operating environment. Operation manuals shall state any requirements for precharge pressures required based on design. The temperature conditions (operating range) shall be specified for surface installations.

5.15.3.9 The OEM shall provide to the buyer the minimum operating pressure, ACR, and the accumulator sizing method to be used for calculating volume-sized accumulator precharge pressures for operation.

5.15.4 Hydraulic Pressure Control Circuits

5.15.4.1 The control system shall be capable of providing the required shear pressure. The required shear pressure shall be provided by the purchaser.

5.15.4.2 An isolation valve with nominal bore size at least equal to the control manifold(s) supply piping size shall be provided for supply of control fluid from an alternate source. This valve shall be supplied with a blind flange (or plug) of the correct size and RWP.

5.15.4.3 A minimum of two independent hydraulic pressure control circuits shall be provided (typically, manifold and annular BOP regulated pressure circuits).

5.15.5 Pressure Control Manifold(s)

5.15.5.1 The hydraulic control manifold is the assemblage of hydraulic control valves, regulators, gauges and related equipment from which the system functions are directly operated. It allows regulation of the power fluid pressure to within the ratings specified by the BOP manufacturer. The hydraulic control manifold provides direct pressure reading of the various supply and regulated pressures.

5.15.5.2 The circuit(s) shall be provided with a regulator bypass valve or other means to increase the pressure of the circuit to the maximum RWP of the functions being controlled. The circuit shall be designed so that it cannot exceed the RWP of the functions being controlled. Functions on a regulated circuit shall be grouped such that they are not adversely affected by changes in the regulated pressure.

5.15.5.3 The pressure regulators shall provide regulated pressures through the required range of the designated function(s). The valves and regulators shall be sized to supply the volume required to operate each function within its specified response time.

5.15.5.4 The annular BOP Control manifold shall include a dedicated pressure regulator to reduce upstream manifold pressure to the power fluid pressure level that meets the BOP manufacturer's recommendations. The

annular BOP Control regulator shall respond to pressure changes on the downstream side with sensitivity sufficient to maintain the set pressure ± 150 psi. The annular BOP pressure regulator shall be remotely controllable.

5.15.6 Hydraulic Control Manifold Valves

The valves shall be installed such that placing the control valve handle on the right side (while facing the valve) closes the BOP or choke or kill valve, the left position shall open the BOP or choke or kill valve.

NOTE The center position of the control valve is called the “block” or “vent” position. In the center position, power fluid supply is shut off at the control valve. The other function ports on the four-way valve may be either vented or blocked depending on the valve selected for the application.

The hydraulic circuit schematics shall clearly indicate the center position control valve port assignments for the particular control system.

Valves and gauges shall be clearly labeled as to function and position.

5.15.7 Relief Valves

5.15.7.1 Relief valves shall be separately tested and adjusted using a low-flow rate, dead-weight tester (or comparable method).

5.15.7.2 A certificate of the relief valve setting and operation shall be provided indicating the set point and the pressure at which the relief valve reseats

5.15.7.3 Relief valves shall reseal within 25 % of the set pressure.

5.15.7.4 Relief valves shall additionally be tested to determine the maximum flow rate through the relief valve without exceeding 115 % of the relief valve’s set pressure.

5.16 Remote Operation

5.16.1 Control Stations—General

5.16.1.1 There shall be at least two control station locations.

5.16.1.2 One control station shall be designed for installation in an area accessible by the drill crew which can include the drill floor, the driller’s cabin, or area specified by the purchaser. For onshore installations, either control station may be the hydraulic manifold.

5.16.1.3 For offshore installations there shall be at least two control station locations in addition to the hydraulic manifold (if installed).

5.16.1.4 Each control station location shall have the following capability:

- a) Control the BOP stack functions.
- b) Control the diverter functions (if installed).

c) Control the pressure regulation of functions that require variable control pressure. Examples include:

- annular BOPs,
- ram BOPs,
- diverter packer,
- connectors.

d) Monitor all system pressures.

e) Monitor status of all alarms.

5.16.1.5 For subsea applications, the pilot pressure for remotely adjustable regulators shall be adjustable on both the online and offline pod.

