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~~Specification for Subsea Wellhead and Tree Equipment~~

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Specification for Subsea Wellhead and Tree Equipment

Scope

This document provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads, and both vertical and horizontal subsea trees. It specifies the associated tooling necessary to handle, test, and install the equipment. It also specifies the areas of design, material, welding, quality control [including factory acceptance testing (FAT)], marking, storing, and shipping for individual equipment, subassemblies, and subsea tree assemblies.

The user/purchaser is responsible for ensuring that subsea equipment meets any additional requirements of governmental regulations for the country in which it is installed. This is outside the scope of this specification.

This specification is not applicable to the rework and repair of used equipment.

In situ testing is beyond the scope of this specification.

System integration test (SIT) is beyond the scope of this specification.

Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies, except that new editions may be used on issue and shall become mandatory upon the effective date specified by the publisher or 6 months from the date of the revision (where no effective date is specified).

API Specification 5B, *Threading, Gauging, and Inspection of Casing, Tubing, and Line Pipe Threads*

API Specification 5CT, *Casing and Tubing*

API Specification 5DP, *Drill Pipe*

API Specification 6A, *Specification for Wellhead and Tree Equipment*, 21st Edition

API Standard 6AV1, *Validation of Safety and Shutdown Valves for Sandy Service*

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

API Recommended Practice 17A, *Design and Operation of Subsea Production Systems—General Requirements and Recommendations*

API Standard 17F, *Standard for Subsea Production Control Systems*

API Standard 17G, *Design and Manufacture of Subsea Well Intervention Equipment*

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

API Recommended Practice 17P, *Recommended Practice for Subsea Structures and Manifolds*

API Recommended Practice 17R, *Recommended Practice for Flowline Connectors and Jumpers*

API Technical Report 17TR7, *Verification and Validation of Subsea Connectors*

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~~API Specification 20E, Alloy and Carbon Steel Bolting for Use in the Petroleum and Natural Gas Industries~~

~~API Specification 20F, Corrosion-resistant Bolting for Use in the Petroleum and Natural Gas Industries~~

~~ASME B16.11¹, Forged Fittings, Socket Welding and Threaded~~

~~ASME B31.3, Process Piping~~

~~ASME Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels, Division 2: Alternative Rules~~

~~ASME Boiler and Pressure Vessel Code, Section VIII: Rules for Construction of Pressure Vessels, Division 3: Alternative Rules for Construction of High Pressure Vessels~~

~~ASTM D1414², Standard Test Methods for Rubber O-Rings~~

~~DNV-RP-B401³, Cathodic Protection Design~~

~~ISO 8501-1⁴, Preparation of steel substrates before application of paints and related products—Visual assessment of surface cleanliness—Part 1: Rust grades and preparation grades of uncoated steel substrates and of steel substrates after overall removal of previous coatings~~

~~NACE MR0175/ISO 15156 (all parts)⁵, Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production~~

~~NACE No. 2/SSPC-SP 10, Joint Surface Preparation Standard: Near-White Metal Blast Cleaning~~

~~NACE SP0176, Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated with Petroleum Production~~

~~SAE AS4059⁶, Aerospace Fluid Power—Cleanliness Classification for Hydraulic Fluids~~

~~SAE J517, Hydraulic Hose~~

~~SAE J343, Test and Test Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies~~

~~Terms, Definitions, Acronyms, Abbreviations, and Symbols~~

~~Terms and Definitions~~

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

¹—American Society of Mechanical Engineers, Two Park Avenue, New York, New York 10016, www.asme.org.

²—ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

³—Det Norske Veritas, Veritasveien 1, 1363 Høvik, Norway, www.dnv.com.

⁴—International Organization for Standardization, Chemin de Blandonnet 8, CP 401 1214 Vernier, Geneva, Switzerland, www.iso.org.

⁵—Association for Materials Protection and Performance (formerly NACE International), 15835 Park Ten Place, Houston, Texas 77084, www.ampp.org.

⁶—SAE International, 400 Commonwealth Drive, Warrendale, Pennsylvania 15096, www.sae.org.

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~~3.1.1~~

~~actuator~~

~~Mechanism for the remote operation of a valve or choke.~~

~~3.1.2~~

~~annulus seal assembly~~

~~Mechanism that provides pressure isolation between each casing hanger and the wellhead (high pressure) housing.~~

~~3.1.3~~

~~backdriving~~

~~Unplanned movement.~~

~~3.1.4~~

~~bore protector~~

~~Device that protects internal bore surfaces during drilling or workover operations.~~

~~3.1.5~~

~~check valve~~

~~Device designed to prevent flow in one direction.~~

~~3.1.6~~

~~choke~~

~~Equipment used to restrict and control the flow of fluids and gas.~~

~~3.1.7~~

~~closure bolting~~

~~Threaded fasteners used to assemble wellbore pressure-containing parts or join end or outlet connections.~~

~~EXAMPLES — Flange bolting, bonnet bolting, end connection bolting, and clamp bolting.~~

~~3.1.8~~

~~component (or part)~~

~~Identifiable portion of an assembly that cannot be disassembled further and performs a defined function.~~

~~3.1.9~~

~~conductor (low-pressure) housing~~

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~~Top of the first casing string, which forms the basic foundation of the subsea wellhead and provides attachments for guidance structures.~~

3.1.10

~~corrosion cap~~

~~Cap placed over the wellhead to protect it from contamination by debris, marine growth or corrosion during temporary abandonment of the well.~~

3.1.11

~~corrosion-resistant alloy~~

~~GRA~~

~~Nonferrous-based alloy in which any one or the sum of the specified amount of the element titanium, nickel, cobalt, chromium, and molybdenum exceeds 50 % mass fraction.~~

~~NOTE—This definition is different from that in NACE MR0175/ISO 15156.~~

3.1.12

~~corrosion-resistant material~~

~~CRM~~

~~Ferrous or nonferrous alloy that is more corrosion resistant than low-alloy steels.~~

~~NOTE—This term includes CRAs, duplex, and stainless steels.~~

3.1.13

~~critical bolting~~

~~Threaded fasteners in the vertical load path from the subsea wellhead to the top connection of the subsea tree that are subjected to additional environmental loading resulting from the coupling of well control and well intervention equipment whose failure will result in the release of wellbore fluid to the environment.~~

3.1.14

~~crossover valve~~

~~Valve that, when opened, allows communication between the annulus and production tree paths, which are normally isolated.~~

3.1.15

~~depth rating~~

~~Maximum water depth at which equipment is designed to function.~~

3.1.16

~~downstream~~

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~~Direction of movement away from the reservoir.~~

~~3.1.17~~

~~event, extreme~~

~~Occurrence that produces operating conditions that exceed normal operating conditions and include the unavoidable but predictable load conditions due to environmental and operating scenarios; rated working pressure (RWP) or temperature is not exceeded during the event.~~

~~NOTE—Loading conditions for an extreme event can be specified by the user/purchaser in accordance with API 17G and API 17TR7.~~

~~3.1.18~~

~~event, normal~~

~~Occurrence that produces operating conditions that include all loads, individual and combined, as defined by operational criteria up to extreme conditions; RWP or temperature is not exceeded during the event.~~

~~3.1.19~~

~~event, survival~~

~~Occurrence that produces operating conditions that exceed extreme conditions and include the unplanned unavoidable, and unpredictable load conditions due to the environmental, operating, or any other scenarios; RWP or temperature is not exceeded during the event.~~

~~NOTE—Loading conditions for a survival event can be specified by the user/purchaser in accordance with API 17G and API 17TR7.~~

~~3.1.20~~

~~extension-sub~~

~~Sealing tubular member that provides tree-bore continuity between adjacent tree components.~~

~~3.1.21~~

~~fail-closed valve~~

~~Actuated valve designed to revert to the closed position when the actuator is de-energized.~~

~~3.1.22~~

~~fail-in-place valve~~

~~Actuated valve designed to remain in its current position when the actuator is de-energized.~~

~~3.1.23~~

~~fail-open valve~~

~~Actuated valve designed to revert to the open position when the actuator is de-energized.~~

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3.1.24

flowline

~~Any pipeline connecting to the subsea tree assembly outboard of the flowline connector or hub.~~

3.1.25

flowline connector support frame

~~Structural frame that receives and supports the flowline connector and transfers flowline loads back into the wellhead or seabed anchored structure.~~

3.1.26

flowline connector system

~~Equipment used to attach subsea pipelines and/or control umbilicals to a subsea tree.~~

~~EXAMPLE — Tree-mounted connection systems used to connect a subsea flowline directly to a subsea tree, connect a flowline end termination to the subsea tree through a jumper, connect a subsea tree to a manifold through a jumper, etc.~~

3.1.27

flow loop

~~Piping that connects the outlet(s) of the subsea tree to the subsea flowline connection and/or to other tree piping connections (crossover piping, etc.).~~

3.1.28

guide funnel

~~Tapered enlargement at the end of a guidance member to provide primary guidance over another guidance member.~~

3.1.29

guideline

~~Taut line from the seafloor to the surface for the purpose of guiding equipment to the seafloor structure.~~

3.1.30

high-pressure riser

~~Tubular member that extends the wellbore from the mudline wellhead or tubing head to a surface blowout preventer (BOP).~~

3.1.31

horizontal tree

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~~Tree that does not have a production master valve (PMV) in the vertical bore but in the horizontal outlet(s) to the side.~~

~~3.1.32~~

~~hyperbaric pressure~~

~~External pressure of ambient ocean environment.~~

~~3.1.33~~

~~inboard tree piping~~

~~Subsea tree piping upstream, relative to the wellhead, of the second actuated production valve.~~

~~3.1.34~~

~~intervention fixture~~

~~Device or feature permanently fitted to subsea well equipment to facilitate subsea intervention tasks.~~

~~NOTE—Examples include but are not limited to:~~

~~grasping intervention fixtures;~~

~~docking intervention fixtures;~~

~~landing intervention fixtures;~~

~~linear actuator intervention fixtures;~~

~~rotary actuator intervention fixtures;~~

~~fluid coupling intervention fixtures.~~

~~3.1.35~~

~~intervention system~~

~~Extension of the production and/or annulus bore(s) of a subsea well to a surface vessel using a riser.~~

~~NOTE 1 Intervention systems include but are not limited to:~~

~~open water intervention riser system (OWIRS);~~

~~through bore intervention riser system (TBIRS).~~

~~NOTE 2—See API 17G.~~

~~3.1.36~~

~~lifting bolting~~

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~~Bolting in the direct lifting load path that is loaded in tension that is not integral to the equipment being lifted, excluding commercial type lifting accessories and/or devices (e.g. eyebolts, shackles, etc.).~~

3.1.37

lifting pad-eye

~~Pad-eye, intended for lifting and suspending a designed load or packaged assembly.~~

3.1.38

loose connector

loose flange

~~Connector, as manufactured, that is not intended to be made integral with equipment conforming to this specification.~~

~~EXAMPLES — Blind, threaded, weld-neck, flanged, studded, or other end connectors (OECs).~~

3.1.39

lower workover riser package

LWRP

~~Unitized assembly that interfaces with the tree upper connection and allows sealing of the tree vertical bore(s).~~

3.1.40

manual valve (or choke)

manual operator

~~Valve (or choke), operated by a remotely operated vehicle (ROV), diver, or retrievable tool (remotely operated tool) intervention system.~~

3.1.41

mudline suspension system

~~Drilling system consisting of a series of housings used to support casing strings at the mudline, installed from a bottom-supported rig using a surface BOP.~~

3.1.42

outboard tree piping

~~Subsea tree piping that is downstream, relative to the wellhead, of the second, actuated production valve and upstream of the flowline connection.~~

3.1.43

performance requirement (level)

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~~Designation determined by the extent of testing successfully performed in accordance with minimum performance criteria identified by the specification.~~

3.1.44

~~permanent guidebase~~

~~Structure that sets alignment and orientation relative to the wellhead system and provides entry guidance for running equipment on or into the wellhead assembly.~~

3.1.45

~~pressure-containing part~~

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

~~EXAMPLES — Bodies, bonnets, one-piece stem, and the segment of multi-piece stems that passes through the pressure boundary.~~

3.1.46

~~pressure-controlling bolting~~

~~Bolting (other than critical bolting or closure bolting) whose failure would result in the loss of wellbore pressure-controlling functionality.~~

~~EXAMPLE — Hydraulic system bolting.~~

3.1.47

~~pressure-controlling part~~

~~Part intended to control or regulate the movement of pressurized retained fluids.~~

~~EXAMPLES — Valve-bore sealing mechanisms, choke trim, and hangers.~~

3.1.48

~~primary member~~

~~Bodies or structural members that support a load-bearing force or are in direct load path of lifting loads.~~

3.1.49

~~rated working pressure~~

~~RWP~~

~~Maximum internal pressure that the equipment is designed to contain and/or control.~~

3.1.50

~~re-entry hub~~

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~~Tree upper connection profile, which allows remote connection of a tree running tool, intervention system, or tree cap.~~

3.1.51

~~retained fluid~~

~~Fluid produced by or injected into a well.~~

3.1.52

~~reverse differential pressure~~

~~Condition during which differential pressure is applied to a choke valve in a direction opposite to the specified operating direction.~~

~~NOTE This can be in the operating or closed choke position.~~

3.1.53

~~running tool~~

~~Tool used to run, retrieve, position, or connect subsea equipment remotely from the surface.~~

~~EXAMPLES Tree running tools, tree cap running tools, flowline connector running tools, etc.~~

3.1.54

~~service condition~~

~~Classifications for pressure, temperature, and the various wellbore constituents and operating conditions for which the equipment is designed.~~

3.1.55

~~subsea BOP~~

~~Blowout preventer designed for use on subsea wellheads, tubing heads, or trees.~~

3.1.56

~~subsea casing hanger~~

~~Device that supports a casing string in the wellhead at the mudline.~~

3.1.57

~~subsea completion equipment~~

~~Specialized tree and wellhead equipment used to complete a well below the surface of a body of water.~~

3.1.58

~~subsea wellhead (high-pressure) housing~~

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~~Pressure-containing housing that provides a means for suspending and sealing the well casing strings.~~

~~3.1.59~~

~~subsea wireline/coiled tubing BOP~~

~~Subsea BOP that attaches to the top of a subsea tree to facilitate wireline or coiled tubing intervention.~~

~~3.1.60~~

~~substantive change~~

~~Change identified by the manufacturer that affects the performance of the product in the intended service.~~

~~3.1.61~~

~~surface BOP~~

~~Blowout preventer designed for use on a surface facility such as a fixed platform, jackup, or floating drilling vessel.~~

~~3.1.62~~

~~swivel flange~~

~~Flange assembly consisting of a central hub and a separate flange rim that is free to rotate about the hub.~~

~~NOTE Type 17SV swivel flanges can mate with standard API type 17SS and 6BX flanges of the same size and pressure rating.~~

~~3.1.63~~

~~tieback adapter~~

~~Device used to provide the interface between mudline suspension equipment and subsea completion equipment.~~

~~3.1.64~~

~~tree cap~~

~~Pressure-containing environmental barrier installed above production swab valve (PSV) in a vertical tree or tubing hanger in a horizontal tree.~~

~~3.1.65~~

~~tree connector~~

~~Mechanism to join and seal a subsea tree to a subsea wellhead or tubing head.~~

~~3.1.66~~

~~tree guide frame~~

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~~Structural framework that may be used for guidance, orientation, and protection of the subsea tree on the subsea wellhead/tubing head and that also provides support for tree flowlines and connection equipment, control pods, anodes, and counterbalance weights.~~

3.1.67

~~tree-side outlet~~

~~Point where a bore exits at the side of the tree block.~~

3.1.68

~~umbilical~~

~~Hose, tubing, piping, and/or electrical conductor that directs fluids and/or electrical current or signals to or from subsea trees.~~

3.1.69

~~upstream~~

~~Direction of movement towards the reservoir.~~

3.1.70

~~utility bolting~~

~~Threaded fasteners used to mount equipment and accessories to the production equipment.~~

~~EXAMPLES — Bolting on nameplates, clamps for tubing, guards, position indicator bolting, structural bolting, and miscellaneous attachment bolting.~~

3.1.71

~~valve block~~

~~Integral block containing two or more valves.~~

3.1.72

~~visible leakage~~

~~Leakage of test media seen either through direct observation or with the use of video equipment.~~

3.1.73

~~vertical tree~~

~~Tree with the master valve in the vertical bore of the tree below the side outlet.~~

3.1.74

~~wear bushing~~

~~Bore protector that also protects the casing hanger below it.~~

3.1.75

~~wellbore~~

~~Cavity that contains retained fluid.~~

3.1.76

~~wellhead (high-pressure) housing pressure boundary~~

~~Wellhead (high-pressure) housing from the top of the wellhead to where the lowermost of either the annulus seal assembly or the test tool seals.~~

~~Acronyms, Abbreviations, and Symbols~~

~~AAV—annulus access valve (or WOV)~~

~~AIV—annulus isolation valve~~

~~AMV—annulus master valve~~

~~ASV—annulus swab valve~~

~~AWV—annulus wing valve~~

~~BOP—blowout preventer~~

~~BPVC—Boiler and Pressure Vessel Code~~

~~BSL—bolting specification level~~

~~GGB—completion guidebase~~

~~GID—chemical injection—downhole~~

~~GIT—chemical injection—tree~~

~~GRA—corrosion-resistant alloy~~

~~GRM—corrosion-resistant material~~

~~C_v —flow coefficient (US customary units)~~

~~EDP—emergency disconnect package (see API 17G)~~

~~EF—enhancement factor~~

~~ER—equivalent round~~

~~FAT—factory acceptance test~~

~~FEA—finite element analysis~~

~~GRA—guidelineless re-entry assembly~~

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~~HPHT—high-pressure-high-temperature~~

~~HXT—horizontal-subsea-tree~~

~~ID—inside-diameter~~

~~K_v —flow-coefficient (SI units)~~

~~LWRP—lower-workover-riser-package (WCP + EDP) (see API 17G)~~

~~MGW—maximum-gross-weight~~

~~NA—not-applicable~~

~~NDE—nondestructive-examination~~

~~OD—outside-diameter~~

~~OEC—other-end-connectors~~

~~OWIRS—open-water-intervention-riser-system~~

~~PCV—production-choke-valve~~

~~PGB—permanent-guidebase~~

~~P&ID—piping-and-instrumentation-diagram~~

~~PMR—per-manufacturer-requirements~~

~~PMV—production-master-valve~~

~~POV—production-orifice-valve~~

~~PSL—product-specification-level~~

~~PSV—production-swab-valve~~

~~PWV—production-wing-valve~~

~~QA/QC—quality-assurance/quality-control~~

~~QTC—qualification-test-coupon~~

~~RMS—root-mean-square~~

~~ROV—remotely-operated-vehicle~~

~~RWP—rated-working-pressure~~

~~S_b —bending-stress~~

~~S_m —membrane-stress~~

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~~S_{MYS} —specified minimum yield strength~~

~~S_{YST} —yield strength at elevated temperatures~~

~~SCSSV—surface-controlled subsurface safety valve~~

~~SFC—steel forging class~~

~~SI—International System of Units~~

~~SIT—system integration test~~

~~TBIRS—through bore intervention riser system~~

~~TGB—temporary guidebase~~

~~USC—US customary~~

~~USV—underwater safety valve~~

~~VXT—vertical subsea tree~~

~~WCP—well control package (see API 17G)~~

~~WOV—workover valve (or AAV)~~

~~XOV—crossover valve~~

~~Application, Service Conditions, and Production Specification Levels~~

~~Application~~

~~Equipment within the scope of this specification is listed as follows, including eligible product specification levels (PSLs) (see 4.3) for components.~~

~~NOTE 1 Refer to Annex B for additional guidance on selection of PSL.~~

~~Components without PSL listed shall be per manufacturer requirements.~~

~~Subsea trees:~~

~~tree and tubing head connectors (PSL 2, 3);~~

~~valves, (multiple) valve block assemblies (PSL 2, 3, 3G);~~

~~chokes (PSL 2, 3, 3G);~~

~~actuators/operators (if actuator incorporates a bonnet, then actuator assembly shall follow valve PSL);~~

~~underwater safety valves (USVs) (PSL 2, 3, 3G);~~

~~tree cap (PSL 2, 3, 3G);~~

~~crown plugs (PSL 2, 3, 3G);~~

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~~tree piping (inboard);~~

~~tree frames and completion guidebases (CGBs);~~

~~tree running tools (PSL 2, 3);~~

~~tree cap running tools;~~

~~tubing heads (PSL 2, 3, 3G);~~

~~Subsea wellheads:~~

~~conductor (low-pressure) housings;~~

~~wellhead (high-pressure) housings (PSL 2, 3);~~

~~casing hangers (PSL 2, 3);~~

~~submudline casing hangers (PSL 2, 3);~~

~~annulus seal assemblies;~~

~~submudline annulus seal assemblies;~~

~~casing hanger lockdown bushings (PSL 2, 3);~~

~~guidebases;~~

~~bore protectors and wear bushings;~~

~~corrosion caps.~~

~~Mudline suspension systems:~~

~~landing rings (PSL 2, 3);~~

~~casing hangers (PSL 2, 3);~~

~~casing hanger running tools;~~

~~casing hanger tieback tools (PSL 2, 3);~~

~~subsea completion adaptors and tubing heads for mudline wellheads (PSL 2, 3);~~

~~corrosion caps.~~

~~Drill through mudline suspension systems:~~

~~external casing hangers (PSL 2, 3);~~

~~external casing hanger (wellhead) housings (PSL 2, 3);~~

~~internal casing hangers (PSL 2, 3);~~

~~internal annulus seal assemblies;~~

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~~bore protectors and wear bushings.~~

~~Tubing hanger systems:~~

~~tubing hangers (PSL 2, 3, 3G);~~

~~running tools (PSL 2, 3).~~

~~Miscellaneous equipment:~~

~~flanged end and studded outlet connections, including tees, crosses, and elbows (PSL 2, 3);~~

~~clamp hub-type connections (PSL 2, 3);~~

~~threaded end and studded outlet connections, including tees, crosses, and elbows (PSL 2, 3);~~

~~other end connections (PSL 2, 3);~~

~~ring joint gaskets.~~

~~NOTE 2 The user/purchaser can specify gas testing of miscellaneous equipment when assembled to the tree assembly.~~

~~This specification includes equipment definitions, an explanation of equipment use and function, an explanation of service conditions and PSLs, and a description of critical components, i.e. those parts having requirements specified in this specification.~~

~~The following is outside the scope of API 17D:~~

~~subsea well control packages (WCPs) and subsea test trees;~~

~~production risers;~~

~~intervention riser systems (TBIR, OWIR, and mudline suspension);~~

~~control systems and subsea control modules (control pods);~~

~~platform (well) tiebacks;~~

~~protective structures;~~

~~subsea process equipment;~~

~~subsea manifolds and jumpers and jumper connectors;~~

~~subsea wellhead tools;~~

~~multiple well template structures and interfaces;~~

~~subsea manifold piping.~~

~~Service Conditions~~

~~Pressure~~

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~~For this specification, pressure measurements shall be gauge pressure.~~

~~Temperature Classifications~~

~~Temperature classifications shall be used to indicate temperature ranges, from minimum (ambient or flowing) to maximum flowing fluid temperatures. Unless otherwise indicated, temperature classifications shall conform to API 6A.~~

~~Sour Service Designation and Marking~~

~~The user/purchaser shall specify materials of construction for pressure-containing and pressure-controlling equipment. Material classes AA-HH as defined in Table 1 shall be used to indicate the material of those equipment components. Guidelines for choosing material class based on the retained fluid constituents and operating conditions are given in API 6A and in Annex B of this specification.~~

~~When an H₂S partial pressure limit is specified by NACE MR0175/ISO 15156, a suffix value shall be marked after the material class designation in units consistent with the RWP marking. Where no H₂S limit is defined by NACE MR0175/ISO 15156 for the partial pressure, no partial pressure shall be marked. Use of materials in fluid conditions exceeding the limits defined in NACE MR0175/ISO 15156 or the use of materials not addressed in NACE MR0175/ISO 15156 should be described and marked as material class ZZ. For class ZZ, the manufacturer shall satisfy material specifications supplied or approved by the user/purchaser and shall maintain traceable records to document the materials of construction, regardless of PSL.~~

~~EXAMPLE —“FF 10” on equipment with the RWP marked in psi indicates material class FF rated with a 10 psi pp H₂S maximum allowable limit, when used within the environmental limits specified in NACE MR0175/ISO 15156.~~

~~For material classes DD, EE, FF, and HH, the manufacturer shall meet the requirements of NACE MR0175/ISO 15156 for material processing and material properties (e.g. hardness).~~

~~Product Specification Levels~~

~~NOTE 1 —Guidelines for selecting an appropriate PSL are provided in Annex B.~~

~~The PSL of an assembled system of wellhead or tree equipment shall be determined by the lowest PSL of any pressure-containing or pressure-controlling component in the assembly.~~

~~Structural components and other non-pressure-containing or non-pressure-controlling parts of equipment manufactured to this specification shall be defined by the manufacturer's specifications.~~

~~All pressure-containing components of equipment manufactured to this specification shall conform to the requirements of PSL 2, PSL 3, or PSL 3G, as a minimum, as established in API 6A. Pressure-controlling components shall conform to the requirements of PSL 2, PSL 3, or PSL 3G as specified in 5.4 and API 6A, except where additions, modifications, or exceptions are noted within this specification.~~

~~NOTE 2 —PSL designations define different levels of technical quality requirements as established in API 6A. PSL 4S defines the designation for an optional level of quality and testing requirements specifically intended for products used in high-pressure-high-temperature (HPHT) applications.~~

~~Products manufactured to the requirements of this specification shall satisfy the material, welding, quality, and testing requirements for a PSL (PSL 2 or PSL 3), when applicable.~~

~~NOTE 3 —PSL does not apply to all products of this specification.~~

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~~A supplemental designation of PSL 3G shall apply to PSL 3 products that have satisfied the PSL 3 requirements in addition to the requirements of gas testing.~~

~~The user/purchaser may specify additional gas testing for assemblies manufactured to PSL 3G (such as a VXT or HXT assembly) as an integral unit. The user/purchaser and manufacturer should agree to the scope of testing.~~

~~NOTE 4 — Alternative validation and quality process requirements above PSL 3, for carbon steel and low alloy steels, are listed in Annex C.~~

~~NOTE 5 — PSL 4S as defined in this specification exceeds PSL 3 and 3G requirements. See 5.4.2 and Annex D.~~

Common System Requirements

Design and Performance Requirements

General

Product Capability

~~Product capability shall be defined by the manufacturer based on analysis and testing, more specifically:~~

~~validation (see 5.1.7), which is to demonstrate performance of generic product families, by representative testing of defined product variants;~~

~~performance requirements, which define the operating capability of the specific “as-shipped” items (as specified in 5.1.1 and 5.1.2), which is demonstrated by reference to both FAT and relevant validation data.~~

~~NOTE — Performance requirements are only applicable to newly manufactured products and do not apply to products after they have been put into service.~~

~~All products shall be designed and tested for their application in accordance with 5.1, 6.1, and Section 7 through Section 11.~~

Pressure Integrity

~~Product designs shall be capable of withstanding RWP at rated temperature without exceeding stress criteria and without experiencing deformation that prevents meeting any other performance requirement, in accordance with 5.1.3.~~

Thermal Integrity

~~Product designs shall be capable of functioning throughout the temperature range for which the product is rated. Components shall be designed for the maximum and minimum rated operating temperatures. Rated range of a component shall include all temperatures the component can experience in service.~~

~~NOTE 1 — Thermal analysis can be used to establish component temperature operating requirements.~~

~~NOTE 2 API 6A provides information for design and de-rating of equipment for use at elevated temperatures. Annex D provides additional information on material characterization and de-rating at higher temperatures.~~

~~Transitional low-temperature effects associated with Joule-Thomson (J-T) cooling and well start-up conditions may be addressed by one or more of the following methods:~~

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~~component validation to the required minimum temperature as specified in 5.1.7;~~

~~component validation to the standard operating temperature range combined with material Charpy V-notch validation at or below the minimum transitional operating temperature in accordance with 4.2.2;~~

~~component validation to the standard operating temperature range combined with additional material documentation supporting suitability for operation at the transitional temperature range.~~

Materials

~~Product shall be designed with material class selected from Table 1 and shall conform to the requirements of API 6A.~~

Table 1—Material Requirements

Materials Class	Body, Bonnet, End and Outlet Connectors	Mandrel Hangers, Valve Bore Sealing Mechanisms, Metal Seals, and Stems
AA—General service	Carbon or low-alloy steel, or stainless steel or CRA^d	Carbon or low-alloy steel, or stainless steel or CRA^d
BB—General service	Carbon or low-alloy steel, or stainless steel or CRA^d	Stainless steel or CRA^d
CC—General service	Stainless steel or CRA^d	Stainless steel or CRA^d
DD—Sour service^a	Carbon or low-alloy steel or CRA^{b,d}	Carbon or low-alloy steel, or stainless steel or CRA^{b,d}
EE—Sour service^a	Carbon or low-alloy steel or CRA^{b,d}	Stainless steel or CRA^{b,d}
FF—Sour service^a	Stainless steel or CRA^{b,d}	Stainless steel or CRA^{b,d}
HH—Sour service^a	CRA^{b,c,d}	CRA^{b,c,d}
ZZ	API 6A	API 6A
As defined by NACE MR0175/ISO 15156.		
In accordance with NACE MR0175/ISO 15156.		
CRA required on retained fluid wetted surfaces only; CRA cladding of low-alloy or stainless steel is permitted (see 5.3.3).		

~~Equipment shall be constructed with materials (metallics and nonmetallics) suitable for its respective material classification in accordance with Table 1. Table 1 does not define all factors within the wellhead environment but provides material classes for various levels of service conditions and relative corrosivity.~~

~~Material requirements shall conform to Table 1. All wellbore wetted pressure-containing components shall be treated as “bodies” for determining material trim requirements from Table 1. However, in this specification, other wellbore pressure boundary penetration equipment, such as grease and bleeder fittings, shall be treated as “stems” as set forth in Table 1. Metal seals shall be treated as pressure-controlling parts with regard to Table 1.~~

~~For material classes AA-CC, all pressure-containing components exposed to wellbore fluids shall be in accordance with Table 1.~~

~~For material classes DD-HH, all pressure-containing components exposed to wellbore fluids shall be in accordance with Table 1 and NACE MR0175/ISO 15156 (all parts).~~

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~~For material class ZZ, all pressure-containing components exposed to wellbore fluids shall be in accordance with API 6A.~~

~~Load Capability~~

~~Product designs shall be capable of sustaining rated loads without exceeding stress criteria and without experiencing deformation to such an extent that prevents meeting any other performance requirement. Product designs that support tubulars shall be capable of supporting the rated load without collapsing the tubulars below the drift diameter.~~

~~NOTE 1 — Design requirements and criteria found in this specification are based on RWP and external loads relevant for installation, testing, and normal events. For extreme and survival events, refer to API 17TR7, API 17TR8, or API 17G.~~

~~Design requirements due to drilling riser or workover riser imparted loads shall be determined by the manufacturer, and overall operating limits documented.~~

~~NOTE 2 — See API 17G for design requirements for intervention riser loads and API 16Q for drilling riser loads.~~

~~Cycles~~

~~Product designs shall be capable of performing and operating in service as intended for the number of operating cycles as specified by the manufacturer. Products shall be designed to operate for the required pressure/temperature cycles, cyclic external loads, and multiple make/break (latch/unlatch).~~

~~Operating Force or Torque~~

~~Products shall be designed to operate within the manufacturer's force or torque specification.~~

~~Service Conditions~~

~~Pressure Ratings~~

~~Equipment, except actuators, shall be designed to operate at only the standard rating pressure identified in Table 2. The standard pressure rating shall be used as the RWP for all testing.~~

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Table 2—Equipment Standard Pressure Rating

Equipment	Pressure Rating		
	5000-psi- (34.5 MPa)	10,000-psi- (69.0 MPa)	15,000-psi- (103.5 MPa)
Valves, chokes	X	X	X
Pressure-containing equipment ^a	X	X	X
Pressure-controlling equipment ^a	X	X	X
Tree and tubing head connectors	X	X	X
Tubing hangers ^b	X	X	X
Tree and tubing hanger downhole conduits ^{b, c}	PMR		
Wellhead (high-pressure) housing	X	X	X
Casing hangers/internal wellhead components ^{f, g}	PMR		
Mudline suspension equipment ^d	Per Section 10		
Drill-through mudline equipment ^d	Per Section 11		
Hydraulic components	PMR		
Other ^e	PMR		
PMR = per manufacturer requirements.			
^a Only standard pressures apply unless specifically noted elsewhere in this table.			
^b May contain flow passages that shall not exceed 1.0 times the RWP of the tubing hanger assembly plus 2500 psi (17.2 MPa). Production and annulus tubing connections may have a pressure rating lower than the tubing hanger RWP.			
^c Intermediate pressure rating permitted if component requires a design greater than working pressure.			
^d Rated for working pressure in accordance with the methods given in Section 10 and Annex E.			
^e Not listed in this table, such as running, retrieval, and test tools.			
^f Threaded connections may have a pressure rating lower than the assembly RWP, to be defined PMR.			

~~9 — Tools and internal components, such as casing hangers, may have other pressure ratings, depending on size, connection thread, and operating requirements.~~

~~Where small diameter lines [e.g. surface-controlled subsurface safety valve (SCSSV) control lines, chemical injection lines] pass through a cavity, such as the tree/tubing hanger cavity, the equipment bounding that cavity shall be designed for the maximum pressure in any of these lines unless a means is provided to monitor and relieve cavity pressure (see Table 6, 7.9.1, and 9.1.7 for additional information).~~

~~Intermediate pressure ratings [e.g. 7500 psi (51.7 MPa)] shall not be applied except where noted in the footnotes of Table 2.~~

~~NOTE Pressure ratings that do not conform to Table 2 are outside the normative scope of this specification. See Annex D for pressure ratings above 15,000 psi.~~

~~Threaded Equipment Limitations~~

~~Equipment designed for a mechanical connection with small bore connections [up to 1.00 in. (25.4 mm) bore], test ports, and gauge connections shall be internally threaded, shall conform to the limits on use specified in 7.3, and shall conform to the size and RWP limitations in Table 3.~~

~~OECs, with internal threads and meeting the requirements of 7.3 that are designed specifically for small-bore, test-port, or gauge-connection applications, may also be used.~~

~~Table 3 shall not apply to tubing and casing hangers.~~

~~**Table 3—Pressure Ratings for Internal Thread End or Outlet Connectors**~~

Type of Thread	Nominal Size	Rated Working Pressure
API line pipe (sizes)	$\frac{1}{2}$–(12.7)	10,000 (69.0)
High-pressure connections	Test and gauge connector ports per API 6A	$\geq 15,000$ (103.5)

~~Temperature Ratings~~

~~Standard Operating Temperature Rating~~

~~Equipment covered by this specification shall be rated to operate throughout a temperature range defined by the manufacturer and as a system in accordance with API 6A.~~

~~The minimum classification for the subsea system in accordance with this specification shall be temperature classification V [35 °F (2 °C) to 250 °F (121 °C)]. When impact toughness is required of materials (PSL 3 and PSL 3G), the minimum classification for pressure-containing and pressure-controlling materials should be temperature classification U [0 °F (–18 °C) to 250 °F (121 °C)].~~

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~~Valve and choke actuators/operators standard operating temperature range shall be 35 °F (2 °C) to 150 °F (66 °C), and marked accordingly.~~

~~Nonstandard temperature ranges shall be demonstrated by analysis and/or validation, and marked accordingly.~~

~~NOTE 1 — For nonstandard temperature ranges that can be described by letter designations, the first letter denotes the minimum temperature rating and the second letter the maximum temperature rating, e.g. VX or V-X. Alternatively, for nonstandard temperature ranges that cannot be described by letter designations, the actual temperature rating can be marked, e.g. -25 °F to 125 °F.~~

~~NOTE 2 — Predeployment testing at the surface may be conducted at environmental temperatures lower than the system rating as specified by the manufacturer. It is not necessary that the product validation be performed at the predeployment testing temperature.~~

~~NOTE 3 — Transitional low temperature effects are outside the designated temperature rating.~~

~~Standard Operating Temperature Rating Adjusted for Seawater Cooling~~

~~If analysis or testing demonstrates that component does not exceed a lower designated temperature rating, then that equipment shall, at the manufacturer's option, be designated and rated to operate at that lower temperature.~~

~~Subsea components and equipment that are thermally shielded from seawater by insulating materials shall be demonstrated by calculation or thermal analysis that they can work within temperature range of the designated temperature classification.~~

~~Site Testing Environment~~

~~Site testing environmental requirements (along with any specific requirements) shall be provided by the manufacturer. If subsea equipment will be stored or tested on the surface at temperatures outside of its temperature rating, then the manufacturer should be contacted to determine if special storage or surface-testing procedures are recommended.~~

~~Design Methods and Criteria~~

~~General~~

~~All pressure-containing parts and all pressure-controlling parts shall be designed to satisfy the manufacturer's documented performance characteristics and the service conditions in Section 4. The manufacturer shall document engineering practices and acceptance criteria on which the design is based.~~

~~NOTE 1 — Specific loading conditions are identified per product in this specification.~~

~~NOTE 2 — It is the user/purchaser responsibility to confirm that anticipated operating loads are within the operating limits of the equipment being used for the specific application.~~

~~Standard API Flanges, Hubs, and Threaded Equipment~~

~~Flange and hub designs for subsea use shall conform to 7.1, 7.2, and/or 7.3.~~

~~Pressure-controlling Components~~

~~Unless otherwise noted in this specification, pressure-controlling components shall be designed in accordance with API 6A.~~

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Pressure-containing Components

Pressure-containing component designs shall conform to API 6A.

Bolting

General

The manufacturer shall specify the bolting preload for RWP and normal operating loads.

API flange bolting shall be made up for face-to-face flange contact and bolting shall have a minimum preload stress of 50 % of bolting S_{MYS} after flange make-up. Additional bolt preload stress may be applied to assure face-to-face flange contact and should not exceed 67 % of bolting S_{MYS} .

NOTE 1 Refer to 5.1.3.5.5 for closure bolting and 5.1.3.5.7 for critical bolting on OECs.

Critical bolting, closure bolting, and pressure-controlling bolting used on subsea completion equipment shall conform to API 6A and any additional requirements defined in this document.

NOTE 2 For bolting that has been in service, refer to API 6AR.

Requirements

Bolting used in subsea service shall conform to the requirements of Table 4.

Table 4—Bolting Classifications and Material Requirements

Bolting Classification	Material	Reference
Utility	Alloy and carbon steel	Per manufacturer specification
	Stainless steel and CRA	Per manufacturer specification
Pressure-controlling	Alloy and carbon steel	Per manufacturer specification
	Stainless steel and CRA	Per manufacturer specification
Closure ^a	Alloy and carbon steel ^b	API 20E, BSL2
	Stainless steel and CRA	API 20F, BSL2 ^c
Lifting bolting	Alloy and carbon steel ^b	API 20E, BSL2
	Stainless steel and CRA	API 20F, BSL2 ^c
Critical ^a	Alloy and carbon steel ^b	API 20E, BSL3
	Stainless steel and CRA	API 20F, BSL3
<p>^a See API 6A for guidance on bolting material selection.</p> <p>^b For 105 ksi (725 MPa) 0.2 % offset yield strength studs, bolts, or cap screws ≥ 2.5", the bolting material shall be ASTM A320/A320M L43.</p> <p>^c The use of an unlisted bolting material shall be as agreed between the manufacturer and user/purchaser and shall be in accordance with specific requirements in API 20F for BSL2, excluding any specific grade/alloy requirements.</p>		

For material classes DD, EE, FF, and HH, bolting that is covered by insulation shall be treated as exposed bolting in accordance with NACE MR0175 (all parts).

Utility Bolting

Utility bolting manufactured from carbon or alloy steel, when used in submerged service, shall be limited to 35 HRC (327 HBW) to facilitate the use of standard ASTM specifications.

Pressure-controlling Bolting

Pressure-controlling bolting manufactured from carbon or alloy steel, when used in submerged service, shall be limited to 34 HRC (319 HBW).

Closure and Critical Bolting

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~~Manufacturers shall document the design make-up tension (or torque) for closure bolting and critical bolting using tables, similar to the one in Annex F. The torque table(s) shall be supported by documented validation results.~~

~~Calibrated torque or bolt-tensioning equipment shall be used to ensure accurate make-up tension for closure bolting and critical bolting.~~

~~Lifting Bolting~~

~~Lifting bolting used within the scope of this specification shall be assembled using torque (or other validated bolt preload method) that achieves a tensile make-up stress sufficient to keep the membrane stresses based on the tensile stress area below yield under test conditions and under worst case load conditions.~~

~~NOTE—Consult local regulations for bolting requirements used in direct lifting load path.~~

~~Structural Components~~

~~If specific design requirements in Section 6 through Section 11 differ from the general requirements in Section 5, then the equipment's specific design requirements shall take precedence.~~

~~Design requirements for structural components (not pressure-controlling or pressure-containing) not otherwise identified in this specification shall be in accordance with one or more of the following:~~

~~accepted industry practices using a design factor of 1.5 or more based on specified minimum yield strength;~~

~~finite element analysis (FEA) used to demonstrate that applied loads do not result in deformation to such an extent that prevents meeting any other performance requirement.~~

~~Design of Equipment for Lifting~~

~~General~~

~~NOTE—See Annex G for design, testing, and maintenance guidelines for lifting equipment.~~

~~Equipment used exclusively for running in, on, or out of the wellbore should be designed as given in 5.1.3.6 or 5.1.3.7 and Annex G or Annex H, as applicable.~~

~~Pad Eyes~~

~~Pad eyes should be designed as given in Annex G. Load capacities of pad eyes shall be marked as specified in 5.5.2.~~

~~Primary Members~~

~~If the primary member is either pressure-containing or pressure-controlling and is designed to be pressurized during lifting operations, then the load capacity shall include the additional stresses induced by internal RWP.~~

~~Miscellaneous Design Information~~

~~Tolerances~~

~~Unless otherwise specified in tables or figures of API 17D, the following tolerances shall apply.~~

~~The tolerance for dimensions with format X. X is ± 0.1 in. (X is ± 2.5 mm).~~

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~~The tolerance for dimensions with format X.XX is ± 0.02 in. (X.X is ± 0.5 mm).~~

~~The tolerance for dimensions with format X.XXX is ± 0.005 in. (X.XX is ± 0.13 mm).~~

~~Dimensions listed as XXXX/YYYY are considered the maximum dimension (XXXX) and the minimum dimension (YYYY), overriding the nominal tolerances to accommodate certain geometries.~~

~~End and Outlet Bolting~~

~~Hole Alignment~~

~~End and outlet bolt holes for API flanges shall be equally spaced and shall straddle the common center line (see Table 9).~~

~~Stud-thread Engagement~~

~~Stud-thread engagement length into the body of API studded flanges shall be a minimum of one times the outside diameter (OD) of the stud.~~

~~Other Bolting~~

~~The stud-thread anchoring means shall be designed to sustain a tensile load equivalent to the load that can be transferred to the stud through a fully engaged nut.~~

~~Test, Vent, Injection, and Gauge Connections~~

~~Sealing~~

~~All test, vent, injection, and gauge connections shall provide a leak-tight seal at the test pressure of the equipment in which they are installed.~~

~~A means shall be provided such that any pressure behind a test, vent, injection, or gauge connector can be safely vented prior to removal of the component.~~

~~Test and Gauge Connection Ports~~

~~Test and gauge connection ports shall conform to the requirements of 5.1.2.2 and 7.3.~~

~~Coatings (External)~~

~~Methods~~

~~The coating system and procedure used shall conform to the written specification of the equipment manufacturer or the coating manufacturer as agreed between the user/purchaser and manufacturer.~~

~~The manufacturer shall maintain, and have available for review, documentation specifying the coating systems and procedures used.~~

~~NOTE—See Annex I.~~

~~Color Selection~~

~~Color selection for underwater visibility shall be in accordance with API 17H.~~

~~Cathodic Protection~~

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~~The cathodic protection system design shall conform to the manufacturer's written specification and in accordance with either of the following design codes:~~

~~NACE SP0176;~~

~~DNV-RP-B401.~~

~~This documentation shall contain the following information as a minimum:~~

~~location and size of wetted surface area for specific materials, coated and uncoated;~~

~~areas where welding is allowed or prohibited;~~

~~materials of construction and coating systems applied to external wetted surfaces;~~

~~control line interface locations;~~

~~flowline interfaces.~~

~~NOTE Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Materials that have shown this susceptibility include martensitic stainless steels and the more highly alloyed steels having yield strengths over 900 MPa (131,000 psi). Other materials subject to this phenomenon are hardened, low-alloy steels, particularly with hardness levels greater than Rockwell "C" 35 [with yield strength exceeding 900 MPa (131,000 psi)], precipitation hardened nickel-copper alloys and some high-strength titanium alloys.~~

Monitoring

~~Designs shall facilitate monitoring of cathodic protection potentials of subsea equipment. Cathodic protection monitoring location shall be identified that provides a representative potential.~~

Design Documentation

~~Documentation of designs shall include methods, assumptions, calculations, validation reports, and design-validation requirements. Design documentation requirements shall include, but not be limited to, those criteria for size, test and operating pressures, material, environmental requirements, and other pertinent requirements on which the design is being based. Design documentation media shall be clear, legible, reproducible, and retrievable. Design documentation retention shall be for a minimum of 5 years after the last unit of that model, size, and RWP is manufactured. All design requirements shall be recorded in a manufacturer's specification, which shall reflect the requirements of this specification.~~

Design Review

~~Design documentation shall be reviewed and verified by any qualified individual other than the individual who created the original design.~~

Validation

Introduction

~~The minimum validation procedures that shall be used to validate product designs in accordance with Table 5 are defined in 5.1.7. The manufacturer shall define additional validation that are applicable and demonstrate that this validation can be correlated with the intended service life and/or operating conditions in accordance with the user/purchaser requirements.~~

General

~~Prototype equipment (or first article) and fixtures used to validate designs shall be representative of production models in terms of design, production dimensions/tolerances, intended manufacturing processes, deflections, and materials. If a product design undergoes a substantive change, the manufacturer shall document the impact of such changes on the performance of the product. Documentation shall contain an explanation of the change if revalidation is not required.~~

~~For items with primary and secondary independent seal mechanisms, the seal mechanisms shall be independently validated unless the primary and secondary seal mechanisms are identical. Equipment should be validated with the minimal lubricants required for assembly unless the lubricants can be replenished when the equipment is in service or is provided for service in a sealed chamber.~~

~~The actual dimensions of equipment subjected to validation shall be within the allowable range for dimensions specified for normal production equipment.~~

~~NOTE—Annex J provides information on a consistent method of conducting validation on valves conforming to this specification, by prescribing the types of cycles and the order in which the cycles are to be performed.~~

Test Media

~~Hydrostatic body pressure tests of test equipment used for validation shall be performed at ambient temperature using a liquid as the test medium before the start of any validation pressure test program.~~

~~For pressure hold periods, gas test media shall be required for pressure-containing and pressure-controlling equipment. Gas is the preferred test medium in all other cases for pressure-containing and pressure-controlling equipment for which the purpose of the test includes validating one or more seals.~~

~~For pressure cycling tests without hold periods, the test media may be liquid or gas.~~

~~Pressure hold periods conducted for pressure-containing and pressure-controlling equipment for the purpose of validating external pressure capacities may use liquid as the test medium. Test procedures and acceptance criteria shall meet the requirements in 5.4.~~

Pressure-cycling Tests

~~Table 5 lists equipment that shall be subjected to repetitive pressure cycling tests simulating well start-up and shutdown pressure cycling that occurs in long term field service. For these tests, the equipment shall be alternately pressurized to the full RWP and then depressurized to 1 % or less of the test pressure until the specified number of pressure cycles has been completed.~~

~~NOTE—No holding period is required for each pressure cycle.~~

~~If applicable, equipment shall be tested per 5.4.5.1 prior to pressure cycling testing. Pressure test cycles that are conducted during the temperature cycling test can satisfy both pressure and temperature cycling requirements. After pressure cycle testing, a 1.0 RWP body pressure test shall be performed per 5.4.5.1 or 5.4.6.3, as applicable per PSL.~~

Load Testing

~~The manufacturer's rated load capacities for equipment in accordance with this specification shall be verified by both validation testing and engineering analysis. The equipment shall be loaded to the rated capacity to the number of cycles in accordance with Table 5 during the test without deformation to such an extent that any other performance requirement is affected (unless otherwise specified). Engineering analysis shall be conducted using techniques and programs that conform to documented industry practice.~~

Table 5—Minimum Validation Requirements

Equipment	Pressure/Load Cycling Test	Temperature Cycling Test ^a	Endurance—Cycling Test (Total Cumulative Cycles)
Metal seal exposed to retained fluids ^g	200	3	PMR
Metal seal not exposed to retained fluids ^g	3	3	PMR
Nonmetallic seal exposed to retained fluids	200	3	PMR
Nonmetallic seal not exposed to retained fluids	3	3	PMR
OEC	200	3	PMR
Wellhead/tree/tubing head connectors ^e	3	NA	PMR ^e
Tubing heads	3	NA	NA
Valves operated with actuators ^b	200	3	600
Manual valves	200	3	400 ^f
Valve actuators/operators (alone but under load)	200	3	600
Tree cap connectors	3	NA	PMR
Manual subsea chokes	200	3	500 ^{d, f}
Subsea chokes operated with actuators	200	3	1000 ^d
Subsea wellhead casing hangers and submudline casing hangers	3	NA	NA
Subsea wellhead annulus seal assemblies (including backup seal assemblies) and submudline annulus seal assemblies	3	3	NA
Subsea tubing hangers, HXT internal tree caps and crown plugs	3	NA	NA
Poppets, sliding sleeves, and check valves	200	3	PMR
Mudline tubing heads	3	NA	NA
Mudline wellhead, casing hangers, tubing hangers	3	NA	NA
Running tools (including tree running tool connectors) ^g	3	NA	PMR
NOTE—Pressure cycles, temperature cycles, and endurance cycles are run as specified above in a cumulative test with one product without changing seals or components.			