5.16.2 Loss of Power

5.16.2.1 The loss of rig power services (electricity, compressed air, etc.) shall not immediately cause the loss of control of the well control equipment.

5.16.2.2 An isolated pilot supply (pneumatic or hydraulic) shall be provided for the remote operation of surface manifold-mounted control valves. Loss of pilot supply shall not affect the manual operation of the control valves.

5.16.2.3 The remote control system shall permit operation of the surface function control valves at least two times after the loss of rig air or electric power (excluding regulator controls), or both.

5.16.3 Layout Requirements

5.16.3.1 Visual position indication shall be installed on remote control stations for all function positions that are operable from the remote control station. Control station lamps (or other means of visual indication) that are used to indicate function status shall track the position of the hydraulic control valves. Red, amber, and green shall be used as standard colors for control station indicator lights (or displays). Green shall indicate that the function is in its normal drilling position.

Red shall indicate that the function is in an abnormal position. Amber shall indicate that the function is in a “block” or “vent” position. On functions that have three or more positions, red or green shall be on whenever the “block” or “vent” (amber) indication is on and thereby indicate the function’s last selected position.

NOTE Other indicator colors may be used for information display on functions such as selection of yellow or blue for subsea control pods.

5.16.3.2 The remote control panels shall be designed so that the last position of a blocked or vented function shall not be displayed when restoration from an event causing the panel to go offline or otherwise be compromised could result in an incorrect indication.

5.16.3.3 Control station functionality and external control functionality, excluding the regulator controls, shall require a two-handed operation (e.g., the use of an “ENABLE” or “PUSH and HOLD” in addition to the function).

5.16.3.4 Physical arrangement of the control station shall be as a graphic representation of the flow path of the BOP stack or diverter, or both. The placement of the function for button and screen arrangements and visual indications shall be laid out such that the function on the right-hand side closes the BOP or choke or kill valve, and the function on the left-hand side shall open the BOP or choke or kill valve.

5.16.3.5 Each control station shall be capable of displaying the operator positions and pressure read backs for the entire BOP stack and diverter if both the BOP and diverter can be in use simultaneously.

5.16.3.6 Control station panel control devices shall be physically spaced to prevent unintended operations.

5.16.4 Pressure Measurement

5.16.4.1 Mechanical Analog Pressure Measurement

Mechanical analog pressure measurement devices shall be selected in accordance with the following:

- a) maximum operating pressure is less than or equal to 75 % of full scale;
- b) minimum operating pressure (when used as a test gauge) is greater than or equal to 25 % of full scale;
- c) normal operating pressure (when used as a control system gauge) is between 25 % and 75 % of full scale (it is acceptable for a control system gauge to measure below 25 % of full scale when the normal operating pressure range exceeds 50 % of full scale);
- d) full scale is displayed over a minimum span of 120°;
- e) meets requirements of ASME B40.100 Grade C or better.

5.16.4.2 Electronic Pressure Measurement

Electronic pressure measurement shall include the following:

- a) accuracy within ± 2.5 % of the circuit(s) operational range;
- b) a maximum display range less than or equal to 133 % of maximum operating pressure for scaled displays. (numeric readouts are not subject to this restriction);
- c) resolution within 2.5 % of full scale.

5.16.4.3 Units

5.16.4.3.1 Pressure readings shall be displayed in psi; additional units of measure are optional.

5.16.4.3.2 Units of measurement shall be consistent throughout the control system.

5.16.5 Alarms

5.16.5.1 The alarm circuits or software, or both, should be designed so the frequency of false indication(s) is eliminated or reduced to a minimum level without compromising the ability of the system to provide indication of an abnormal condition to the equipment operators.