~~Temperature cycles shall be in accordance with API 6A.~~

~~Before and after the pressure cycle test, a low pressure, 300 psi \pm 30 psi (2 MPa \pm 0.2 MPa), leak-tightness test shall be performed.~~

~~Subsea wellhead running tools are not included.~~

~~A choke-actuator/operator cycle is defined as total choke stroke from full-open to full-close or full-close to full-open.~~

~~For PR1, per PMR. For PR2, refer to API 17TR7 (see 7.8.3.3).~~

Temperature Cycling Tests

~~Validation shall be performed at or beyond the rated operating temperature range, or component temperature operating requirements as defined in 5.1.1.3, while at RWP or load condition.~~

~~Table 5 lists equipment that shall be subjected to repetitive temperature cycling tests simulating start-up and shutdown temperature cycling that occur in long-term field service. For these temperature cycling tests, the equipment shall be alternately heated and cooled to the upper and lower temperature extremes of its rated operating temperature classification as defined in 5.1.2.3. During temperature cycling, RWP shall be applied to the equipment at the temperature extremes with API 6A.~~

~~NOTE—Pressure test cycles that are conducted during the temperature cycling test can satisfy both pressure and temperature cycling requirements.~~

~~As an alternative to testing, objective evidence shall ensure that the equipment will meet performance requirements at both temperature extremes.~~

Life Cycle/Endurance Testing

~~Table 5 lists equipment that shall be subjected to extended life cycle/endurance testing to simulate long-term field service. For these life cycle/endurance tests, the equipment shall be subjected to operational cycles in accordance with the manufacturer's performance specifications (i.e. make-up to full torque/break-out, open/close under full RWP). Connectors, including stabs, shall be subjected to a full disconnect/lift as part of the cycle.~~

~~NOTE—Additional requirements for life cycle/endurance testing can be found in the equipment-specific sections covering these items (see Section 6 to Section 11).~~

~~Secondary functions, such as connector secondary unlock, shall be included in life cycle/endurance testing.~~

~~Where it can be demonstrated that pressure and/or temperature testing similarly loads the component or assembly to that condition specified for endurance cycle testing, those cycles may be accumulated toward the total number of cycles specified for endurance cycle testing. For example, the 200/3 pressure/temperature cycles used to test a valve may cumulatively qualify as 203 cycles toward the 600 total cycles required for endurance cycling.~~

Product Family Validation

~~A product of one size may be used to verify other sizes in a product family, provided the following requirements are met.~~

~~A product family is a group of products for which the design principles, physical configuration, and functional operation are the same, but which differ in size.~~

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~~The product geometries are parametrically modelled such that the design stress levels and deflections in relation to material mechanical properties are based on the same criteria for all members of the product family in order to verify designs via this method.~~

~~Scaling may be used to verify the members of a product family in accordance with API 6A.~~

Documentation

~~Validation procedures and test results shall be documented. The documentation requirements for validation testing shall be the same as the documentation requirements for design documentation in 5.1.5 with the addition that the documentation shall identify the person(s) conducting and witnessing the tests and the time and place of the testing.~~

Materials

General

Manufacturing Requirements

~~All materials shall be manufactured in accordance with API 6A with the following modifications and exceptions listed below.~~

~~For purposes of this reference, subsea wellheads, tubing head inner bodies, valve bodies, and composite valve block valve bodies, tubing hanger bodies, and re-entry hubs shall be considered pressure-containing parts. "High-load-bearing" describes a load condition acting on a component such that the resulting loaded equivalent stress exceeds 50 % of the base material's minimum yield strength.~~

~~Valve actuators are not pressure-containing or pressure-controlling parts of equipment. Where the valve stem and/or valve bonnet are integral to the actuator, these components shall be classified as pressure-containing and/or pressure-controlling, as appropriate.~~

~~NOTE Other accepted manufacturing/process practices associated with material characterization and performance include API 20B, API 20C, API 20H, API 6HT, and API 17TR8.~~

Heat Treatment and Qualification Test Coupons

~~Heat treatment practices and qualification test coupons (QTCs) for this specification shall conform to API 6A.~~

Corrosion

Corrosion from Retained Fluids

~~Material selection based upon wellbore fluids shall be made in accordance with 5.1.1.4.~~

Corrosion from Marine Environment

~~Corrosion protection through material selection based on a marine environment shall, as a minimum, include impacts from the following:~~

~~external fluids;~~

~~internal fluids;~~

~~weldability;~~

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~~crevice corrosion;~~

~~dissimilar metals effects;~~

~~cathodic protection effects;~~

~~coatings.~~

~~Welding~~

~~Pressure-containing/controlling Components~~

~~All welding on pressure-containing/controlling components shall conform to the requirements of API 6A for PSL 2 or PSL 3, as specified.~~

~~Structural Components~~

~~Structural welds shall be treated as non-pressure-containing welds. Structural welds shall meet one of the following industry standards:-~~

~~a documented structural welding code, such as AWS D1.1/D1.1M;~~

~~weld design classifications that conform to API 17P.~~

~~Weld locations where the loaded stress exceeds 50 % of the weld or base material yield strength shall be identified as "critical welds" and shall be surface nondestructive examination (NDE) inspected in accordance with API 6A, PSL 3.~~

~~Hardfacing and Overlays~~

~~Corrosion-resistant Overlays~~

~~Corrosion-resistant overlays shall conform to API 6A for the following:~~

~~overlay of wetted surfaces of pressure-containing and pressure-controlling parts to meet material class;~~

~~overlay of ring grooves;~~

~~overlay of stems;~~

~~overlay of valve bore sealing mechanisms;~~

~~overlay of sealing surfaces with metal seals;~~

~~overlay of choke trim.~~

~~NOTE These requirements apply for weld overlay for corrosion resistance and/or hardfacing and other material properties with respect to retained fluids, the base metal, and sealing materials (surface hardness galling resistance and dissimilar metals corrosion).~~

~~Overlay for Other Than Corrosion Resistance~~

~~Hardfacing or other weld metal overlays for applications other than corrosion resistance shall conform to API 6A and manufacturer's written specification.~~

Quality Control

General

~~Equipment manufactured to this specification shall conform to the quality control and record requirements of API 6A. For those components not covered in API 6A, equipment-specific quality control requirements shall conform to the manufacturer's written specifications.~~

~~The manufacturer shall have a quality management system that conforms to an internationally recognized quality management standard.~~

~~All outsourced manufacturing processes shall meet the requirements of the manufacturer's quality management system.~~

~~Processes eligible to be outsourced shall include, but not be limited to, heat treatment, welding, machining, nondestructive testing, and coating. The manufacturer shall maintain documentation of the manufacturing process controls used for outsourced processes.~~

Product Specification Level

~~Quality control and testing for pressure-containing and pressure-controlling components covered by this part of API 17D shall conform to requirements for PSL 2 or PSL 3 as established in API 6A. Pressure testing shall meet the requirements of API 6A except for valves and chokes, which shall conform to 5.4.5 or 5.4.6 dependent upon PSL. Requirements for other components shall be in accordance with the manufacturer's written specification.~~

~~NOTE "PSL 4S" as defined in this specification is a designation for an optional level of quality and testing requirements specifically intended for products used in HPHT applications (see Annex D).~~

Structural Components

~~Quality control and testing of welding for structural components shall be specified as non-pressure-containing welds and conform to API 6A or a documented structural welding code, such as AWS D1.1/D1.1M. "Critical welds" shall be treated as pressure-controlling welds and conform to API 6A, PSL 3, excluding volumetric NDE examination.~~

Lifting Devices

~~NOTE Guidelines for sizing and calculating stresses of lifting pad eyes are defined in Annex G.~~

~~Additionally, welds on pad eyes and other lifting devices attached by welding shall be in accordance with the weld requirements as specified in 5.3.2 and 5.4.3. All pad eye and lifting device welds shall be designated as "critical welds." Lifting pad eyes shall also be individually proof load tested to at least two and one-half (2.5) times the documented maximum gross weight (MGW) for the individual pad eye (MGW/number of pad eyes). Pad eyes shall undergo NDE with magnetic particle examination and/or dye (liquid) penetrant following proof testing. Proof load testing shall be repeated following significant repairs or modifications prior to being put into use. The base metal and welds of pad eyes and other lifting devices shall meet PSL 3 requirements. Sea fastening points and pad eyes not used for lifting do not require proof test.~~

Testing for PSL 2, PSL 3, and PSL 3G Equipment

Hydrostatic Pressure Testing

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~~Procedures for hydrostatic pressure testing of equipment specified in Section 6 through Section 11 shall conform to the requirements for PSL 2, PSL 3, or PSL 3G in accordance with API 6A, with the exception that parts may be painted prior to testing.~~

~~For all pressure ratings, the hydrostatic body test pressure shall be a minimum of 1.5 times the RWP and the hydrostatic seat test pressure shall be a minimum of 1.0 times the RWP. The acceptance criterion for hydrostatic pressure tests shall be no visible leakage during the hold period. The final settling pressure shall not fall below the test pressure at the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test. Hydrostatic pressure testing shall be conducted at ambient temperature.~~

~~Loose flanges shall not require a hydrostatic body test prior to final acceptance.~~

~~Momentary pressure drops during the hold period due to sensitivity/noise in electronic data acquisition systems are permitted so long as the final pressure recorded is above the specified minimum test pressure and measurement devices have remained isolated from the pressure source throughout the entire hold period. If a pressure monitoring gauge and/or chart recorder is used for documentation purposes, the chart record may have a pressure settling rate not exceeding 3 % of the test pressure, or 300 psi (2 MPa) per hour, whichever is less.~~

~~Hydrostatic pressure test referenced to in API 17D is considered equivalent to the API 6A reference for a shell test or hydrostatic shell test.~~

~~Drift Test~~

~~Vertical runs, with direct access that require the passage of wellbore tools shall be physically drifted with the API 6A specified drift mandrel.~~

~~When direct access is not possible, an alternate method of meeting drift requirements shall be used such as the use of a borescope and/or visual inspection, provided the procedure has been validated with a calibrated (go/no-go) physical drift test for the given bore size.~~

~~Additional Testing for PSL 3G Equipment~~

~~Pressure Testing~~

~~Procedures for body testing of equipment specified in Section 6 through Section 11 shall conform to the requirements for PSL 3G in accordance with API 6A, with the exception that parts may be painted prior to testing.~~

~~Hydrostatic Body and Seat Test~~

~~A hydrostatic body test and hydrostatic valve seat tests (PSL 3) shall be performed per 5.4.5.1 prior to any gas testing.~~

~~Gas Body Test for Assembled Equipment~~

~~The test shall be conducted under the following conditions.~~

~~The test shall be conducted at ambient temperature.~~

~~The test medium shall be nitrogen.~~

~~The test shall be conducted with the equipment completely submerged in a water bath, unless an alternative leak detection means is agreed to between the user/purchaser and the manufacturer.~~

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~~Valves and chokes shall be tested with the closure mechanism positioned to ensure unrestricted flow and pressure into all internal wetted surface areas of the body.~~

~~The gas body test for assembled equipment shall consist of a single holding period of not less than 15 minutes, the timing of which shall not start until the test pressure has been reached and the equipment and pressure-monitoring gauge have been isolated from the pressure source.~~

~~The test pressure shall equal the RWP of the equipment.~~

~~Gas body testing shall be 1.0 times the RWP. The acceptance criterion for gas tests shall be no visible leakage during the hold period. The final settling pressure shall not fall below the test pressure at the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.~~

~~Momentary pressure drops during the hold period due to sensitivity/noise in electronic data acquisition systems are permitted so long as the final pressure recorded is above the specified minimum test pressure and measurement devices have remained isolated from the pressure source throughout the entire hold period. If a pressure-monitoring gauge and/or chart recorder is used for documentation purposes, the chart record may have a pressure settling rate not exceeding 3 % of the test pressure, or 300 psi (2 MPa) per 15 minutes, whichever is less.~~

~~Gas Seat Test—Valves~~

~~The gas seat test may be conducted in addition to, or in place of, the hydrostatic seat test.~~

~~The test shall be conducted under the following conditions:~~

~~The gas pressure shall be applied to each side of gate or plug of bidirectional valves with the other side open to the atmosphere. Unidirectional valves shall be tested in the direction indicated on the body, except for check valves, which shall be tested from the downstream side.~~

~~The test shall be conducted at ambient temperatures.~~

~~The test medium shall be nitrogen.~~

~~The test shall be conducted with the equipment completely submerged in a bath of water unless an alternative leak detection means is agreed to between the user/purchaser and the manufacturer.~~

~~Testing shall consist of two, monitored holding periods.~~

~~The primary test pressure shall equal RWP.~~

~~The primary test monitored hold period shall be 15 minutes.~~

~~The pressure shall be reduced to zero between the primary and secondary hold points, but not by opening the valve.~~

~~The secondary test pressure shall be 300 psi \pm 30 psi (2 MPa \pm 0.2 MPa).~~

~~The secondary test monitored hold period shall be 15 minutes; the upstream pressure is then vented to zero, but not by opening the valve.~~

~~The valves shall be fully opened and fully closed between tests.~~

~~Bidirectional valves shall be tested on the other side of the gate or plug using the same procedure.~~

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~~Gas seat test pressure test shall be 1.0 times the RWP. The acceptance criterion for gas tests shall be no visible leakage during the hold period. The final settling pressure shall not fall below the test pressure at the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.~~

~~Momentary pressure drops during the hold period due to sensitivity/noise in electronic data acquisition systems are permitted so long as the final pressure recorded is above the specified minimum test pressure and measurement devices have remained isolated from the pressure source throughout the entire hold period. If a pressure monitoring gauge and/or chart recorder is used for documentation purposes, the chart record may have a pressure settling rate not exceeding 3 % of the test pressure, or 300 psi (2 MPa) per 15 minutes, whichever is less.~~

~~For the secondary low-pressure seat test, the test pressure shall be 300 psi \pm 30 psi (2 MPa \pm 0.2 MPa) over the hold period.~~

~~Requirements for HPHT~~

~~When required by the manufacturer or user/purchaser, HPHT equipment shall be pressure tested in accordance with Annex D of this specification.~~

~~Hydraulic System Pressure Testing~~

~~Components that contain a hydraulic control fluid shall be tested to a hydrostatic body test at 1.5 times the hydraulic RWP of their respective hydraulic systems with primary and secondary hold times in accordance with 5.4, PSL 3. All operating subsystems (actuators, connectors, etc.) that are operated by the hydraulic system shall function at 0.9 times the hydraulic RWP or less of their respective system.~~

~~Where the hydraulic system does not communicate with the wellbore, the hydraulic system RWP shall be limited to the lowest rated hydraulic system pressure-containing element, as specified by the manufacturer. The hydrostatic test pressure of the hydraulic system shall be 1.5 times the hydraulic RWP with primary and secondary hold times in accordance with 5.4, PSL 3. The test medium is the hydraulic system fluid. Acceptance criterion shall be no visible leakage.~~

~~NOTE—Chart recording is not required.~~

~~Cathodic Protection~~

~~Electric continuity tests shall be performed to prove the effectiveness of the cathodic protection system. If the electrical continuity is not obtained, earth cabling shall be incorporated in the ineffective areas where the resistance is greater than 0.10 Ω .~~

~~Interface Testing~~

~~Where tooling can be affected by coating or insulation proximity, an interface check shall be performed after coating/insulation is applied to confirm that there is no loss or impairment to functionality of mating components or tooling, per manufacturer's written specification.~~

~~Equipment Marking~~

~~General~~

~~Equipment shall be marked with the following minimum information:~~

~~"API 17D";~~

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~~part number;~~

~~manufacturer name;~~

~~date of manufacture;~~

~~a unique identifier (serial number) for PSL 3 or PSL 3G equipment.~~

~~Equipment shall be marked in either metric units or U.S. customary units as applicable. The units shall be marked together with the numbers.~~

~~Marking on pressure-containing components shall be:~~

~~low-stress die-stamped (dot, vibration, or rounded V);~~

~~laser engraved.~~

~~NOTE—Marking information for pad eyes and lift points are identified in 5.5.2.~~

~~Pad Eyes and Lift Points~~

~~Pad eyes intended for lifting shall be painted red in accordance with API 17H and marked for lifting to alert personnel that safe handling can be made from this point. In addition, the documented MGW, sling lift angles from vertical, and the number of pad eyes used in the lift shall be marked adjacent to each lifting pad eye, and the overall MGW of the equipment assembly shall be marked on the equipment or framework. There shall only be one common unit of measure in the marking for MGW and individual lift pad eye load capacity.~~

~~EXAMPLE—A subsea assembly that has an MGW of 10,000 lb (4536 kg) with 4 pad eyes and designed for a 4-part sling lift at an angle of 30° (from vertical) is marked as:~~

~~4 × 2500 lb, 0–30°, adjacent to each lift pad eye,~~

~~and~~

~~MGW = 10,000 lb, in a visible position when it is in the operating position.~~

~~**Warning—Pad eyes on frames not painted red and/or properly labeled should be considered only as aids for handling lines (tag lines) or tie-down (e.g. transportation, sea fastening). Any pad eye or lift point not properly marked with lift marking should not be used for lifting. Lifting from unmarked pad eyes can lead to serious damage or injury.**~~

~~**Warning—Special attention should be paid to payload weights and their markings to ensure that the unit of measure for MGW matches rigging requirements.**~~

~~All packages exceeding 22,500 lb (100 kN) shall have pad eyes or other handling/tie-down provisions for handling and sea fastening. If pad eyes are used, they shall not be painted red and should be considered only as aids for handling lines (tag lines) or tie-down (transportation, sea fastening, etc.). All other equipment not suitable for shipping in baskets or containers shall be furnished with facilities for sea fastening.~~

~~Reusable Lifting Devices~~

~~Reusable lifting devices, such as tools, as determined in 5.1.3.7, or lift frames (such as lift subs, spreader bars, or strong-back beams), used for lifting shall be designed in accordance with 5.1.3.6, DNVGL-ST-E273, or regional lifting standard(s). Lift pad eyes shall be painted red and properly marked for lifting per 5.5.2 for its MGW and its designed lifting capacity of other equipment.~~

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~~All lift points and lift frames should be periodically inspected by competent/qualified personnel at defined inspection intervals.~~

~~Accommodation should be made in the design of the lift points and load paths to allow regular inspection, NDE, and/or load testing, if required. All repairs that include welding of the lift point or lifting load path shall require load testing and NDE after repair. The inspector shall decide if load testing/NDE following nonwelded repairs is required.~~

~~Storing and Shipping~~

~~Draining After Testing~~

~~All equipment shall be drained and lubricated in accordance with the manufacturer's written specification after testing and prior to storage or shipment.~~

~~Rust Prevention~~

~~Prior to shipment, parts and equipment shall have exposed metallic surfaces (except those otherwise designated such as anodes or nameplates) protected in accordance with API 6A.~~

~~Equipment already coated, but showing damage after testing, should undergo coating repair prior to storage or shipment as specified in 5.1.4.6.~~

~~Sealing Surface Protection~~

~~Exposed seals and seal surfaces, threads, and operating parts shall be protected from mechanical damage during shipping. Equipment or containers shall be designed such that equipment does not rest on any seal or seal surface during shipment or storage.~~

~~Loose Seals and Ring Gaskets~~

~~Loose seals, stab subs, and ring gaskets shall be individually boxed or wrapped for shipping and storage.~~

~~Elastomer Age Control~~

~~The manufacturer shall document instructions concerning the proper storage environment, age control procedures, and protection of elastomer materials. Loose or spare materials that are past their expiration date shall not be used on equipment. Hoses on equipment should be pressure tested to their RWP after extended storage periods, per the manufacturer's written specification.~~

~~Hydraulic Systems~~

~~Prior to shipment, the equipment including hydraulic lines shall be flushed and filled in accordance with the manufacturer's written specification. Exposed hydraulic end fittings shall be capped or covered. All pressure shall be bled from equipment, unless otherwise agreed between the manufacturer and the user/purchaser.~~

~~Electrical/Electronic Systems~~

~~The manufacturer shall document instructions concerning proper storage and shipping of all electrical cables, connectors, and electronic packages (pods).~~

~~Shipments~~

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~~For shipment of units and assemblies, the manufacturer shall maintain a documented procedure for securing and shipping equipment.~~

~~Assembly, Installation, and Maintenance Instructions~~

~~The manufacturer shall document instructions concerning field assembly, installation, and maintenance of equipment. These shall address safe operating procedures and practices.~~

~~Storage and Preservation~~

~~Storage and preservation requirements for equipment after delivery to the user/purchaser is beyond the scope of this specification. The manufacturer shall provide recommendations for storage to the user/purchaser upon request.~~

~~General Design Requirements for Subsea Tree Systems~~

~~General~~

~~Introduction~~

~~NOTE—Section 6 provides specific requirements for the equipment covered in Section 7 and Section 9. Subsea tree assembly configurations vary depending on wellhead type, service, well shut-in pressure, water depth, reservoir parameters, environmental factors, and operational requirements. As such, the subsea tree configuration requirements, including the location and quantity of USVs, are not specified in Section 6.~~

~~The number of potential leak paths should be minimized during system design.~~

~~Equipment that is used in the assembly of the subsea tree, but which is not covered in Section 6, Section 7, and Section 9, shall conform to the manufacturer's written specifications. The user/purchaser and manufacturer should agree on any additional requirements.~~

~~Handling and Installation~~

~~Structural analysis should be performed by the user/purchaser to ensure that structural failure does not occur at a point below the tree re-entry hub and that the tree can be left in a safe condition in the event of a drive-off before the tree running tool/emergency disconnect package (EDP) can be disconnected.~~

~~The subsea tree assembly, when lifted in the as-run condition, shall be balanced within 1.0° in air.~~

~~Orientation and Alignment~~

~~A tolerance and stack-up analysis shall be conducted to ensure that trees engage tubing hangers, wellheads, and guidebases; that tree running tools engage re-entry hubs; and that caps engage re-entry hubs. These studies shall include external influences, such as flowline forces, temperature, currents, riser offsets, etc. System tolerances should be defined to enable initial orientation and alignment while simultaneously avoiding seal and seal surface damage during landing, entering, mating, or disengagement of equipment packages. Where feasible during FAT, orientation and alignment should be confirmed by testing of interfaces that will be engaged remotely.~~

~~Rating~~

~~The PSL designation, pressure rating, temperature rating, and material class assigned to the subsea tree assembly shall be determined by the minimum rating of any single component used in the assembly of the subsea tree that is normally exposed to wellbore fluid.~~

Interchangeability

~~Components and subassemblies for different arrangements of subsea tree configurations should be interchangeable if functional requirements permit.~~

~~EXAMPLES—Change-out of tree connectors to suit different wellhead profiles, change-out of wing valve arrangements for different services, such as production, injection, etc., and the interchangeability of spares.~~

~~It is recommended that items that are engaged subsea have their interfaces confirmed using a mating item or fixture, especially when multiple units are being delivered separately. Manufacturers should define which parts are designed to be interchangeable.~~

Tubing Head and Tree Valving

Master Valves, Vertical Tree

~~Any valve in the vertical bore of the tree between the wellhead and the tree side outlet shall be defined as a master valve. A vertical subsea tree shall have one or more master valves in the vertical production (injection) bore and annulus access bore (when applicable). At least one valve in each bore shall be an actuated, fail-closed valve.~~

Master Valves, Horizontal Tree

~~The inboard valve branching horizontally off the tree between the tree body and tubing hanger and the production (injection) flow path (bore) shall be defined as the PMV. The inboard valve on the bore into the annulus below the tubing hanger shall be defined as the annulus master valve (AMV). A horizontal subsea tree shall have one or more master valves on each of the above bores. At least one valve in each of the above bores shall be an actuated, fail-closed valve.~~

Wing Valves, Vertical Tree

~~The side outlet for production (injection) shall have at least one wing valve. The annulus flow path of the subsea tree shall have at least one wing valve when a second AMV is not present.~~

Wing Valves, Horizontal Tree

~~The horizontal subsea tree shall have a wing valve downstream (upstream—injection) of the master valve in both the production (injection) flow path and the annulus flow path.~~

Crossover Valves

~~NOTE—A crossover valve (XOV) is an optional valve that, when opened, allows communication between the annulus and production tree paths, which are normally isolated. It can also be used for circulating completion fluids for an intervention system (see API 17G). For examples of valve placement, refer to Figures 1, 2, and 3.~~

Swab Closures, Vertical and Horizontal Tree

~~Any bore that passes through the subsea tree that can be used in workover operations shall be equipped with at least two barriers when the production outlet is below the entry to the bore and sealed when production is taken through the bore. In preparation for a workover and connection of the workover system, the bore shall be sealed by at least two barriers. Barriers may be caps, stabs, crown plugs, or valves. The removal or opening of the barriers shall not result in any diametrical restriction through the production bore of the tree or tubing hanger.~~

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~~Any valve performing the task of a swab valve, whether manual or actuated, shall be operable only via a workover control system (IWOCs as described in API 17G5) when actuated. During intervention operations, operable barriers may be either manual or actuated and when actuated shall only be operable by a workover control system.~~

~~Annulus access valve (AAV) or workover valve (WOV) may be considered forms of swab closures.~~

~~NOTE—Tree cap requirements are found in 7.12.~~

~~Horizontal Tree System Additional Access Requirements~~

~~An access port to the cavity between crown plugs shall be provided. Access to the TH gallery seal shall be provided.~~

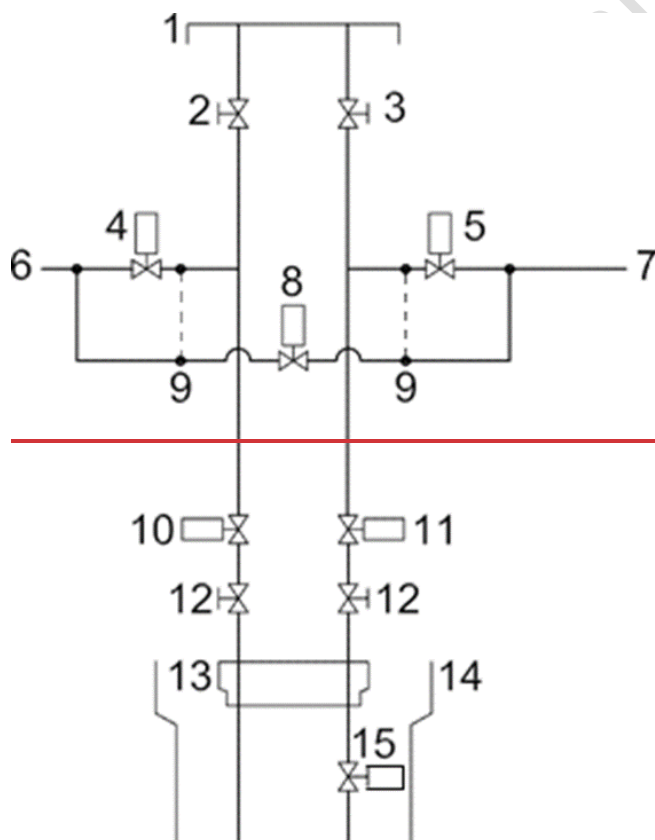
~~Production (Injection) and Annulus Flow Paths~~

~~Valving in the production (injection) and annulus flow paths shall include one actuated, fail-closed master valve in the production (injection) bore and one actuated, fail-closed master valve in the annulus bore.~~

~~Other valves as described in 6.2 may be added when required by legislation or project requirements with respect to operational/process and/or well intervention requirements.~~

~~The annulus flow path shall be designed to allow for the management of casing pressure in the production annulus with the ability to circulate during workover and well control situations.~~

~~NOTE—A schematic for a typical vertical dual-bore subsea tree is illustrated in Figure 1. Figure 2 illustrates vertical trees with tubing heads. Figure 3 illustrates horizontal subsea trees.~~



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Key

tree cap (swab closure) — 9 — optional crossover piping routing

annulus swab valve (ASV) (manual or fail closed or optional plug) — 10 — AMV

PSV (manual or fail closed or optional plug) — 11 — PMV

annulus wing valve (AWV) — 12 — optional lower master (manual or fail closed)

production wing valve (PWV) — 13 — tubing hanger

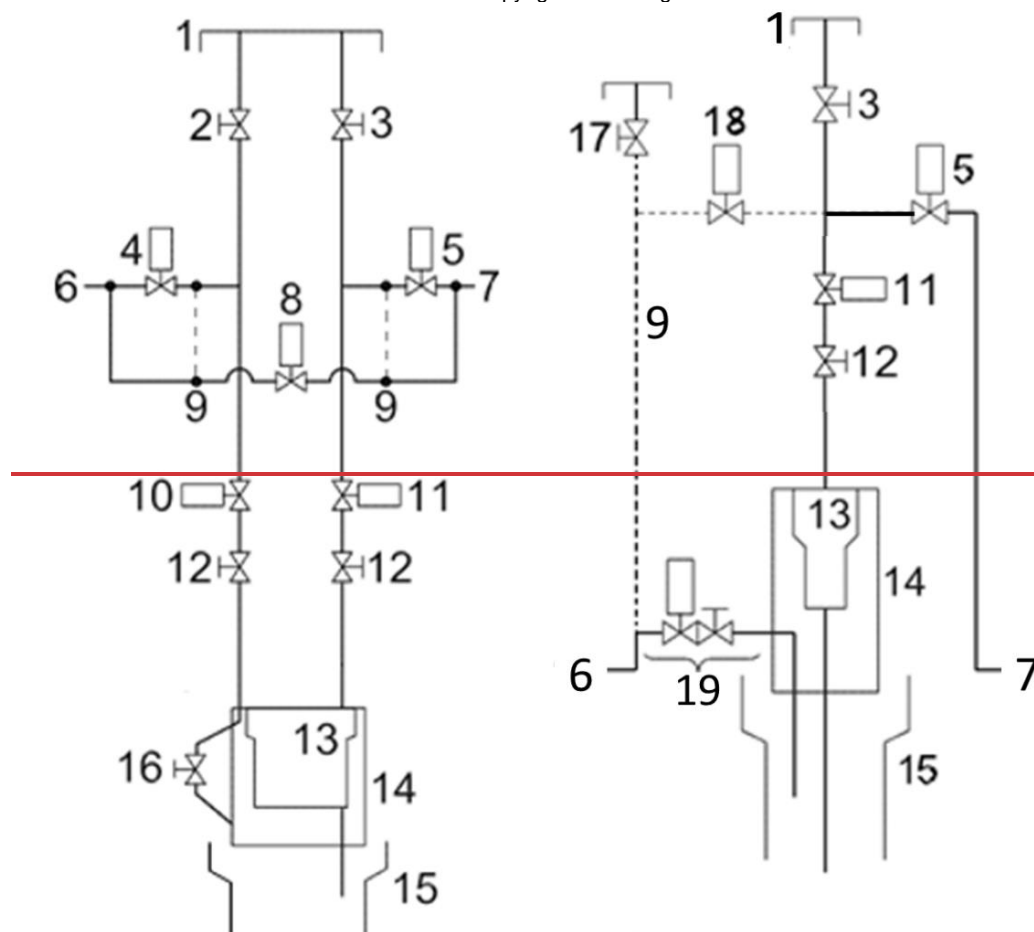
annulus (to umbilical line or service line) — 14 — subsea wellhead

production — 15 — SCSSV

XOV

NOTE The dotted inclusions are optional. A non-pressure containing tree cap can be considered when two swab closures are included.

Figure 1—Example of a Dual-bore Tree on a Subsea Wellhead

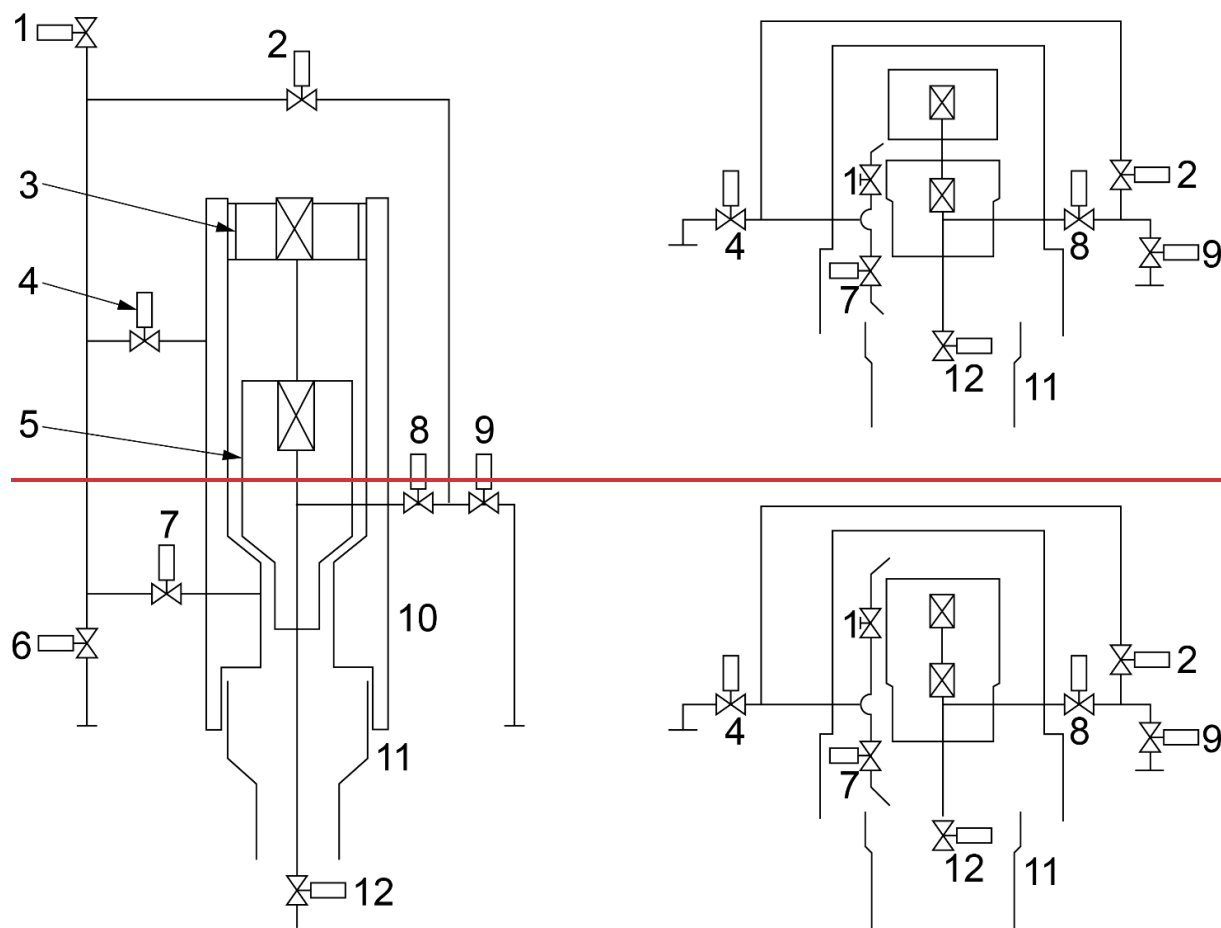


Key

- tree cap (swab closure) — 11 — PMV
- ASV (manual or fail-closed or optional plug) — 12 — optional lower master (manual or fail-closed)
- PSV (manual or fail-closed or optional plug) — 13 — tubing hanger
- AWV — 14 — tubing head
- PWV — 15 — subsea wellhead
- annulus (to umbilical line or service line) — 16 — annulus isolation valve (AIV)
- production — 17 — optional ASV (WOV or AAV) (manual or fail-closed)
- XOV — 18 — optional XO
- optional crossover piping routing — 19 — annulus valves (manual and fail-closed or both fail-closed)
- AMV —

NOTE The dotted inclusions are optional. A non-pressure-containing tree cap can be considered when two swab closures are included.

Figure 2—Example of Vertical Trees on Tubing Heads



Key

ASV (WOV or AAV) (manual or fail closed) — 7 — AMV

XOV — 8 — PMV

tree cap — 9 — PWV

AWV — 10 — tree body

tubing hanger — 11 — subsea wellhead

optional AWV — 12 — SCSSV

Figure 3—Examples of Horizontal Trees

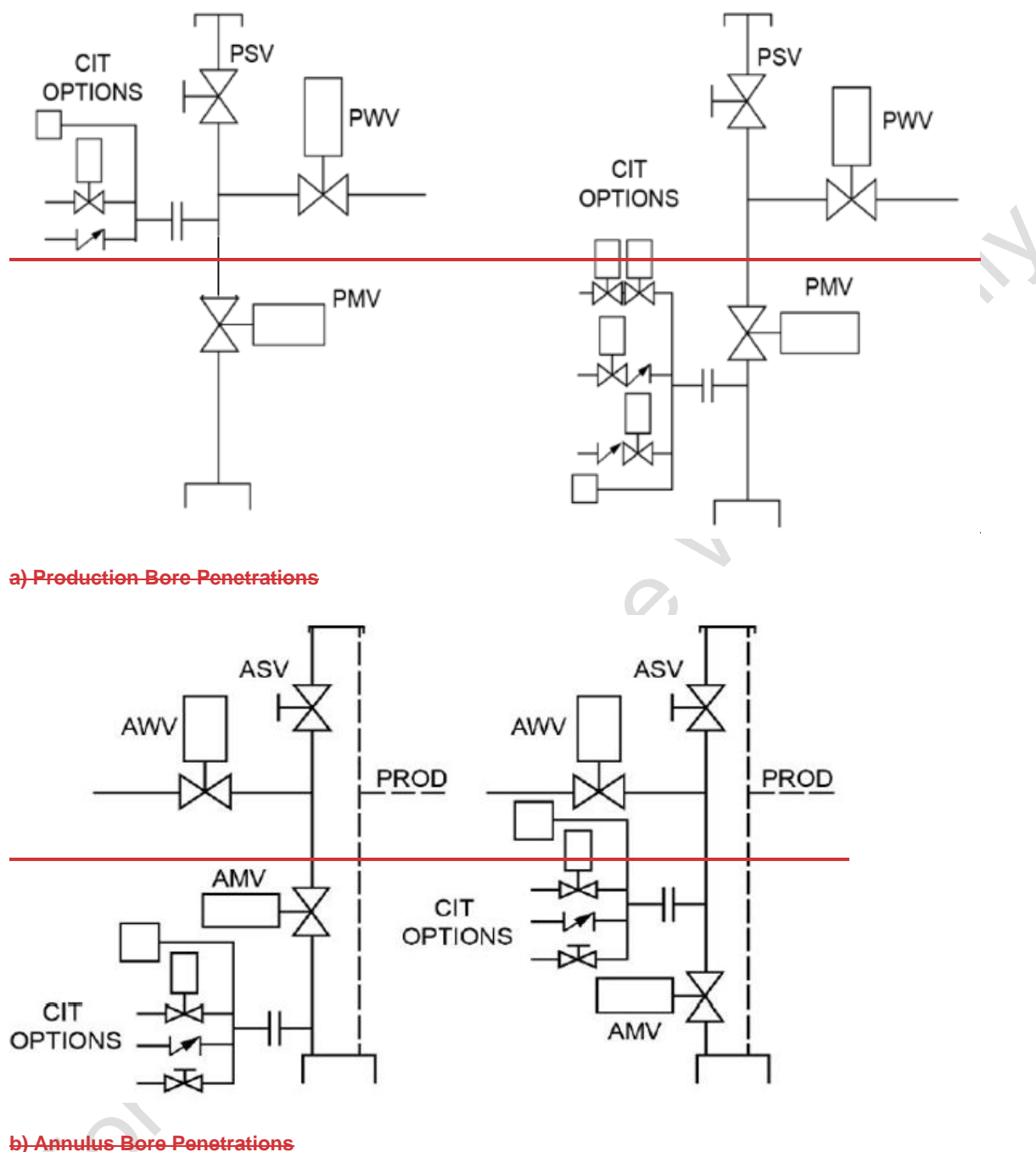


Figure 4—Examples of Bore Penetrations

Production and Annulus Bore Penetrations

There shall be at least two fail-closed pressure closures, one of which shall be an actuated, fail-closed valve, for any penetration leading into the production path of the tree or tubing head.

~~The master valve may be used as one of the barriers for conduit penetrations downstream of the master valve.~~

~~There shall be at least one testable pressure closure between the wellhead and any penetration leading into the annulus path of the tree or tubing head.~~

~~Sealed sensor devices with two or more pressure-containing sealing barriers may be directly attached to the penetration without additional barrier devices. Sealed sensor devices shall have the same or higher RWP as the tree or tubing head body to which it is connected.~~

~~All wellbore penetrations inboard of the wing valve shall have isolation means within the block and/or bolted to the block.~~

~~Flanges, clamp hubs, or other end connection, as applicable, meeting the requirements of Section 7 shall be used to provide connections for the penetrations to the tree or tubing head.~~

~~NOTE Figure 4 illustrates typical configurations that meet the requirements of this section.~~

SCSSV Control Line Penetrations

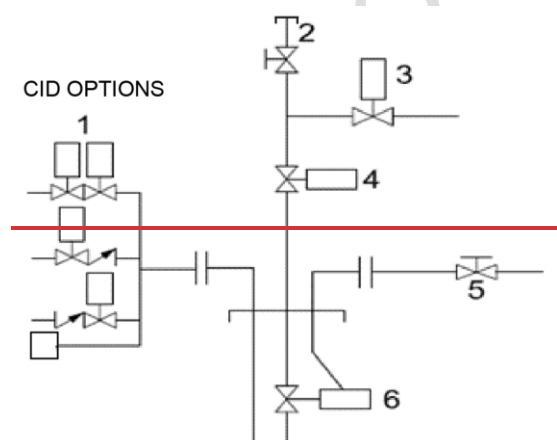
~~At least one pressure-controlling closure shall be used at all SCSSV control line penetrations that pass through either the tree or tubing head.~~

~~NOTE 1 Manual valves (diver/ROV operated) are acceptable closure devices.~~

~~Any remotely operated closure device, including control line couplers that are designed to prevent the ingress of seawater, used in the SCSSV control line circuit shall be designed such that it does not interfere with the closure of the SCSSV. Connections threaded directly into a tree body or wing valve block for SCSSV control line penetrations are prohibited.~~

~~Check valves shall not be used anywhere in the SCSSV circuit if their closure can prevent venting down of the control pressure.~~

~~NOTE 2 Figure 5 illustrates typical subsea tree valving for SCSSV circuits that meet the requirements of this section.~~



Key

1 — CID options

4 — PMV

2 — PSV

5 — SCSSV isolation

3 — PWW

6 — SCSSV

NOTE — The SCSSV line is designed to prevent hydraulic lock open of SCSSV when it is disconnected.

Figure 5—Examples of Tree Valving for Downhole Chemical Injection and SCSSV

Downhole Chemical Injection Line Penetrations

Two fail-closed barriers (e.g. check valves or actuated valves) shall be included for all chemical injection lines that pass through the tubing hanger. At least one of the valves shall be an actuated, fail-closed valve.

Flow-closed check valves may be used as one of the fail-closed valves, for lines with a diameter of 1.00 in. (25.4 mm) or smaller.

The left side of Figure 5 illustrates typical subsea tree valving for the above. The check valve may be inboard or outboard of the fail-closed valve.

Flanges, clamp hubs, or OECs, as applicable, meeting the requirements of Section 7 shall be used to provide connections for the penetrations to the tree.

Threaded connections going directly into a tree body or wing-valve block for chemical injection penetrations shall not be used when inboard of the two closure devices.

Pressure Monitoring/Test Lines and Internal Control Lines

At least one pressure-controlling closure shall be used on all pressure-monitoring/test internal control lines and passages (that pass into or through either the tree or tubing head).

The RWP of any hydraulic control line that has the potential for wellbore communication shall be equal to or greater than the RWP of the tree.

Threaded connections going directly into a tree body or wing-valve block for pressure monitoring/test line penetrations shall not be used when inboard of the closure device.

NOTE — On lines such as connector cavity test lines, manual isolation valves are acceptable closure devices.

Compensating Barrier

Where a compensating barrier is used to exclude seawater from the actuator and to balance external pressure, it shall be sized to accommodate a minimum of 120 % of the swept volume. A means, such as check valves, should be included in the circuit to prevent hydraulic lock. A relief device shall be included in this circuit to eliminate the chance that the failure of an actuator seal can affect the performance of the remaining valves. The manufacturer shall document the compensation fill procedure.

Downhole Hydraulic Control Line Penetrations for Intelligent Well Completions

At least one pressure-controlling closure shall be used in all hydraulic control lines that penetrate through the tree and tubing head and that are used to operate downhole, intelligent, well completion systems.

Closure devices shall be manual or fail-closed isolation valves for an intelligent well control system that is operated remotely through the production control umbilical.