5.16.5.2 The normal operation of the system should not activate an alarm.

5.16.5.3 The following summary alarms shall have local visual indication with an audible alarm when the listed event(s) condition is met:

- a) accumulator pressure LOW:

- 1) main accumulator pressure LOW (surface, discrete hydraulic, MUX);
- 2) dedicated shear accumulator pressure LOW (surface, MUX);
- 3) diverter accumulator pressure LOW (surface, discrete hydraulic, MUX);
- b) pod supply pressure LOW (MUX);
- c) pod pilot supply pressure LOW (MUX);
- d) control manifold pressure LOW (surface, discrete hydraulic, MUX):
 - 1) BOP manifold (control of ram BOPs, choke/kill outlet valves);
 - 2) wellhead connector manifold;
 - 3) LMRP connector manifold;
 - 4) dedicated shear manifold.
- e) control manifold pilot pressure LOW (surface, discrete hydraulic, MUX):
 - 1) BOP manifold (control of ram BOPs, choke/kill outlet valves);
 - 2) wellhead connector manifold;
 - 3) LMRP connector manifold;
 - 4) dedicated shear manifold.
- f) rig air pressure LOW (surface, discrete hydraulic, MUX);
- g) control fluid level LOW (surface, discrete hydraulic, MUX);
- h) mix system FAILURE (discrete hydraulic, MUX):
 - 1) lubricant fluid level LOW;
 - 2) glycol level LOW (if applicable);
 - 3) rig water supply pressure (or level) LOW.
- i) primary power LOSS/standby power IN USE (surface, discrete hydraulic, MUX);
- j) pump system FAULT for electric-driven pump systems (surface, discrete hydraulic, MUX):
 - 1) pump system electric power LOSS;
 - 2) pump FAULT.
- k) air purge LOSS (surface, discrete hydraulic, MUX);
- l) control station communication FAULT (surface, discrete hydraulic, MUX);

- m) pod communication FAULT (MUX);
- n) slip joint packer AUTO SEQUENCED (discrete hydraulic, MUX);
- o) diverter FAULT (surface, discrete hydraulic, MUX);
 - 1) diverter manifold pressure LOW;
 - 2) diverter packer pressure LOW;
 - 3) flowline seal pressure LOW.

5.16.6 Readout Requirements

The control station shall be equipped for readout of the following (where equipment/system is installed):

- a) main accumulator pressure (surface, discrete hydraulic, MUX);
- b) diverter accumulator pressure (surface, discrete hydraulic, MUX);
- c) dedicated shear accumulator pressure (surface, MUX);
- d) conduit pressure (discrete hydraulic, MUX);
- e) hotline supply pressure (MUX);
- f) pod supply pressure (MUX);
- g) pod pilot supply pressure (MUX);
- h) control unit manifold pressure (surface, discrete hydraulic);
- i) control unit pilot pressure (surface, discrete hydraulic);
- j) regulator readback pressures (surface, MUX);
- k) regulator pilot pressures (surface, discrete hydraulic, MUX);
- l) rig air supply pressure (surface, discrete hydraulic, MUX);
- m) pump running indication (surface, discrete hydraulic, MUX);
- n) resettable surface flow meter (offshore surface, discrete hydraulic, MUX);
- o) resettable subsea flow meters (MUX);

5.16.7 Safety Requirements

5.16.7.1 A safety cover or other means (e.g., pop-up controls, mechanical restraint) that does not obstruct visibility of function status, shall be installed to avoid unintended operation of critical functions (where installed) including:

- a) connector(s) (LMRP, wellhead, choke & kill) retract / unlock;
- b) shear ram(s) close;

- c) emergency disconnect sequence activate;
- d) deadman/autoshear arm;
- e) deadman/autoshear disarm;
- f) pod stabs retract / unlock;
- g) diverter packer close.

5.16.7.2 To prevent operator complacency, noncritical functions shall not have the safety cover or other means described above.

5.16.7.3 Noncritical functions shall not have the safety cover or lock-out means described above, to prevent operator complacency.

5.16.7.4 Critical functions shall be clearly identified and have a different look to be easily distinguishable from non-critical functions. The LMRP connector unlatch function and wellhead connector unlatch function shall have a different look from other critical functions.

5.16.8 Failure or Disabling

The design shall be configured such that a failure of or disabling of one of the remote control station(s), remote control station components, or conductor/cable shall not:

- a) affect the operation of the other control station,
- b) result in erroneous indication, or
- c) cause another function to be unintentionally operated.