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~~Closure devices should always be maintained in the closed position except while the intelligent well control system is being operated. When a control pod is used to operate the intelligent well control system, the intelligent well control functions shall be vented through a hydraulic circuit other than the one(s) used to vent fluid/pressure from other control functions on the tree, including the SCSSV.~~

~~Flanges, clamp hubs, or OECs, as applicable, meeting the requirements of Section 7 shall be used to provide connections for the intelligent well control penetrations to the tree. Threaded connections going directly into a tree body or wing-valve block for intelligent well control line penetrations are prohibited.~~

~~Thermal expansion of the hydraulic fluid in the intelligent well control lines should be addressed in the design and operation of the intelligent well control system.~~

~~Thermally Induced Pressure Changes~~

~~Pressure integrity shall not be compromised due to thermally induced pressure changes in trapped volumes. A trapped volume analysis shall account for the various fluid properties contained.~~

~~Testing of Subsea Tree Assemblies~~

~~Validation~~

~~NOTE—There are no validation requirements at the assembly level for subsea trees. Validation of various tree components are covered in 5.1.7.~~

~~Factory Acceptance Testing~~

~~The subsea tree assembly shall be factory acceptance tested in accordance with the manufacturer's written specification using the actual mating equipment or an appropriate test fixture that simulates the applicable interfaces [CGB, permanent guidebase (PGB), guidelineless re-entry assembly (GRA), tree frame, etc.), wellhead, and tubing hanger interfaces.]~~

~~The subsea tree assembly shall be pressure tested to 1.0X RWP. Refer to 7.16.2.6 for pressure test requirements for inboard and outboard piping.~~

~~NOTE 1—See Section 5 for testing requirements.~~

~~NOTE 2—Because of the different subsea tree configurations, components can be directly exposed to wellbore fluid in some instances or serve as a second barrier in others. Table 6 is provided as a pictorial representation to clarify where the components are located and what hydrostatic test pressures are required with respect to body, interface, and lockdown retention testing. Detailed test requirements for each element/location are described in the applicable sections within this specification.~~

~~Marking~~

~~The subsea tree assembly shall be marked in accordance with 5.5.1.~~

~~Storing and Shipping~~

~~Any disassembly, removal, or replacement of parts or equipment after FAT shall be as agreed with the user/purchaser.~~

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Table 6—Pressure Test Pictorial Representations

a) Vertical Subsea Tree				
Position	Description	RWP	Hydrostatic Pressure	Body Test Pressure
A	Subsea wellhead	1.0 × RWP	1.5 × RWP	NA
B	Tubing head connector, tubing head, and tree connector	1.0 × RWP	1.5 × RWP	NA
C	Valves, valve block	1.0 × RWP	1.5 × RWP	NA
D	Downhole flow passages and seal subs (SCSSV, other hydraulic, injection)	1.0 × [RWP + up to 2500 psi (17.2 MPa)]	1.5 × RWP	NA
	Downhole flow passages and seal subs (SCSSV, other hydraulic, injection)	1.0 × [RWP + up to 2500 psi (17.2 MPa)]	1.0 × [RWP + up to 2500 psi (17.2 MPa)]	NA
E	Tree cap (flow passages below tree cap and lock mechanism)	1.0 × RWP	1.5 × RWP	NA
F	Tubing hanger	1.0 × RWP	1.5 × RWP	NA
L1	Below installed tubing hanger	NA	NA	1.1 × RWP
L2	Above tubing hanger plug	NA	NA	1.0 × RWP
(not shown)	Below tubing hanger plug	NA	NA	1.1 × RWP
L3	Gallery	1.0 × [RWP + up to 2500 psi (17.2 MPa)]	NA	NA

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Table 6—Pressure Test Pictorial Representations (continued)

b) Horizontal Subsea Tree with Separate Internal Tree Cap				
Position	Description	RWP	Hydrostatic Body Test Pressure	Lockdown Retention Test Pressure
A	Subsea wellhead	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
B	Tree connector	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
C	Valves, valve block	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
D	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-containing)	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	$1.5 \times \text{RWP}$	NA
	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-controlling)	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	NA
E	Debris cap	PMR	PMR	NA
F	Crown plugs	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
G	Internal tree cap	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
H	Tubing hanger	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
L1	Below installed tubing hanger	NA	NA	$1.5 \times \text{RWP}$
L2	Below internal tree cap	NA	NA	$1.5 \times \text{RWP}$
L3	Above lower crown plug	NA	NA	$1.0 \times \text{RWP}$
	Below lower crown plug	NA	NA	$1.5 \times \text{RWP}$
L4	Above upper crown plug	NA	NA	$1.0 \times \text{RWP}$
	Below upper crown plug ^a	NA	NA	$1.5 \times \text{RWP}$
L5	Gallery	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	NA	NA

^a — If a lower crown plug is in place during the upper-crown-plug test from below, then the lower crown plug shall be pressure-equalized from above and below the lower crown plug during the test.

Table 6—Pressure Test Pictorial Representations (continued)

c) Horizontal Subsea Tree without Separate Internal Tree Cap				
Position	Description	RWP	Hydrostatic Pressure	Body Test Lockdown-Retention Test Pressure
A	Subsea wellhead	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
B	Tree connector	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
C	Valves, valve block	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
D	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-containing)	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	$1.5 \times \text{RWP}$	NA
	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-controlling)	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ psi (17.2 MPa)}]$	NA
E	Debris cap	PMR	PMR	NA
F	Crown plugs	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
G	ROV tree cap	PMR	PMR	NA
H	Tubing hanger	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
L1	Below installed tubing hanger	NA	NA	$1.5 \times \text{RWP}$
L2	Above lower crown plug	NA	NA	$1.0 \times \text{RWP}$
	Below lower crown plug	NA	NA	$1.5 \times \text{RWP}$
L3	Above upper crown plug	NA	NA	$1.0 \times \text{RWP}$
	Below upper crown plug ^a	NA	NA	$1.5 \times \text{RWP}$

L4	Gallery	$1.0 \times [\text{RWP} + \text{up to } 2500 \text{ NA psi (17.2 MPa)}]$	NA
a — If a lower crown plug is in place during the upper crown plug test from below, then the lower crown plug shall be pressure-equalized from above and below the lower crown plug during the test.			

Specific Requirements—Subsea Tree-related Equipment and Subassemblies

Flanged End and Outlet Connections

General—Flange Types

NOTE 1 — Section 7 specifies the API type end and outlet flanges used on subsea completion equipment. Table 7 lists the types and sizes of flanges covered by this specification.

Table 7—Rated Working Pressures and Size Ranges of API Flanges

Rated Working Pressure		Flange Size Range					
		Type 17SS		Type 17SV		Type 6BX	
psi	(MPa)	in.	(mm)	in.	(mm)	in.	(mm)
5000	(34.5)	$2\frac{1}{16}$ to $13\frac{5}{8}$	(52 to 346)	$2\frac{1}{16}$ to $13\frac{5}{8}$	(52 to 346)	$13\frac{5}{8}$ to $21\frac{1}{4}$	(346 to 540)
10,000	(69.0)	—	—	$1\frac{13}{16}$ to $13\frac{5}{8}$	(46 to 346)	$1\frac{13}{16}$ to $21\frac{1}{4}$	(46 to 540)
15,000	(103.5)	—	—	—	—	$1\frac{13}{16}$ to $18\frac{3}{4}$	(46 to 496)

Standard flanges for subsea completion equipment with working pressures of 5000 psi (34.5 MPa) in sizes of $2\frac{1}{16}$ in. (52 mm) through $13\frac{5}{8}$ in. (346 mm) shall be type 17SS flanges as defined in 7.1.2.2. Type 17SS flanges shall conform to Table 7, Table 9, Table 10, and Table 11.

Standard flanges for 5000 psi (34.5 MPa) in sizes of $13\frac{5}{8}$ in. (346 mm) through $21\frac{1}{4}$ in. (540 mm) shall be type 6BX flanges as defined in API 6A.

Standard flanges for subsea completions with maximum working pressures of 10,000 psi (69 MPa) or 15,000 psi (103.5 MPa) shall be type 6BX flanges as defined in API 6A. API-type flanges for subsea completions may be either integral, blind, or welding neck flanges. Threaded flanges, as defined in API 6A, shall not be used on subsea completion equipment handling produced fluids, except as specified in 7.3.

Segmented flanges shall not be used.

NOTE 2 — Swivel flanges are often used to facilitate subsea flowline connections that are made up underwater. Type 17SV flanges, as defined herein, have been developed as the standard swivel flange design for subsea completions in the sizes and working pressures given in Table 7. Type 17SV swivel flanges are designed to mate with standard API-type 17SS and type 6BX flanges of the same size and pressure rating.

Design

General

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~~All flanges used on subsea completion equipment shall be of the ring-joint type designed for face-to-face make-up. The connection make-up force and external loads shall react primarily on the raised face of the flange. Therefore, at least one of the flanges in a connection shall have a raised face.~~

~~All flanged connections that are made up underwater in accordance with the manufacturer's written specification shall be equipped with a means to vent any trapped fluids. Type SBX ring gaskets, as shown in Table 8, are an acceptable means for venting type 6BX, 17SS, or 17SV flanges. Type SBX or API 6A-type BX ring gaskets are acceptable for 6BX, 17SS, or 17SV flanges made up in air.~~

~~Other proprietary flange and seal designs that eliminate the trapped fluid problem have been developed and these are, therefore, well suited for underwater make-up. These proprietary flange and seal designs shall conform to 7.4.~~

~~Trapped fluid may interfere with the proper make-up of padstuds or bolts installed in blind holes underwater. If installed underwater, a means should be provided to confirm that bolting has been fully engaged in the blind hole or a means to vent trapped fluid from behind the installed bolting.~~

Ring Gaskets

~~Types 6BX, 17SS, and 17SV flanges in subsea completion equipment shall use types BX or SBX gaskets. If these flanges are made up underwater, they shall be made up with SBX gaskets, in accordance with 7.1.2.1.~~

~~Connections that are not made up underwater may use nonvented type BX gaskets.~~

~~Gasket material shall be of a corrosion-resistant alloy (CRA) or corrosion-resistant material (CRM) to provide corrosion resistance to seawater under the specified operating conditions (dissimilar metal corrosion with the ring groove). Gasket materials shall conform to the requirements of API 6A.~~

~~The thickness of coatings and platings used on BX and SBX ring gaskets to aid seal engagement while minimizing galling shall not exceed 0.0005 in. (0.013 mm). The use of coatings that can be harmful to the environment or galvanically active should be avoided. Local legislation should be checked for coatings deemed hazardous.~~

~~Proprietary gaskets shall conform to the manufacturer's written specification.~~

~~Grease shall not be applied around the complete perimeter to hold ring gaskets in position during make-up, since grease can interfere with proper make-up of the gasket. Tack welding rods to the OD of seal rings (to simplify positioning of the ring during make-up) shall not be used on gaskets for subsea service.~~

~~Except for testing purposes, BX and SBX ring gaskets shall not be reused.~~

~~Marking of ring gaskets shall be on the outside diameter of the gasket and include the following information:~~

~~date of manufacture;~~

~~manufacturer's name or trademark;~~

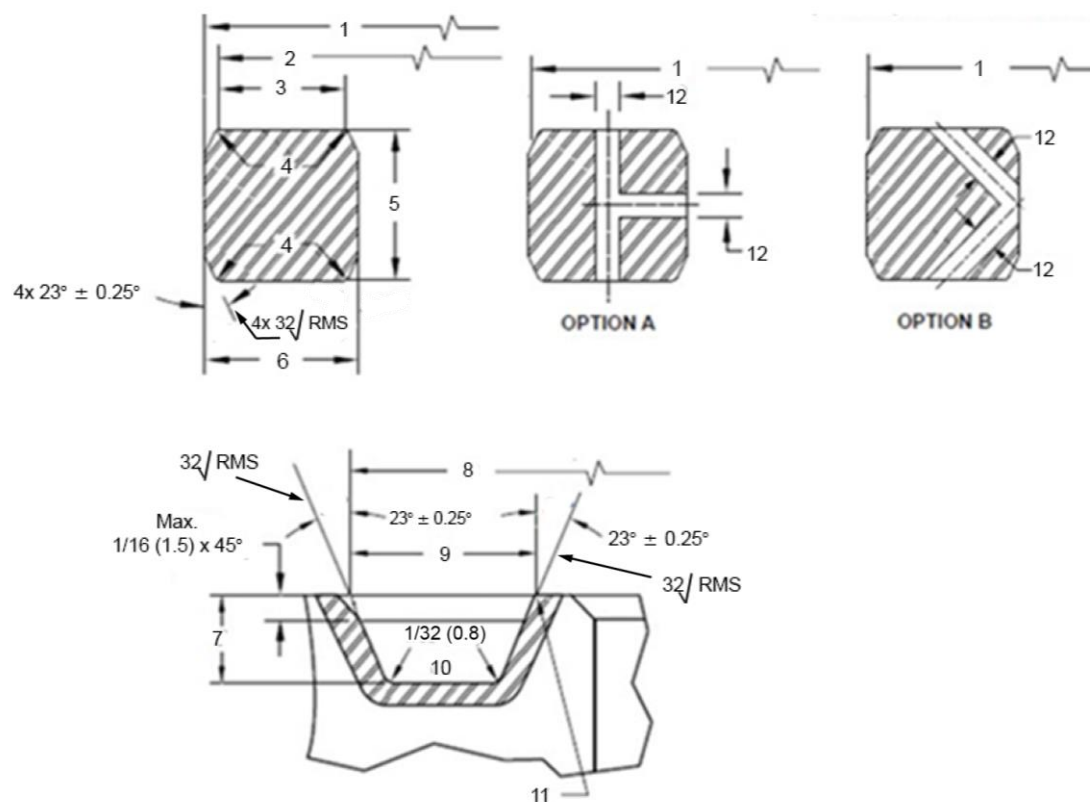
~~ring gasket type (BX, SBX) and number;~~

~~ring gasket material code per API 6A.~~

~~Table 8 API type SBX Pressure energized Ring Gaskets~~

Key

1	OD, outer diameter of ring	$+0 \begin{pmatrix} +0 \\ -0.006 \end{pmatrix} \begin{pmatrix} +0 \\ -0.15 \end{pmatrix}$
2	ODT, outside diameter T	$\pm 0.002 \text{ } (\pm 0.05)$
3	C width of flat	$+0.006 \begin{pmatrix} +0.15 \\ 0 \end{pmatrix}$
4	R_1 radius in ring	See NOTE 1
5	H^a height of ring	$+0.008 \begin{pmatrix} +0.2 \\ 0 \end{pmatrix}$
6	A^a width of ring	$+0.008 \begin{pmatrix} +0.2 \\ 0 \end{pmatrix}$
7	E depth of groove	$+0.02, -0 \text{ } (+0.5, -0)$
8	G outside diameter of groove	$+0.004, -0 \text{ } (+0.1, -0)$
9	N width of groove	$+0.004, -0 \text{ } (+0.1, -0)$
10	R_2 radius in groove	max.
11	Break sharp corner	
12	D hole diameter	$\pm 0.02 \text{ } (\pm 0.05)$



~~NOTE 1 Radius R shall be 8 % to 12 % of the gasket height, H .~~

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NOTE 2 Two pressure passage holes in the SBX ring cross section prevent pressure lock when connections are made up underwater. Two options are provided for drilling the pressure passage holes.

Table 8—API type SBX Pressure-energized Ring Gaskets (*continued*)

Ring No.	Size		Outside Diameter of Ring		Height of Ring ^a		Width of Ring ^a		Diameter of Flat		Width of Flat		Hole Size		Depth of Groove		Outside Diameter of Groove		Width of Groove	
			OD		H		A		OD _F		C		D		E		G		A ₁	
	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)
SBX-149	3/4	(19)	1.679	(42.647)	0.379	(9.627)	0.296	(7.518)	1.627	(41.326)	0.241	(6.121)	0.06	(1.5)	0.23	(5.842)	1.741	(44.221)	0.381	(9.677)
SBX-150	1	(25)	2.842	(72.19)	0.366	(9.30)	0.366	(9.30)	2.790	(70.87)	0.314	(7.98)	0.06	(1.5)	0.22	(5.56)	2.893	(73.48)	0.450	(11.43)
SBX-151	1-13/16	3.008	(76.40)	0.379	(9.63)	0.379	(9.63)	2.954	(75.03)	0.325	(8.26)	0.06	(1.5)	0.22	(5.59)	3.062	(77.77)	0.466	(11.84)	1-13/16
SBX-152	2-1/16	3.334	(84.68)	0.403	(10.24)	0.403	(10.24)	3.277	(83.24)	0.346	(8.79)	0.06	(1.5)	0.23	(5.95)	3.0395	(86.23)	0.498	(12.65)	2-1/16
SBX-153	2-9/16	3.974	(100.94)	0.448	(11.38)	0.448	(11.38)	3.910	(99.31)	0.385	(9.78)	0.06	(1.5)	0.27	(6.75)	4.046	(102.77)	0.554	(14.07)	2-9/16
SBX-154	3-1/16	4.600	(116.84)	0.488	(12.40)	0.488	(12.40)	4.531	(115.09)	0.419	(10.64)	0.06	(1.5)	0.30	(7.54)	4.685	(119.00)	0.606	(15.39)	3-1/16
SBX-155	4-1/16	5.825	(147.96)	0.560	(14.22)	0.560	(14.22)	5.746	(145.95)	0.481	(12.22)	0.06	(1.5)	0.33	(8.33)	5.930	(150.62)	0.698	(17.73)	4-1/16
SBX-156	7-1/16	9.367	(237.92)	0.733	(18.62)	0.733	(18.62)	9.263	(235.28)	0.629	(15.98)	0.12	(3.0)	0.44	(11.11)	9.521	(241.83)	0.921	(23.39)	7-1/16
SBX-157	9	11.593	(294.46)	0.826	(20.98)	0.826	(20.98)	11.476	(291.49)	0.709	(18.01)	0.12	(3.0)	0.50	(12.70)	11.774	(299.06)	1.039	(26.39)	9
SBX-158	11	13.860	(352.04)	0.911	(23.14)	0.911	(23.14)	13.731	(348.77)	0.782	(19.86)	0.12	(3.0)	0.56	(14.29)	14.064	(357.23)	1.149	(29.18)	11
SBX-159	13-5/8	16.800	(426.72)	1.012	(25.70)	1.012	(25.70)	16.657	(423.09)	0.869	(22.07)	0.12	(3.0)	0.62	(15.88)	17.033	(432.64)	1.279	(32.49)	13-5/8
SBX-160	13-5/8	16.850	(402.59)	0.938	(23.83)	0.541	(13.74)	16.717	(399.21)	0.408	(10.36)	0.12	(3.0)	0.56	(14.29)	16.063	(408.00)	0.786	(19.96)	13-5/8
SBX-161	16-3/4	19.347	(491.41)	1.105	(28.07)	0.638	(16.21)	19.191	(487.45)	0.482	(12.24)	0.12	(3.0)	0.67	(17.07)	19.604	(497.94)	0.930	(23.62)	16-3/4
SBX-162	16-3/4	18.720	(475.49)	0.560	(14.22)	0.560	(14.22)	18.641	(473.48)	0.481	(12.22)	0.06	(1.5)	0.33	(8.33)	18.832	(487.33)	0.705	(17.91)	16-3/4
SBX-163	18-3/4	21.896	(556.16)	1.185	(30.10)	0.684	(17.37)	21.728	(551.89)	0.516	(13.11)	0.12	(3.0)	0.72	(18.26)	22.185	(563.50)	1.006	(25.55)	18-3/4
SBX-164	18-3/4	22.463	(570.56)	1.185	(30.10)	0.968	(24.59)	22.295	(566.29)	0.800	(20.32)	0.12	(3.0)	0.72	(18.26)	22.752	(577.90)	1.290	(32.77)	18-3/4
SBX-165	21-1/4	24.595	(624.71)	1.261	(32.03)	0.728	(18.49)	24.417	(620.19)	0.550	(13.97)	0.12	(3.0)	0.75	(19.05)	24.904	(632.56)	1.071	(27.20)	21-1/4
SBX-166	21-1/4	25.198	(640.03)	1.261	(32.03)	1.029	(26.14)	25.020	(635.51)	0.851	(21.62)	0.12	(3.0)	0.75	(19.05)	25.507	(647.88)	1.373	(34.87)	21-1/4
SBX-169	5-1/8	6.831	(173.51)	0.624	(15.85)	0.509	(12.93)	6.743	(171.27)	0.421	(10.69)	0.06	(1.5)	0.38	(9.62)	6.955	(176.66)	0.666	(16.92)	5-1/8

^a——A plus tolerance of 0.008 in. (0.2 mm) for width, A, and height, H, is permitted, provided the variation in width or height of any ring does not exceed 0.004 in. (0.1 mm) throughout its entire circumference.

Corrosion-resistant Ring Grooves

~~All end and outlet flanges, and flanged connections used on subsea completion equipment shall be manufactured from a CRA, or their ring grooves overlaid with a CRM/CRA material, per 5.3.3, to provide corrosion resistance to seawater under the specified operating conditions.~~

~~Prior to application of the overlay, preparation of the BX ring grooves shall conform to the dimensions in Table 12 or API 6A. The overlay material shall be compatible, in accordance with the manufacturer's written specification, with retained fluids and with both the base metal of the flange and the gasket material (surface hardness, galling, and dissimilar metals corrosion).~~

~~Standard Subsea Flanges—Type 6BX with Working Pressures of 10,000 psi (69 MPa) or 15,000 psi (103.5 MPa)~~

~~Standard flanges for subsea completion equipment with a working pressure of 10,000 psi (69 MPa) or 15,000 psi (103.5 MPa) shall conform to the requirements for type 6BX flanges, as defined in API 6A. These flanges are ring-joint-type flanges, designed for face-to-face make-up. The connection make-up force and external loads shall react primarily on the raised face of the flange.~~

~~Corrosion-resistant, inlaid ring grooves for type 6BX flanges shall conform to the requirements of API 6A.~~

~~Special Purpose Subsea Flanges—Type 17SS with Working Pressures of 15,000 psi (103.5 MPa) or 17,500 psi (120.7 MPa)~~

~~Special purpose 1 in. (25 mm) flanges for use with a working pressure of 15,000 psi (103.5 MPa) or 0.75 in. (19 mm) flanges for use with a working pressure of 17,500 psi (120.7 MPa) for subsea completion equipment shall conform to the requirements for type 6BX flanges, as defined in Table 10.~~

~~Standard Subsea Flanges—Type 17SS with Working Pressures of 5000 psi (34.5 MPa)~~

General

~~2¹/₁₆ in. (52 mm) through 11 in. (279 mm) type 17SS flange designs are based on type 6B flange designs as defined in API 6A, but they have been modified to incorporate type BX ring gaskets (the established practice for subsea completions) rather than type R or RX gaskets. In addition, type 17SS flanges shall be designed with raised faces for rigid face-to-face make-up.~~

~~5000 psi (34.5 MPa) type 17SS flanges shall be used for all 2¹/₁₆ in. (52 mm) through 11 in. (279 mm) subsea completion API type flange applications at or below 5000 psi (34.5 MPa) working pressure.~~

~~13⁵/₈ in. (346 mm) through 21¹/₄ in. (540 mm) standard subsea flanges for working pressures of 5000 psi (34.5 MPa) and below shall be type 6BX flanges as defined in API 6A.~~

Dimensions

Standard Dimensions

~~Dimensions for type 17SS flanges shall conform to Figure 6 and Table 9, Table 10, and Table 11. Dimensions for ring grooves shall conform to Table 8 through Table 12 or API 6A.~~

~~Type 17SS flanges used as end connections on subsea completion equipment may have entrance bevels, counterbores or recesses to receive running/test tools, plugs, etc. The dimensions of counterbores and recesses are not covered by this specification but shall not exceed the *B* dimension given in Table 9 and Table 10.~~

Integral Flange Exceptions

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~~The manufacturer shall ensure that the modified integral flange designs shall meet the requirements of Section 5.~~

~~Welding Neck Flanges—Line Pipe~~

~~The following conditions shall apply.~~

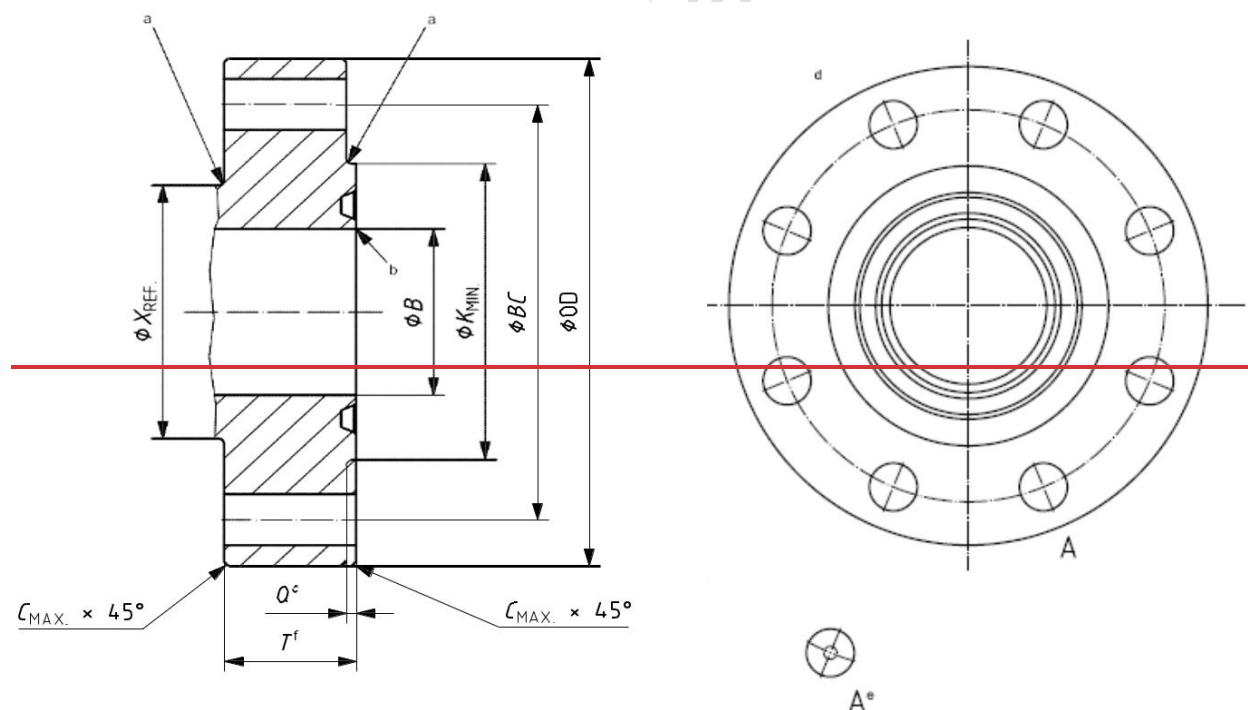
~~Bore and wall thickness—The bore diameter, J_L , shall not exceed the values given in Table 11. The specified bore shall not result in a weld end wall thickness less than 87.5 % of the wall thickness of the pipe to which the flange is being attached.~~

~~Weld end preparation—Dimensions for weld end preparation shall conform to Figure 8.~~

~~Taper—When the thickness at the welding end is at least 0.09 in. (2.3 mm) greater than that of the pipe and the additional thickness decreases the inside diameter (ID), the flange shall be taper-bored from the weld end at a slope not exceeding 3 to 1.~~

~~NOTE—It is not intended in this specification that Type 17SS welding neck flanges be welded to wellheads or tree bodies. Their purpose is to provide a welding transition between a flange and a pipe.~~

~~Table 9—Basic Flange and Bolt Dimensions for Type 17SS Flanges for 5000 psi (34.5 MPa) Rated Working Pressure~~



~~Key~~

~~0.12 in. (3 mm) minimum R .~~

~~Break sharp corners.~~

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~~$\phi = 0.18 \text{ in. (4.6 mm)} \pm 0.06 \text{ in. (1.5 mm)}$~~

~~Ring groove shall be concentric with bore within 0.010 in. (0.3 mm) total indicator runout.~~

~~Bolt hold centerline located within 0.03 in. (0.8 mm) of theoretical BC and bolt holes with equal spacing.~~

~~$0.12 \begin{pmatrix} +3 \\ 0 \end{pmatrix}$~~

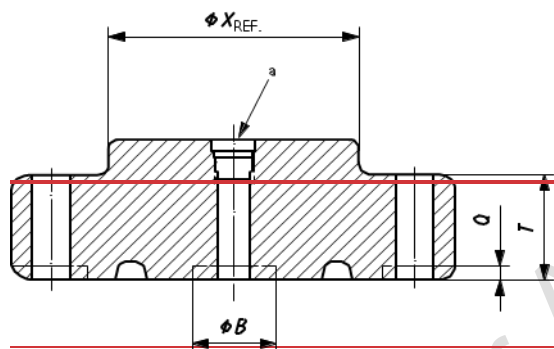
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Table 9—Basic Flange and Bolt Dimensions for Type 17SS Flanges for 5000 psi (34.5 MPa) Rated Working Pressure (continued)

Basic Flange Dimensions												Bolt Dimensions															
Nominal Size and Bore of Flange		Maximum Bore		Outside Diameter of Flange		Tolerance on OD		Maximum Chamfer		Diameter of Raised Face		Total Thickness of Flange		Diameter of Hub		Diameter of Bolt Circle		No. of Bolts	Diameter of Bolts		Diameter of Bolt Holes		Bolt Hole Tolerance ^a		Length of Stud Bolts		BX Ring No.
in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)		in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	
2 ¹ / ₁₆	(52)	2.09	(53.1)	8.50	(215)	±0.06	(±2)	0.12	(3)	5.03	(128)	1.84	(46.0)	4.12	(104.7)	6.50	(165.1)	8	7/ ₈	(22)	1.00	(26)	+0.06	(2)	6.00	(155)	152
2 ⁹ / ₁₆	(65)	2.59	(65.8)	9.62	(245)	±0.06	(±2)	0.12	(3)	5.78	(147)	1.94	(49.3)	4.88	(124.0)	7.50	(190.5)	8	1	(25)	1.12	(29)	+0.06	(2)	6.50	(165)	153
3 ¹ / ₈	(78)	3.15	(80.0)	10.50	(265)	±0.06	(±2)	0.12	(3)	6.34	(160)	2.19	(55.7)	5.25	(133.4)	8.00	(203.2)	8	1 ¹ / ₈	(29)	1.25	(32)	+0.06	(2)	7.25	(185)	154
4 ¹ / ₁₆	(103)	4.09	(103.9)	12.25	(310)	±0.06	(±2)	0.12	(3)	7.63	(194)	2.44	(62.0)	6.38	(162.1)	9.50	(241.3)	8	1 ¹ / ₄	(32)	1.38	(36)	+0.06	(2)	8.00	(205)	155
5 ¹ / ₈	(130)	5.16	(131.1)	14.75	(375)	±0.06	(±2)	0.12	(3)	9.38	(238)	3.19	(81.1)	7.75	(196.9)	11.50	(292.1)	8	1 ¹ / ₂	(38)	1.62	(42)	+0.06	(2)	10.00	(255)	169
7 ¹ / ₁₆	(179)	7.09	(180.1)	15.50	(395)	±0.12	(±3)	0.25	(6)	10.70	(272)	3.62	(92.0)	9.00	(228.6)	12.50	(317.5)	12	1 ³ / ₈	(35)	1.50	(39)	+0.06	(2)	10.75	(275)	156
9	(228)	9.03	(229.4)	19.00	(485)	±0.12	(±3)	0.25	(6)	13.25	(337)	4.06	(103.2)	11.50	(292.1)	15.50	(393.7)	12	1 ⁵ / ₈	(42)	1.75	(45)	+0.09	(+2.5)	12.00	(305)	157
11	(279)	11.03	(280.2)	23.00	(585)	±0.12	(±3)	0.25	(6)	16.25	(418)	4.69	(119.2)	14.50	(368.3)	19.00	(482.6)	12	1 ⁷ / ₈	(48)	2.00	(51)	+0.09	(+2.5)	13.75	(350)	158
13 ⁵ / ₈	(346)	13.66	(347.0)	26.50	(673)	±0.12	(±3)	0.25	(6)	18.00	(457)	4.44	(112.8)	14.50	(368.3)	23.25	(590.6)	16	1 ⁵ / ₈	(42)	1.75	(45)	+0.09	(+2.5)	12.75	(324)	160

^a Minimum bolt hole tolerance is ± 0.02 in. (0.5 mm).

^a Minimum bolt hole tolerance is ± 0.02 in. (0.5 mm).



^a Optional; optional porting shall have a design rating equal to or higher than the RWP of the flange.

NOTE Raised hub, X_{REF} , raised face, Q , and counterbore, B , are optional. See Table 9 for dimensions B , X , Q , and T and for those not shown.

Figure 6—Type 17SS Integral or Blind Flange

Table 10—Basic Flange and Bolt Dimensions for $\frac{3}{4}$ -in. (19 mm) and 1-in. (25 mm) Type 17SS Flanges

Basic Flange Dimensions													
Pressure-Rating—of Flange		Maximum Bore		Outside Diameter of Flange		Maximum Chamfer		Diameter—of Raised Face		Total Thickness of Flange		Diameter of Hub	
		<i>B</i>		<i>OD</i>		<i>C</i>		<i>K</i>		<i>T</i>		<i>X</i>	
psi	(MPa)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)
Tolerance>		(max)	(max)	±0.06	(±2)	(max)	(max)	±0.02	(±0.5)	±0.02	(±0.5)	±0.02	(±0.5)
17,500	(120.7)	0.75	(19)	6.25	(158.8)	0.12	(3)	2.25	(57.2)	1.62	(41.1)	2.31	(58.7)
15,000	(103.5)	1.02	(26)	6.75	(171.5)	0.12	(3)	3.35	(85.1)	1.62	(41.1)	2.31	(58.7)
Bolting Dimensions													
Pressure-Rating—of Flange		Diameter of Bolt Circle		Number of Bolts	Diameter of Bolts	Diameter of Bolt Holes		Length of Stud Bolts, Flange X Flange		Length of Stud Bolts, Studded X Flange		BX-Ring-Number	
		<i>BC</i>											
psi	(MPa)	in.	(mm)										
Tolerance>		See NOTE 2			-	See NOTE 1		±0.06	(±2)	±0.06	(±2)		
17,500	(120.7)	4.52	(114.8)	4	1.000-8	1.06	(26.9)	5.88	(149)	4.00	(102)	149	
15,000	(103.5)	4.62	(117.3)	4	1.000-8	1.06	(26.9)	5.88	(149)	4.00	(102)	150	

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~~NOTE 1—Tolerance on bolt hole diameter is $+0.06/-0.02$ in. ($+2/-0.5$ mm).~~

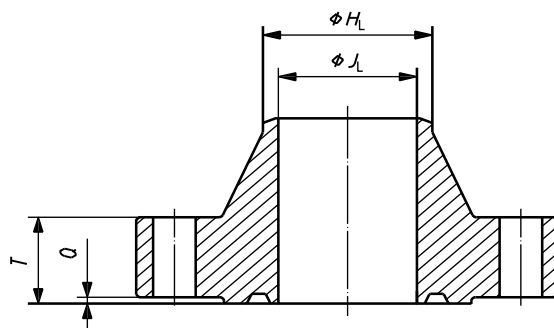
~~NOTE 2—Bolt hole centerline shall be located within 0.03 in. (0.8 mm) of theoretical bolt circle (BC) and equal spacing.~~

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Table 11—Hub and Bore Dimensions for Type 17SS Line Pipe Welding Neck Flanges for 5000 psi (34.5 MPa) Rated Working Pressure



NOTE—See Table 9 for dimensions B , Q , and T and for those not shown.

Nominal Size and Bore of Flange		Neck Diameter of Welding Neck Flange		Tolerance for H_L		Maximum Bore of Welding Neck Flange	
		H_L				$H_L \pm 0.03$ (0.76)	
in.	(mm)	in.	(mm)	in.	(mm)	in.	(mm)
2 ¹ / ₁₆	(52)	2.38	(60.5)	+0.09 -0.03	$\left(\begin{smallmatrix} +2 \\ -0.7 \end{smallmatrix} \right)$	1.69	(43.0)
2 ⁹ / ₁₆	(65)	2.88	(73.2)	+0.09 -0.03	$\left(\begin{smallmatrix} +2 \\ -0.7 \end{smallmatrix} \right)$	2.13	(54.1)
3 ¹ / ₈	(98)	3.50	(88.9)	+0.09 -0.03	$\left(\begin{smallmatrix} +2 \\ -0.7 \end{smallmatrix} \right)$	2.62	(66.5)
4 ¹ / ₁₆	(103)	4.50	(114.3)	+0.09 -0.03	$\left(\begin{smallmatrix} +2 \\ -0.7 \end{smallmatrix} \right)$	3.44	(87.4)
5 ¹ / ₈	(130)	5.56	(141.2)	+0.09 -0.03	$\left(\begin{smallmatrix} +2 \\ -0.7 \end{smallmatrix} \right)$	4.31	(109.5)
7 ¹ / ₁₆	(179)	6.63	(168.4)	+0.16 -0.03	$\left(\begin{smallmatrix} +4 \\ -0.7 \end{smallmatrix} \right)$	5.19	(131.0)
9	(228)	8.63	(219.2)	+0.16 -0.03	$\left(\begin{smallmatrix} +4 \\ -0.7 \end{smallmatrix} \right)$	6.81	(173.0)

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44	(279)	40.75	(273.1)	+0.16 -0.03	$\begin{pmatrix} +4 \\ -0.7 \end{pmatrix}$	8.50	(215.9)
43 ⁵ / ₈	(346)	46.69	(424.0)	+0.16 -0.03	$\begin{pmatrix} +4 \\ -0.7 \end{pmatrix}$	13.61	(347.0)

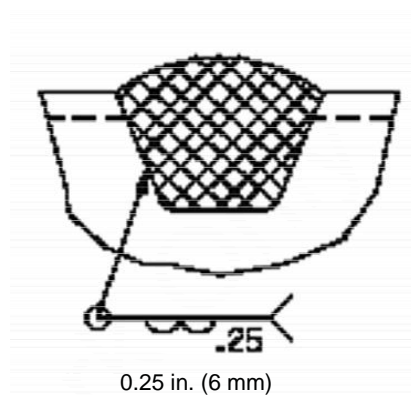
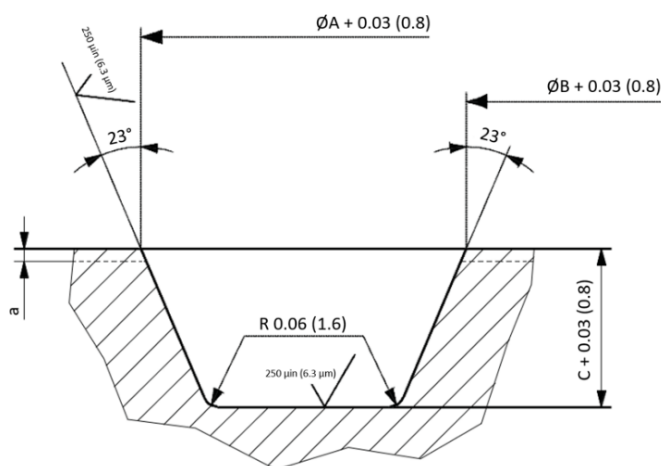
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Table 12—Rough Machining Detail for Corrosion-resistant API Ring Groove

Dimensions in inches (millimeters) unless otherwise noted

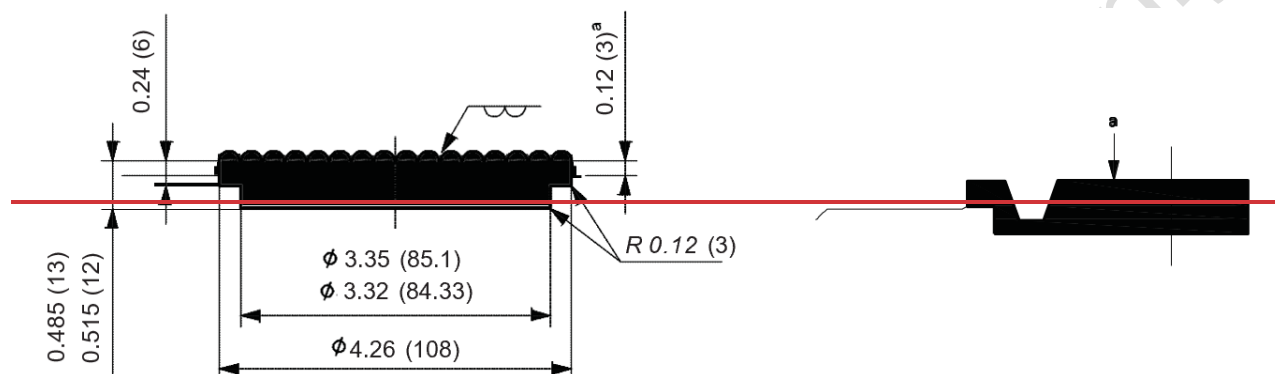


a — 0.13 (3.3) allowed for finish machining.

Ring Number	Outside Diameter of Groove		Inside Diameter of Groove		Depth of Groove	
	in.	(mm)	in.	(mm)	in.	(mm)
BX-149	2.100	(53.34)	1.140	(28.96)	0.350	(8.89)
BX-150	3.326	(84.48)	1.644	(41.76)	0.485	(12.32)
BX-151	3.496	(88.80)	1.774	(45.06)	0.485	(12.32)
BX-152	3.826	(97.18)	2.044	(51.92)	0.505	(12.83)
BX-153	4.486	(113.94)	2.604	(66.14)	0.535	(13.59)
BX-154	5.116	(129.95)	3.114	(79.10)	0.565	(14.35)
BX-155	6.366	(161.70)	4.184	(106.27)	0.595	(15.11)
BX-156	9.956	(252.88)	7.314	(185.78)	0.705	(17.91)
BX-157	12.206	(310.03)	9.324	(236.83)	0.765	(19.43)
BX-159	17.466	(443.64)	14.124	(358.75)	0.895	(22.73)
BX-160	16.496	(419.00)	14.134	(359.00)	0.825	(20.96)
BX-162	19.266	(489.36)	17.064	(433.43)	0.595	(15.11)
BX-163	22.616	(574.45)	19.814	(503.28)	0.985	(25.02)
BX-164	23.186	(588.92)	19.804	(503.02)	0.985	(25.02)
BX-165	25.336	(643.53)	22.394	(568.81)	1.015	(25.78)
BX-166	25.946	(659.03)	22.404	(569.06)	1.015	(25.78)
BX-167	30.686	(779.42)	28.084	(713.33)	1.105	(28.07)
BX-168	30.916	(785.27)	28.094	(713.59)	1.105	(28.07)

BX-158	14.496	(368.20)	11.414	(289.92)	0.825	(20.96)	BX-169	7.396	(187.86)	5.274	(133.96)	0.645	(16.38)
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Dimensions in inches (millimeters)



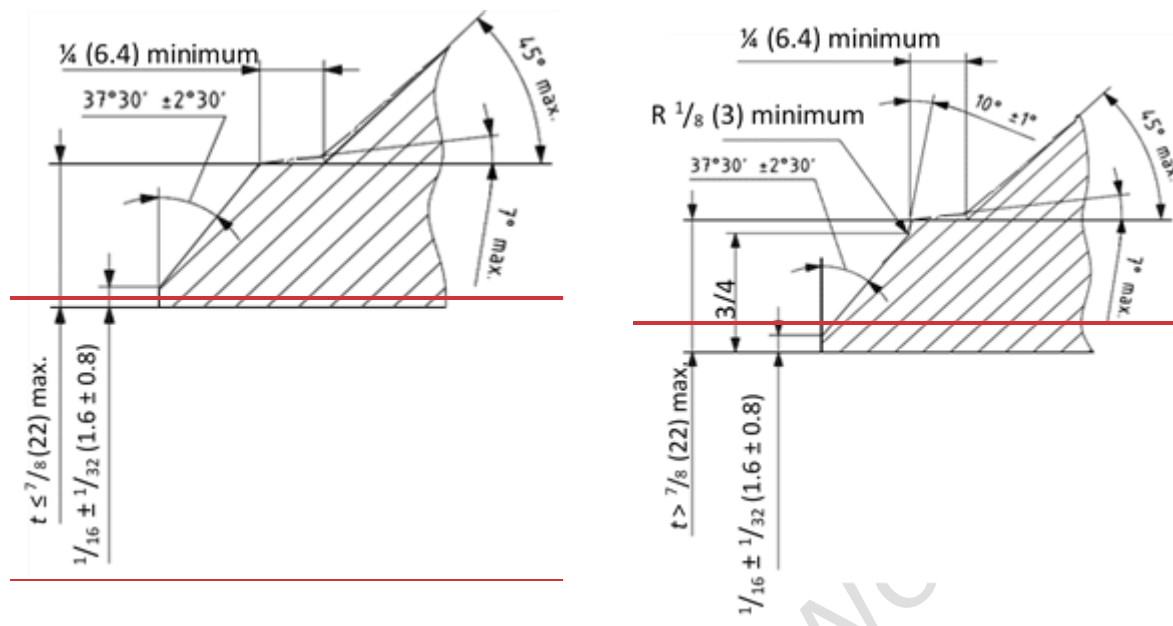
a — Face off for final machine.

NOTE For the BX-149 and BX-150 ring-groove profiles, the flange's raised face profile can come very close to the heat-affected zone (HAZ) created at the outermost diameter of the CRA weld overlay during the finish machining process of the flange, which can cause inspection problems. The alternate rough/finish machine profile illustrated above may be used to avoid HAZ interface problems.

Figure 7—Alternate Rough and Finish Machining Detail for Corrosion-resistant BX-149 and BX-150 Ring Grooves

This alternate weld preparation may be employed only where the strength of the overlay alloy equals or exceeds the strength of the base material and volumetric NDE is performed on the weld metal and fusion zone with the same acceptance criteria as is used for the base metal.

Dimensions in inches (millimeters) unless otherwise indicated



a) For Neck Thickness $\leq \frac{7}{8}$ (22)

b) For Neck Thickness $> \frac{7}{8}$ (22)

Figure 8—Weld End Preparation for Types 17SS and 17SV Welding Neck Flanges

Swivel Flanges—Type 17SV for Working Pressures 5000 psi (34.5 MPa) or 10,000 psi (69 MPa)

General

Type 17SV flanges are multiple-piece assemblies in which the flange rim is free to rotate relative to the flange hub. A retainer groove is provided on the neck of the hub to allow installation of a snap wire of sufficient diameter to hold the ring on the hub during storage, handling, and installation. Type 17SV flanges may be used on subsea completion equipment where it is difficult or impossible to rotate either of the flange hubs to align the mating bolt holes. Type 17SV flanges mate with standard types 6BX and 17SS flanges of the same size and pressure rating.

NOTE Type 17SV swivel flanges are of the ring-joint type and are designed for face-to-face make-up (see Figure 9).

The connection make-up force and external loads shall react primarily on the raised face of the flange.

Dimensions

Dimensions for type 17SV flanges shall conform to Table 13 through Table 16.

Dimensions for welding neck preparations shall conform to Figure 8 and Table 13.

Dimensions for ring grooves shall conform to Table 8 and Table 12.

Flange Face

Flange faces shall be fully machined. The nut bearing surface shall be parallel to the flange gasket face within 1°.