5.16.9 Touchscreens

5.16.9.1 Touchscreens, displays, keyboards, mouse, etc., may be used as a full control and monitoring station.

5.16.9.2 Subsea MUX installations utilizing touchscreens or displays for a control station shall include multiple touchscreens or displays with independent processors, each touchscreen or display shall be capable of providing the BOP stack and diverter function positions and pressure readbacks.

5.16.10 Cabling

Shipboard cabling design shall allow the cables from the control stations to the cable reels to be routed along separate paths to reduce the possibility of both cables being simultaneously damaged.

5.17 Electrical Equipment

5.17.1 General

5.17.1.1 Electrical displays (lamps, meters, etc.) shall be sufficiently luminous to be readily discernible in all conditions of ambient light in which the device can operate.

5.17.1.2 Electrical enclosures that include lamps that can change state during operations shall include lamp test capability to detect lamp failures. Power available lamps that are normally illuminated are excluded from this requirement.

5.17.1.3 No more than 130V RMS shall be connected to any component mounted on the face of an electrical enclosure that the user directly interfaces with to make routine adjustment.

NOTE This requirement does not apply to components that do not require routine adjustment, such as glanded cable entries or power switches/disconnects.

5.17.1.4 Electrical enclosures with inputs higher than 130V RMS shall:

- a) include a warning sign(s) mounted on the enclosure listing all voltages more than 130 V RMS,
- b) require tools to gain access.

5.17.1.5 Electrical equipment and enclosures exposed to the environment shall have defined ingress protection (IP) ratings suitable for the application.

5.17.1.6 Hydraulic lines or components containing hydraulic fluid shall not be mounted inside an electrical enclosure.

5.17.1.7 Electro-pneumatic devices mounted inside enclosures with vent lines shall be:

- a) vented to the outside of the enclosure,
- a) sized and connected such that the back pressure to other components does not cause any function to be unintentionally operated.

5.17.1.8 Wireless communication devices shall not be used for primary controls or end devices. Wireless communication devices may be used for maintenance, monitoring purposes, and secondary control (e.g. acoustic or additional control stations beyond the minimum stated in this specification). This requirement is not intended to prevent the use of pinless or non-contact connectors.

5.17.2 Electrical Power and Uninterruptable Power Supplies

5.17.2.1 The electrical conductors and electrical insulation shall not be used as load bearing components in the cable assembly.

5.17.2.2 Electrical power shall be supplied from one or more UPS system(s). Each UPS system shall have the backup battery capacity to operate the control system for a minimum of two hours (excluding the pump systems).

5.17.2.3 The electrical power supply to electrical equipment shall automatically switch to an alternate source of electric supply when primary power is interrupted (excluding the pump systems).

5.17.2.4 UPS batteries shall be a maintenance free design and sealed.

5.17.2.5 Subsea MUX control systems shall conform to the following:

- a) Include two independent UPS systems.
- b) Include two independent electrical umbilical cables. Each electrical umbilical cable shall contain all communications or power conductors, or both, required to control all the subsea functions through one pod. The severing, opening, or shorting of one cable assembly shall not disable the surface equipment and the pod connected to the other cable shall remain functional.
- c) Include an equipment design that permits cable routing from the electrical control units to the cable reels along separate paths to reduce the possibility of simultaneous failure of both cables.

- d) Be designed such that electrical control functions and electrical power required for running, landing and retrieving of the LMRP or the stack, or a combination thereof, can remain fully active.

5.17.3 Hazardous Area Electrical Equipment

5.17.3.1 General

5.17.3.1.1 The purchaser shall specify the hazardous area classification required for electrical equipment in accordance with API 500, API 505, IEC 60079-10-1 or equivalent recognized international standard.

5.17.3.1.2 Hazardous area electrical enclosures shall be certified by a national testing laboratory or notified body as suitable per the purchaser defined hazardous area classification.

5.17.3.1.3 Electrical assemblies and electrical equipment shall be suitable per the purchaser-defined hazardous area classification. The contractual requirements shall define the type of certification required, and the equipment manufacturer is to meet the contractual requirements and those of the authority having jurisdiction.