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~~The back face may be fully machined or spot faced at the bolt holes.~~

~~The thickness of type 17SS flanges and type 17SV hubs and swivel rings after facing shall meet the dimensions of Table 9, Table 10, and Table 13 through Table 16, as applicable. The thickness of type 6BX flanges shall meet the requirements of API 6A.~~

Flange Materials

~~The swivel flange materials shall conform to the requirements in 5.2 and 5.3. A minimum yield strength of 75,000 psi (517 MPa) shall be used for type 17SV flanges for 10,000 psi (69 MPa) RWP. The clamp hub portion of a 17SV flange shall conform to 7.2.~~

Marking

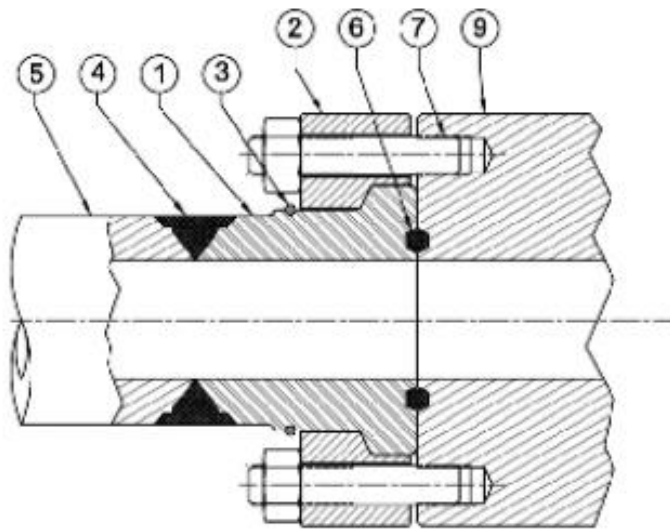
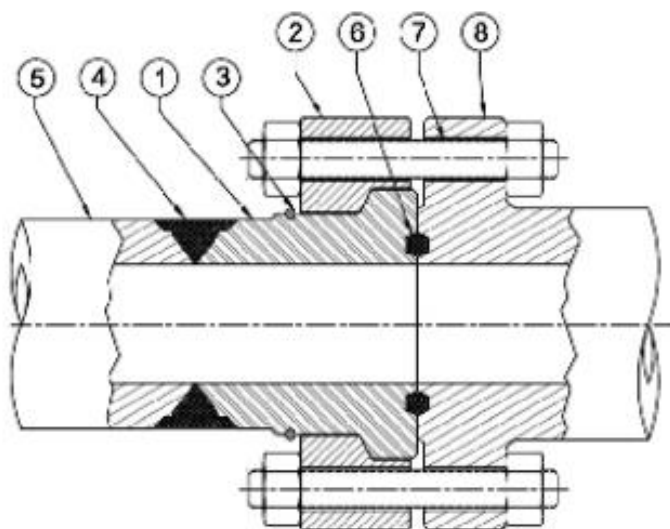
~~Marking of flanged end and outlet connections shall be in accordance with 5.5.1, including the following additional information:~~

~~nominal bore size (if applicable);~~

~~end and outlet connection sizes;~~

~~RWP;~~

~~ring groove type (BX, SBX) and number.~~



Key

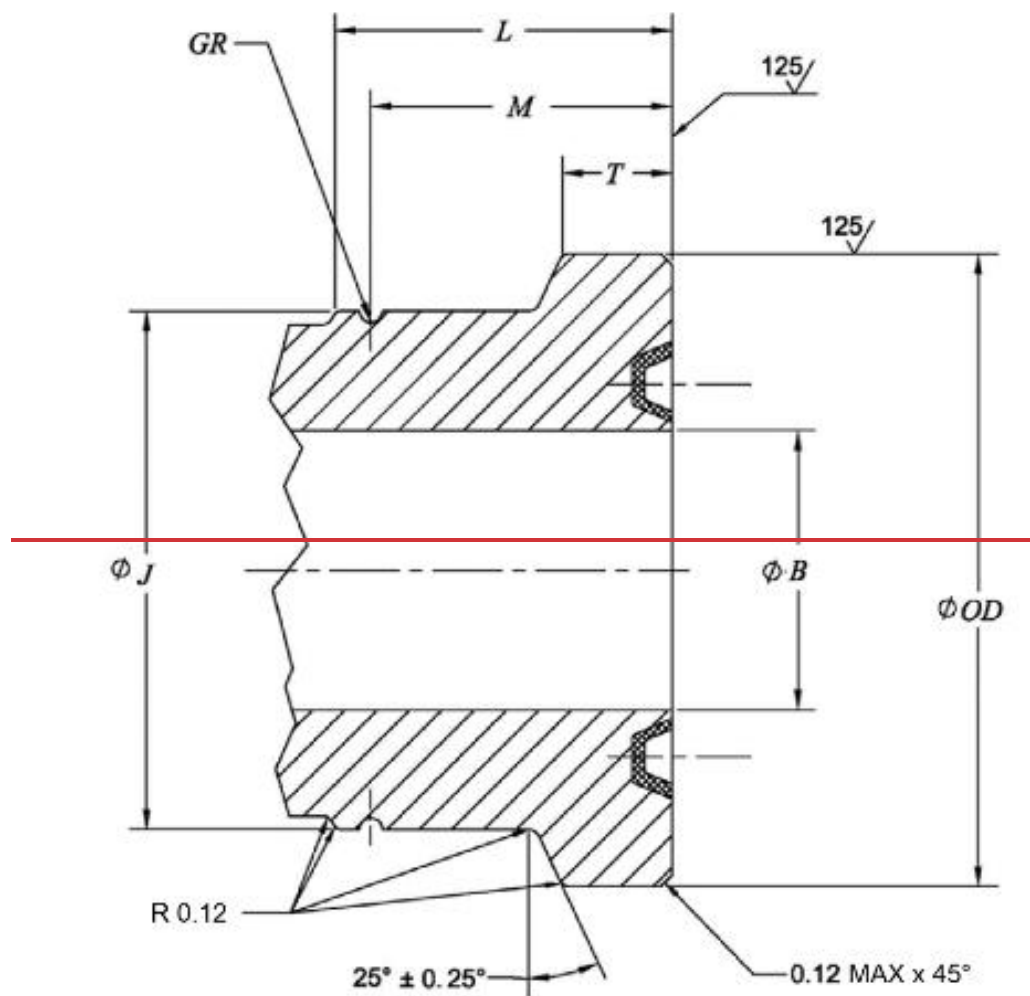
- | | |
|---------------------------------|-------------------------------------|
| 1 — hub (see Tables 13 and 15) | 6 — SBX or BX ring gasket |
| 2 — ring (see Tables 14 and 16) | 7 — closure bolting |
| 3 — retainor ring | 8 — mating API 6BX flange |
| 4 — butt weld (see Figure 8) | 9 — mating API 6BX studed connector |
| 5 — component welded to hub | |

Figure 9—Assembled Type 17SV Flange

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Table 13—Hub Dimensions for Type 17SV Flanges—USC Units



Groove location, M $\frac{+0.030}{0}$

Groove radius, GR $\frac{+0.005}{0}$

Break sharp corners.

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Hub Dimensions for 17SV Flanges for 5000-psi Rated Working Pressure—USC Units

— Dimensions in inches

Nominal- Size (in.)	Maximum Bore	Outside- Diameter	Total- Thickness	Large- Diameter- of Neck	Length- of Neck	Groove- Location	Retainer- Groove- Radius	Ring- Groove
	<i>B</i>	<i>OD</i>	<i>T</i>	<i>J</i>	<i>L</i>	<i>M</i>	<i>GR</i>	
Tolerance:	Maximum	±0.03	+0.03/-0	+0.03/-0	Minimum	+0.030/-0	+0.005/-0	
2 ¹ / ₁₆	2.09	5.03	1.17	3.66	3.28	2.907	0.125	BX-152
2 ⁹ / ₁₆	2.59	5.78	1.17	4.41	3.28	2.907	0.125	BX-153
3 ¹ / ₈	3.09	6.34	1.17	4.94	3.43	3.067	0.125	BX-154
4 ¹ / ₁₆	4.09	7.62	1.20	6.25	3.76	3.382	0.125	BX-155
5 ¹ / ₈	5.16	9.38	1.44	7.75	4.73	4.357	0.125	BX-160
7 ¹ / ₁₆	7.09	10.70	1.62	9.07	5.54	4.979	0.188	BX-156
9	9.03	13.25	1.62	11.62	6.11	5.551	0.188	BX-157
11	11.03	16.25	1.65	14.62	6.93	6.370	0.188	BX-158
13 ⁵ / ₈	13.66	20.62	1.87	19.00	7.15	6.614	0.188	BX-160

Hub Dimensions for 17SV Flanges for 10,000-psi Rated Working Pressure—USC Units

- - - - - Dimensions in inches

Nominal- Size (in.)	Maximum Bore	Outside- Diameter	Total- Thickness	Large- Diameter- of Neck	Length- of Neck	Groove- Location	Retainer- Groove- Radius	Ring- Groove
	<i>B</i>	<i>OD</i>	<i>T</i>	<i>J</i>	<i>L</i>	<i>M</i>	<i>GR</i>	
Tolerance:	Maximum	±0.03	+0.031/-0	+0.03/-0	Minimum	+0.03/-0	+0.005/-0	
1 ¹³ / ₁₆	1.84	4.50	1.166	3.250	3.282	2.907	0.125	BX-151

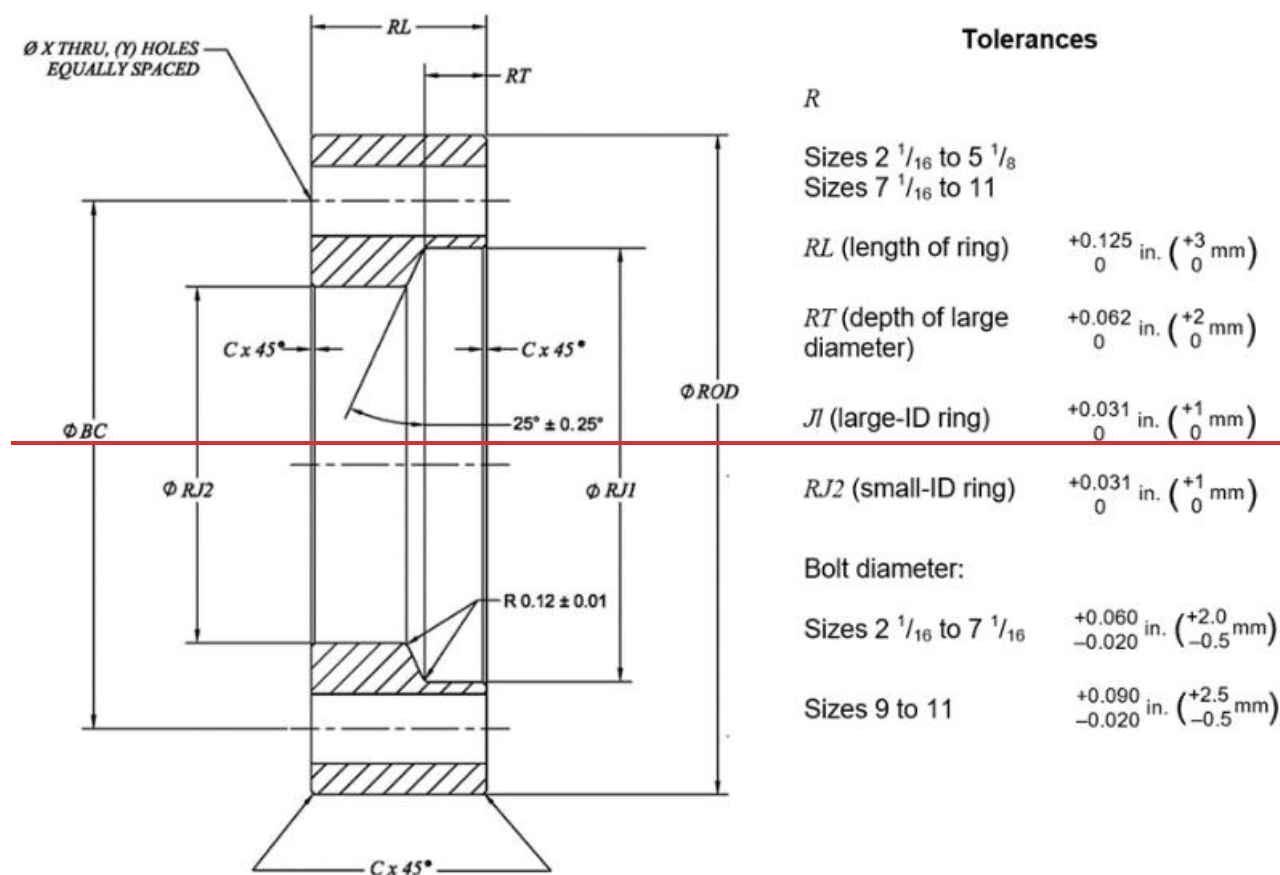
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$2\frac{1}{16}$	2.09	5.00	1.166	3.750	3.282	2.907	0.125	BX-152
$2\frac{9}{16}$	2.59	5.80	1.166	4.550	3.302	2.927	0.125	BX-153
$3\frac{1}{16}$	3.09	6.93	1.197	5.680	3.666	3.291	0.125	BX-154
$4\frac{1}{16}$	4.09	8.44	1.310	6.812	4.277	3.902	0.125	BX-155
$5\frac{1}{8}$	5.16	9.96	1.500	8.335	4.732	4.357	0.125	BX-160
$7\frac{1}{16}$	7.09	13.66	1.653	12.035	6.204	5.641	0.188	BX-156
9	9.03	16.25	1.653	14.625	7.270	6.707	0.188	BX-157
11	11.03	18.87	2.035	17.245	8.153	7.591	0.188	BX-158
$13\frac{5}{8}$	13.66	22.25	2.309	20.625	9.531	8.969	0.188	BX-159

Table 14—Ring Dimensions for Type 17SV Flanges—USC Units

Dimensions in inches



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Ring Dimensions for Type 17SV Flanges for 5000 psi Rated Working Pressure—USC Units

— Dimensions in inches

Nominal Size (in.)	Outside Diameter of Ring	Depth of Large ID	Large ID of Ring	Small ID of Ring	Length of Ring	Chamfer	Bolt Circle	Bolt Hole Qty.	Diameter of Bolt Holes
	<i>ROD</i>	<i>RT</i>	<i>RJ1</i>	<i>RJ2</i>	<i>RL</i>	<i>C</i>	<i>BC</i>	<i>Y</i>	<i>X</i>
Tolerance:	+0.06/-0	+0.06/-0	+0.03/-0	+0.03/-0	+0.12/-0	MAX	See Figure		See Below
2 ¹ / ₁₆	8.50	0.96	5.09	3.72	2.45	0.12	6.50	8	1.00 ⁺⁰⁶ / ₋₀₂
2 ⁹ / ₁₆	9.62	0.96	5.84	4.47	2.45	0.12	7.50	8	1.12 ⁺⁰⁶ / ₋₀₂
3 ¹ / ₈	10.50	0.96	6.38	5.00	2.60	0.12	8.00	8	1.25 ⁺⁰⁶ / ₋₀₂
4 ¹ / ₁₆	12.25	1.00	7.69	6.34	2.93	0.12	9.50	8	1.38 ⁺⁰⁶ / ₋₀₂
5 ¹ / ₈	14.75	1.21	9.44	7.82	3.90	0.12	11.50	8	1.62 ⁺⁰⁶ / ₋₀₂
7 ¹ / ₁₆	15.50	1.42	10.76	9.16	4.46	0.19	12.50	12	1.50 ⁺⁰⁶ / ₋₀₂
9	19.00	1.42	13.34	11.69	5.03	0.19	15.50	12	1.75 ⁺⁰⁹ / ₋₀₂
11	23.00	1.45	16.34	14.69	5.85	0.19	19.00	12	2.00 ⁺⁰⁹ / ₋₀₂
13 ⁵ / ₈	26.50	1.67	20.69	19.06	6.06	0.19	23.25	16	1.75 ⁺⁰⁹ / ₋₀₂

Ring Dimensions for Type 17SV Flanges for 10,000 psi Rated Working Pressure—USC Units

— Dimensions in inches

Nominal Size (in.)	Outside Diameter of Ring	Depth of Large ID	Large ID of Ring	Small ID of Ring	Length of Ring	Chamfer	Bolt Circle	Bolt Hole Qty.	Diameter of Bolt Holes
	<i>ROD</i>	<i>RT</i>	<i>RJ1</i>	<i>RJ2</i>	<i>RL</i>	<i>C</i>	<i>BC</i>	<i>Y</i>	<i>X</i>
Tolerance:	+0.06/-0	+0.06/-0	+0.03/-0	+0.03/-0	+0.12/-0	MAX	See Figure		See Below
1 ¹³ / ₁₆	7.38	0.96	4.562	3.34	2.45	0.12	5.75	8	0.88 ⁺⁰⁶ / ₋₀₂

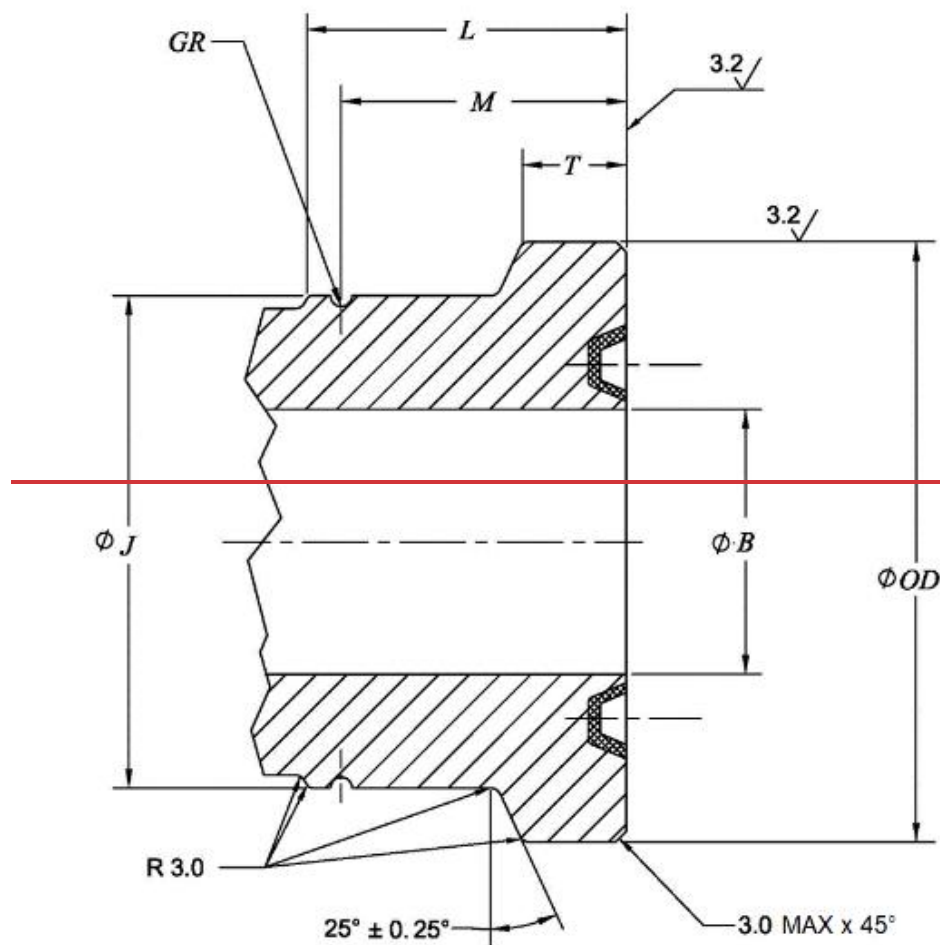
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2 ¹ / ₁₆	7.88	0.96	5.062	3.81	2.45	0.12	6.25	8	0.88 ^{+0.06} / _{-0.02}
2 ⁹ / ₁₆	9.12	0.96	5.862	4.61	2.47	0.12	7.25	8	1.00 ^{+0.06} / _{-0.02}
3 ¹ / ₁₆	10.62	1.00	6.992	5.74	2.83	0.12	8.50	8	1.12 ^{+0.06} / _{-0.02}
4 ¹ / ₁₆	12.44	1.11	8.500	6.88	3.44	0.12	10.19	8	1.25 ^{+0.06} / _{-0.02}
5 ¹ / ₈	14.06	1.30	10.022	8.40	3.90	0.12	11.81	12	1.25 ^{+0.06} / _{-0.02}
7 ¹ / ₁₆	18.88	1.45	13.722	12.10	5.12	0.19	15.88	12	1.62 ^{+0.09} / _{-0.02}
9	21.75	1.45	16.312	14.69	6.19	0.19	18.75	16	1.62 ^{+0.09} / _{-0.02}
11	25.75	1.83	18.932	17.31	7.07	0.19	22.25	16	1.88 ^{+0.09} / _{-0.02}
13 ⁵ / ₈	30.25	2.11	22.312	20.69	8.45	0.19	26.50	20	2.00 ^{+0.09} / _{-0.02}

Table 15—Hub Dimensions for Type 17SV Flanges—SI Units

Dimensions in millimeters



Groove location, $M \begin{pmatrix} +0.7 \\ 0 \end{pmatrix}$

Groove radius, $GR \begin{pmatrix} +0.1 \\ 0 \end{pmatrix}$

Break sharp corners.