5.17.3.2 Air Purge Air Systems

5.17.3.2.1 Air purge systems shall only be used to increase the protection of a panel from Class 1 Division 2 to Class 1 Division 1 or from Zone 2 to Zone 1.

5.17.3.2.2 If an air purge system is used, the following apply:

- it shall be manufactured in accordance with NFPA 496, or IEC 60079-2 or another recognized international standard;
- a loss of air purge shall activate an alarm at the affected panel and at least two other control stations;
- a loss of purge shall not cause loss of functionality at any panel.

5.17.3.3 Subsystem Components

5.17.3.3.1 Subsystems (e.g. control stations, HPU, diverter control system, uninterruptable power supplies, hose reels) shall be factory acceptance tested for conformance with these specifications.

5.17.3.3.2 When a subsystem is integrated, the test procedures shall specify all parameters that can be measured in a partial test to verify conformance to the specifications. The test shall be considered in process, and documentation that specifies the final integrated test requirements shall be supplied to the purchaser.

5.18 Control System Software

5.18.1 General

The BOP control system software design and development process shall ensure:

- Design verification (e.g. test procedures) is related back to requirements providing evidence that design requirements have been met by the verification process.
- The process that is used for all software development activities whenever appropriate.
- The process is recorded with appropriate revision control providing historical archiving.

- Implementation that does not require unique or previous knowledge, or both (e.g. process is flexible to prevent continual process changes for each design and development).

5.18.2 Software Lifecycle Process

A software lifecycle process shall be documented and utilized for developing software or modifying software. The manufacturer may have multiple software lifecycle processes. Changes to the software lifecycle process shall be documented with revision controls. The software lifecycle process shall include the following:

- software functional specification (see 5.18.3)
- software design and development (see 5.18.4)
- software design validation and software design verification (see 5.18.5)
- software production and maintenance (see 5.18.6)

5.18.3 Software Functional Specification

5.18.3.1 A software functional specification shall be created that details the operational system requirements and includes the necessary information required to address the following (as applicable):

- a) user interface (e.g. Human Machine Interface—HMI);
- b) redundancy;
- c) timing:
 - system software boot up or initialization time;
 - software response time from operator initiation to acknowledgment displayed to operator;
 - recovery time for component/component processes to complete re-initialization;
 - hot standby failover time (if installed);
 - EDS timing;
 - alarm activation delays.
- d) sequencing;
- e) automation;
- f) interlocks;
- g) alarm management;
- h) error management;
- i) event logging and historical archiving;
- j) initialization;

- k) external interface(s);
- l) operator configuration capabilities.

5.18.3.2 The functional specifications shall include additional requirements from the user/purchaser and shall be documented.

5.18.3.3 A technical specification of software capabilities that satisfies the functional specification requirements shall be created and documented. The technical specification should be reviewed with the user/purchaser when applicable.

5.18.3.4 A software functional specification review shall be conducted and include personnel responsible for the system level (e.g. electrical, hydraulic, mechanical) design.

5.18.4 Software Design and Development

5.18.4.1 A software design review(s) shall be conducted and should include personnel responsible for the system level (e.g. electrical, hydraulic, mechanical) design. Software design reviews may be conducted at preliminary, critical and final design stages.

5.18.4.2 Software design architecture drawings shall be included in the design review that identify the hardware/software interfaces, dependencies, and processes to include the following:

- software topology;
- logic flow diagrams or function block specifications;
- external interfaces.

5.18.4.3 A software FMEA shall be performed down to the Software Unit level.

- The software FMEA shall include local, system and global effects. If the software is a modification of an existing design, a gap analysis of the software can be conducted in order to establish a new FMEA for that design.
- The global effects shall include:
 - loss of ability to secure the well;
 - loss of ability to disconnect from the well;
 - loss of ability to operate the diverter;
 - loss of sequencing, timing, or interlock capability;
 - loss of alarm capability;
 - loss of logging capability.

5.18.4.4 Software development shall use a documented coding standard. The coding standard can be internally or externally produced.

5.18.4.5 A software code review(s) shall be conducted and include other competent software personnel with ability to understand the software changes and its potential impacts.