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Hub Dimensions for 17SV Flanges for 34.5 MPa Rated Working Pressure—SI Units

— Dimensions in millimeters

Nominal- Size (in.)	Maximum Bore	Outside- Diameter	Total- Thickness	Large- Diameter- of Neck	Length—of Neck	Groove- Location	Retainer- Groove- Radius	Ring- Groove
	<i>B</i>	<i>OD</i>	<i>T</i>	<i>J</i>	<i>L</i>	<i>M</i>	<i>GR</i>	
Tolerance:	Maximum	±0.8	+0.8/-0	+0.8/-0	Minimum	+0.8/-0		-
2 ¹ / ₁₆	53.1	128	29.6	93	84	73.8	3	BX-152
2 ⁹ / ₁₆	65.8	147	29.6	112	84	73.8	3	BX-153
3 ¹ / ₁₆	78.5	160	29.6	126	88	77.9	3	BX-154
4 ¹ / ₁₆	103.9	194	30.5	159	96	85.9	3	BX-155
5 ¹ / ₈	131.1	238	35.8	197	120	110.7	3	BX-169
7 ¹ / ₁₆	180.1	272	41.2	231	141	126.5	5	BX-156
9	229.4	337	41.2	295	156	141.0	5	BX-157
11	280.2	413	42.0	371	176	161.8	5	BX-158
13 ⁵ / ₈	347.0	524	47.5	483	182	168.0	5	BX-160

Hub Dimensions for 17SV Flanges for 69.0 Mpa Rated Working Pressure—SI Units

— Dimensions in millimeters

Nominal- Size (in.)	Maximum Bore	Outside- Diameter	Total- Thickness	Large- Diameter- of Neck	Length—of Neck	Groove- Location	Retainer- Groove- Radius	Ring- Groove
	<i>B</i>	<i>OD</i>	<i>T</i>	<i>J</i>	<i>L</i>	<i>M</i>	<i>GR</i>	
Tolerance:	Maximum	±0.8	+0.8/-0	+0.8/-0	Minimum	+0.8/-0	+0.1/-0	-
4 ¹³ / ₁₆	46.7	114	29.6	82.6	84	74	3	BX-151
2 ¹ / ₁₆	53.1	127	29.6	95.3	84	74	3	BX-152

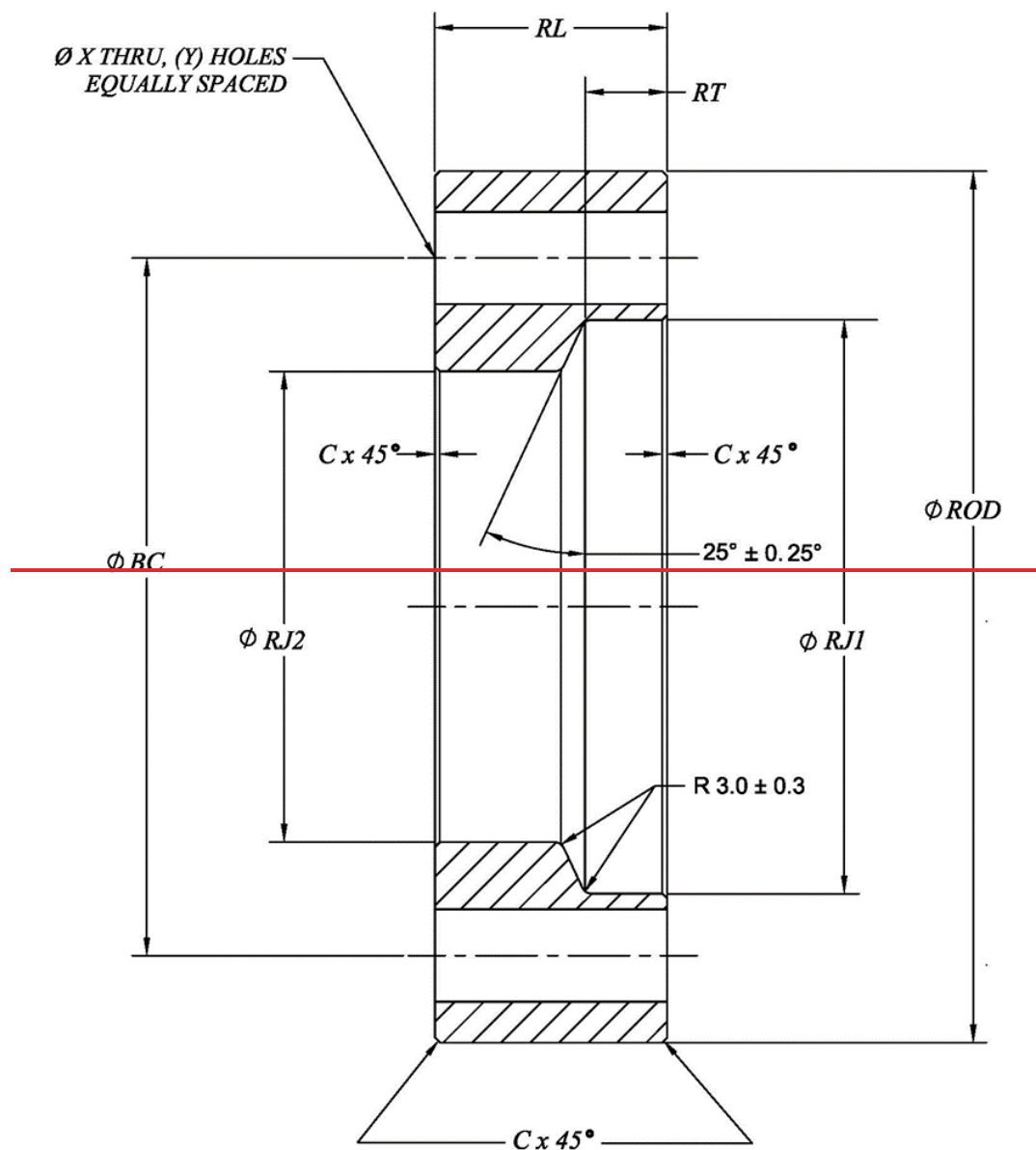
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$2\frac{9}{16}$	65.8	147	29.6	115.6	84	75	3	BX-153
$3\frac{1}{16}$	78.5	176	30.5	144.3	93	84	3	BX-154
$4\frac{1}{16}$	103.9	214	35.8	173.0	109	99	3	BX-155
$5\frac{1}{8}$	131.1	253	41.2	211.7	124	111	3	BX-169
$7\frac{1}{16}$	180.1	347	41.2	305.7	158	143	5	BX-156
9	229.4	413	41.2	371.5	185	170	5	BX-157
11	280.2	479	51.7	438.0	207	193	5	BX-158
$13\frac{5}{8}$	347.0	565	58.6	523.9	242	228	5	BX-159

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~~Dimensions in millimeters~~



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Ring Dimensions for Type 17SV Flanges for 34.5 Mpa Rated Working Pressure—SI Units

— Dimensions in millimeters

Nominal Size (in.)	Outside Diameter of Ring	Depth of Large ID	Large ID of Ring	Small ID of Ring	Length of Ring	Chamfer	Bolt Circle	Number of Bolt Holes	Diameter of Bolt Holes
	<i>ROD</i>	<i>RT</i>	<i>RJ1</i>	<i>RJ2</i>	<i>RL</i>	<i>€</i>	<i>BC</i>	<i>Y</i>	<i>X</i>
Tolerance:	+2/-0	+1.6/-0	+0.8/-0	+0.8/-0	+3/-0	MAX	See Figure		See Below
2 ¹ / ₁₆	216	24.4	129.3	94.5	63	3	165.1	8	26 ⁺² / _{-0.5}
2 ₁₆	246	24.4	148.4	113.5	63	3	190.5	8	29 ⁺² / _{-0.5}
3 ¹ / ₁₆	267	24.4	162.0	127.0	66	3	203.2	8	32 ⁺² / _{-0.5}
4 ¹ / ₁₆	312	25.4	195.3	160.4	75	3	241.3	8	36 ⁺² / _{-0.5}
5 ¹ / ₈	375	30.7	239.8	198.6	99	3	292.1	8	42 ^{+2.5} / _{-0.5}
7 ¹ / ₁₆	394	36.1	273.4	232.1	114	5	317.5	12	39 ⁺² / _{-0.5}
9	483	36.1	338.2	296.9	128	5	393.7	12	45 ^{+2.5} / _{-0.5}
11	585	36.8	414.4	373.1	149	5	482.6	12	51 ^{+2.5} / _{-0.5}
13 ⁵ / ₈	673	42.4	525.4	484.2	154	5	590.6	16	45 ^{+2.5} / _{-0.5}

Ring Dimensions for Type 17SV Flanges for 69.0 Mpa Rated Working Pressure—SI Units

— Dimensions in millimeters

Nominal Size (in.)	Outside Diameter of Ring	Depth of Large ID	Large ID of Ring	Small ID of Ring	Length of Ring	Chamfer	Bolt Circle	Number of Bolt Holes	Diameter of Bolt Holes
	<i>ROD</i>	<i>RT</i>	<i>RJ1</i>	<i>RJ2</i>	<i>RL</i>	<i>€</i>	<i>BC</i>	<i>Y</i>	<i>X</i>
Tolerance :	+2/-0	+1.6/-0	+0.8/-0	+0.8/-0	+3/-0	+0.3/-0	See Figure		See Below
1 ¹³ / ₁₆	187	24.4	115.9	84.1	62	3	146.1	8	23.0 ⁺² / _{-0.5}

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$2\frac{1}{4}$	200	24.4	128.6	96.8	62	3	158.8	8	$23.0^{+2}_{-0.5}$
$2\frac{9}{16}$	232	24.4	148.9	117.1	63	3	184.2	8	$26.0^{+2}_{-0.5}$
$3\frac{1}{4}$	270	25.4	177.6	145.8	72	3	215.9	8	$29.0^{+2}_{-0.5}$
$4\frac{1}{4}$	316	28.2	215.9	174.6	88	3	258.8	8	$32.0^{+2}_{-0.5}$
$5\frac{1}{8}$	357	33.0	254.6	213.3	99	3	300.0	12	$32.0^{+2}_{-0.5}$
$7\frac{1}{4}$	480	36.8	348.5	307.3	130	5	403.4	12	$42^{+2.5}_{-0.5}$
9	552	36.8	414.4	373.0	158	5	476.3	16	$42^{+2.5}_{-0.5}$
11	654	46.6	480.9	439.6	180	5	565.2	16	$48^{+2.5}_{-0.5}$
$13\frac{5}{8}$	768	53.5	566.7	525.4	215	5	673.1	20	$51^{+2.5}_{-0.5}$

~~API Clamp Hub-type Connections~~

~~API clamp-hub-type connections for use on subsea completion equipment shall conform to the dimensional requirements of API 16A. All end and outlet clamp hubs used on subsea completion equipment shall have their ring grooves either manufactured from, or inlaid with, corrosion-resistant materials.~~

~~Corrosion-resistant inlaid ring grooves for clamp hubs shall conform to API 16A. When BX or SBX gaskets are used, corrosion-resistant inlaid ring grooves shall conform to Figure 7 and Table 8. Overlays shall not be required if the base material is compatible with well fluids, seawater, etc.~~

~~Threaded Connections~~

~~Loose threaded flanges and other threaded end and outlet connections shall not be used on subsea completion equipment where the connection is in direct contact with retained fluid with the following exceptions.~~

~~When threaded connections, such as instrument connections, test ports, and injection/monitor connections, are located downstream of the first wing valve, they shall not be greater than 1.00 in. (25.4 mm). They shall conform to the RWP of the tree defined in Table 3 and API 6A.~~

~~When threaded connections are used upstream of the first wing valve, there shall be an isolation valve and either a bolted flange, clamp hub, or welded connection as defined in 7.19.2.6 on the tree side of the threaded connection. The threaded connection shall not be greater than 1.00 in. (25.4 mm). They shall conform to the RWP of the tree defined in Table 3 and API 6A.~~

~~Tubing hangers.~~

~~Sealing areas for threaded connection penetrations shall be made of CRMs.~~

~~Threaded connections used on subsea equipment covered by this specification shall comply with the requirements of 5.1.2.2.~~

~~When threaded fittings are used in chemical injection circuits, mechanical means shall be employed to prevent back-off due to vibration.~~

~~When threaded bleeder/grease/injection fittings are used, these fittings shall be allowed upstream of the first wing valve without the isolation valve and flange/clamp hub if at least two pressure barriers between the produced fluid and the external environment are provided.~~

~~Other End Connectors~~

~~Other nonstandard end connectors, such as misalignment connectors, non-API flanges, ball joints, articulated jumper assemblies, or instrument/monitor flanges may be used in subsea completion equipment when these connectors have been designed, documented, and tested in accordance with the requirements established in Section 5.~~

~~Materials for OECs shall conform to 5.2 and 5.3. Seal surfaces on OECs with metal-to-metal seals used on subsea completion equipment shall be CRA or inlaid with a CRM/CRA that is compatible with well fluids, seawater, etc. If the connector's primary seals are not metal-to-metal, redundant seals shall be provided.~~

~~Marking of other end connections shall be in accordance with 5.5.1, including the following additional information:~~

~~end connection size;~~

~~RWP;~~

~~OEC.~~

~~Studs, Nuts, and Bolting~~

~~Selection of stud, nut, and bolting materials and coatings/platings should address the following:~~

~~seawater-induced chloride stress corrosion cracking;~~

~~corrosion fatigue;~~

~~hydrogen embrittlement induced by cathodic protection systems;—~~

~~effect of coatings on the cathodic protection systems.~~

~~NOTE API 21TR1 provides a reference for materials and coatings/platings for subsea applications.~~

~~Crosses, Tees, and Elbows~~

~~Nominal sizes, pressure ratings, temperature class, flange-studded outlet connection, and ring groove dimensional requirements shall be in accordance with API 6A, as well as Section 5 and 7.1 through 7.5 of this specification.~~

~~NOTE 1 — Only those pressure ratings in API 6A that are also permitted by API 17D may be used (see 5.1.2.1).~~

~~NOTE 2 — The API 6A requirements applicable to crosses and tees also apply to elbows.~~

~~Body dimensions and center-to-face dimensions shall be specified by the manufacturer, with minimum body and flange clearance dimensions conforming to API 6A.~~

~~The pressure rating for a cross, tee, or elbow shall be to the lowest outlet pressure rating of that connector.~~

~~Marking of crosses, tees, and elbows shall be in accordance with 5.5.1, including the following additional information:~~

~~nominal bore size (if applicable);~~

~~end and outlet connection sizes;~~

~~RWP;~~

~~ring groove type (BX, SBX) and number.~~

~~Completion Guidebase~~

~~General~~

~~NOTE The CGB is similar in function to a PGB used on a subsea wellhead. The CGB attaches to either the conductor (low-pressure) housing (after the PGB is removed) or is attached to the tubing head connector (in the same way a tree guide frame is attached to the subsea tree connector). It provides the same guidance for the drilling and subsea completion equipment and provides landing and structural support for ancillary equipment, such as remote OEC flowline connections. The CGB provides guidance of~~

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~~the BOP and subsea tree onto the subsea wellhead or tubing head using guideline or guidelineless methods.~~

~~The CGB shall not interfere with BOP stack installation, ROV access, or cuttings disposal.~~

~~Guidance and orientation with other subsea equipment shall conform to 7.14.2.1.~~

~~Guidance on design and associated load testing shall conform to the requirements in 5.1.3.6.~~

Design

Design Load/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

~~guideline tension;~~

~~flowline pull-in, connection, installation, and operational loads (see 7.17.2.3);~~

~~annulus access connection loads;~~

~~environmental;~~

~~installation loads (including conductor hang-off on spider beams);~~

~~snagging loads;~~

~~BOP and tree loads;~~

~~ROV impact loads.~~

Dimensions

~~The dimensions of the CGB shall conform to the dimensions listed in 7.14.2.1 and 8.3.2.2 and shown in Figure 10 a), unless the orientation system requires tighter tolerances.~~

Tree and Tubing Head Connectors

General

~~Tree and Tubing Head Connectors~~

~~Two validation levels, PR1 or PR2, shall apply for tree and tubing head connectors.~~

~~NOTE—See 7.8.2.2 for load/capacity and 7.8.3.3 for validation requirements.~~

~~All connectors shall be designated by size, pressure rating, and the profile type of the subsea wellhead to which they are attached (see Table 17).~~

Table 17—Wellhead Systems—Standard Sizes and Types

System Designation		High-pressure Working Pressure		Housing Minimum Vertical Bore	
in.; psi	(mm—Mpa)	psi	(Mpa)	in.	(mm)
13 ⁵ / ₈ ; 10,000	(346—69)	10,000	(69.0)	12.31	(313)
13 ⁵ / ₈ ; 15,000	(346—103)	15,000	(103.5)	12.31	(313)
16 ³ / ₄ ; 5000	(425—35)	5000	(34.5)	15.12	(384)
16 ³ / ₄ ; 10,000	(425—69)	10,000	(69.0)	15.12	(384)
18 ³ / ₄ ; 10,000	(476—69)	10,000	(69.0)	17.56	(446)
18 ³ / ₄ ; 15,000	(476—103)	15,000	(103.5)	17.56	(446)
20 ³ / ₄ ; 21 ¹ / ₄ ; 2000	(527—540—14)	2000	(13.8)	18.59	(472)
21 ¹ / ₄ ; 5000	(540—35)	5000	(34.5)	18.59	(472)

Tree/tubing head connectors shall conform to maximum standard pressure ratings of 5000 psi (34.5 Mpa), 10,000 psi (69 Mpa), or 15,000 psi (103.5 Mpa), as applicable. Body proof testing shall be conducted at 1.5 times the RWP. The design and installed preload shall address the potential for higher pressure from an SCSSV seal-sub leakage in the gallery inside the tree connector.

Marking of tree and tubing head connectors shall be per 5.5.1, including performance requirement (PR1, PR2).

Tubing Heads

Applications

NOTE—Tubing heads are commonly used as follows:

provide a crossover between wellheads and subsea trees made by different equipment manufacturers;

provide a crossover between different sizes and/or pressure ratings of subsea wellheads and trees;

provide a surface for landing and sealing a tubing hanger if the wellhead is damaged or is not designed to receive the hanger;

provide a means for attaching any guidance equipment to the subsea wellhead.

Types, Sizes, and Pressure Rating

The tubing head shall be designated by size, pressure rating, and the profile types of its top and bottom connections. Top connections are commonly either hub- or mandrel-type connections that shall match the tree connector. The bottom connection shall match the wellhead.

Tubing heads shall conform to standard RWPs of 5000 psi (34.5 Mpa), 10,000 psi (69 Mpa), or 15,000 psi (103.5 Mpa), as applicable. Body proof testing shall be conducted at 1.5 times the pressure rating. When

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~~the tubing head and connector are manufactured as an integral unit, then the pressure rating shall apply to the entire unit.~~

~~Factory Acceptance Testing~~

~~Tubing head shall be tested per 5.4.5.1 for PSL 2 or PSL 3.~~

~~Tubing head shall be tested per 5.4.6 for PSL 3G.~~

~~Design~~

~~Design Loads/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);~~

~~mechanical preloads;~~

~~riser bending and tension loads (completion and/or drilling riser);~~

~~environmental loads;~~

~~snagging loads;~~

~~fatigue assessment;~~

~~vibration;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler/flowline stab connector thrust and/or preloads;~~

~~thermal expansion (trapped fluids, dissimilar metals);~~

~~BOP loads;~~

~~tree loads;~~

~~flowline loads;~~

~~installation/workover overpull;~~

~~corrosion.~~

~~Load/Capacity~~

~~For PR1 requirements, the manufacturer shall specify the loads/conditions for which tree and tubing head connectors are designed.~~

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~~For PR2 requirements, a capacity chart shall be provided (such as those outlined in API 16A or API 17TR7). The capacity chart shall include rated capacities for normal capacity, extreme capacity, and survival capacity with design factors from API 17TR7 or API 16A.~~

~~Actuating Method~~

~~The manufacturer shall address the following when designing the connector.~~

~~The primary and secondary unlock forces shall be 1.25 times the force required to lock the connector.~~

~~NOTE—The additional unlock force may be provided by additional hydraulic RWP, additional “unlock piston” area, or additional force supplied by another/additional mechanism.~~

~~Connector shall include a secondary release function. Failure of the primary unlock system shall not compromise the secondary unlock function (see 7.8.2.4).~~

~~Document the normal operating pressure (the hydraulic pressure or mechanical force to generate preload) and hydraulic RWP for the connector’s lock function.~~

~~Document the hydraulic RWP (or mechanical force) for the connector’s unlock and secondary release functions.~~

~~Secondary Release~~

~~Hydraulically actuated tree and tubing head connectors shall be designed with a secondary release method, which may be hydraulic or mechanical. Primary hydraulic unlock and lock line piping shall provide a means to be vented, if needed, to allow the secondary release to function.~~

~~NOTE—Isolation valve with hot stab, hot stab, cut away loop (for cutting the lines by diver or ROV) are examples of venting.~~

~~The secondary unlock function shall be designed such that the connector will not unlock upon exposure of the unlock line to ambient pressure.~~

~~Position Indication~~

~~Remotely operated tree connector and/or tubing head connectors shall be equipped with an external position indicator suitable for observation by diver/ROV to confirm connector lock and unlock.~~

~~Self-locking Requirement~~

~~Hydraulic tree and tubing head connectors shall be designed to prevent release due to loss of hydraulic locking pressure.~~

~~Preventing release due to loss of hydraulic locking pressure may be achieved by the connector self-locking mechanism (such as a flat-to-flat locking segment design) or backed up using a mechanical locking device or other demonstrated means.~~

~~The design of mechanical locking devices shall include a means for secondary release in the event of malfunction. The connector and mechanical locking device design shall ensure that locking is effective with worst-case dimensional tolerances of the locking mechanism.~~

~~Overlay of Seal Surfaces~~

~~Seal surfaces for tree and tubing head connectors that engage metal-to-metal seals shall be inlaid with corrosion-resistant material that is compatible with well fluids, seawater, etc. Overlays shall not be required~~

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~~if the base metal is compatible with well fluids, seawater, etc., e.g. if the material is a CRA. Design shall be in accordance with the manufacturer's specifications.~~

Seal Testing

~~Means shall be provided for pressure testing all subsea mated primary seals in the connector to the RWP of the tree/tubing head connector or tubing hanger, whichever is lower.~~

Seal Replacement

~~The design shall allow for the offshore/field replacement of the tree/tubing head connector's subsea mated primary seal, isolation sleeve seals, and/or stab sub seals.~~

Hydraulic Lock

~~The design shall ensure that trapped fluid does not interfere with the installation of the connector.~~

Materials

~~Materials shall conform to 5.2.~~

Testing

General

~~The test procedure in 7.8.3.2 shall apply to both mechanical and hydraulic connectors.~~

Factory Acceptance Testing

~~After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or test fixture. Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Connectors that are hydraulically operated shall have its internal hydraulic circuit, pistons, and cylinder cavities subjected to a hydrostatic test to demonstrate structural integrity. The test pressure shall be a minimum of 1.5 times the hydraulic RWP of the connector. No visible leakage shall be allowed. Minimum hold period for the connector's hydraulic actuator hydrostatic test shall be 3 minutes.~~

Validation

~~PR1 validation of tree and tubing head connectors shall be in accordance with Table 5. PR2 validation of tree and tubing head connectors shall be in accordance with API 17TR7 for PR2 hydraulic connector operational characteristics.~~

Tree Stab/Seal Subs for Vertical Tree

General

~~NOTE Stab subs and seal subs provide pressure controlling conduits between two remotely mated subsea components within the tree/tubing head envelope (valve block to tubing hanger, for example). Stab/seal subs are used on the production (injection) bore, annulus bore, hydraulic couplers, SCSSV control lines, and downhole chemical injection lines.~~

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~~The housing for electrical penetrator(s) shall be treated as a stab sub with respect to the design requirements in 7.9. Stab/seal subs shall be considered pressure-containing if their failure to seal as intended results in a release of wellbore fluid to the environment. Stab/seal subs shall be considered pressure-controlling if at least one additional seal barrier exists between the stab/seal sub and the environment.~~

~~Stab subs and seal subs in the production and annulus bore should conform to standard maximum pressure ratings of 5000 psi (34.5 Mpa), 10,000 psi (69 Mpa), or 15,000 psi (103.5 Mpa) as covered by this specification. The effects of pressure acting externally on stabs and seal subs shall be addressed up to the tree pressure rating, pressure rating of any seal sub in the annulus envelope outside the seal stab, or the hyperbaric pressure rating, whichever is greatest. Stab subs or seal subs used to conduct SCSSV control fluid, other hydraulic fluids, or injected chemicals shall be rated to a working pressure equal to or greater than the SCSSV control pressure or injection pressure, respectively, whichever is the higher, and be limited to 2500 psi (17.2 Mpa) plus the RWP of the tree.~~

~~Proof testing shall be at 1.0 times the stab/seal sub pressure rating if the stab/seal sub is pressure-controlling, and 1.5 times the stab/seal sub pressure rating if the stab/seal sub is pressure-containing. Working pressure tests shall be at the pressure rating of the seal sub and its fluid passage. Galleries outboard of the stab/seal sub shall be tested to the highest pressure rated stab/seal sub in that gallery, unless a means to vent the gallery is provided, in which case the gallery test shall be at the RWP rating of the interface.~~

Design

Design Loads/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

~~NOTE The following may apply:~~

~~internal and external pressure;~~

~~separation loads;~~

~~bending loads during installation;~~

~~thermal expansion;~~

~~corrosion;~~

~~galling.~~

Seal Design

~~The seal mechanism may be either a metal-to-metal or a redundant nonmetallic seal.~~

~~CRM shall be used for the metal-to-metal seal sub designs and is recommended for redundant nonmetallic seal designs.~~

Valves, Valve Blocks, and Actuators/Operators

Overview

Flanged End Valves

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~~Valves having API type flanged end connections shall use integral, studded, or welding neck flanges as specified in 7.1.~~

~~For units having end and outlet connections with different pressure ratings, the rating of the lowest-rated pressure-containing part shall be the rating of the unit.~~

~~Other End Connector Valves~~

~~Clamp-type connections shall conform to API 16A. OECs shall conform to 7.4.~~

~~Design~~

~~Valves and Valve Blocks~~

~~General~~

~~Valves and valve blocks used in the subsea tree bores and tree piping shall conform to the applicable bore dimensional requirements of API 6A. Other valve and valve block dimensions shall conform to 7.1 through 7.6.~~

~~If the lower end connection of the tree that mates to the tree connector encapsulates SCSSV control lines that have a higher pressure rating than the tree pressure rating, the design shall address leaking control lines or seal subs unless relief is provided as specified in 5.1.2.1. Proof testing of the end connections and body shall be at 1.5 times RWP of the valve block.~~

~~Consideration should be given to the inclusion of diver/ROV valve overrides, particularly in the vertical run, to facilitate well intervention in the event of hydraulic control failure.~~

~~Penetrations shall not be permitted for the purpose of greasing, back seat testing, or for testing secondary stem seals.~~

~~Where pressure may become trapped between seals, the function of the valve shall not be adversely affected.~~

~~Valves~~

~~The following shall apply to all valve types.~~

~~Valves shall have their service classification in conformance with Section 5, with respect to pressure rating, temperature, and material class. Additionally, USVs shall, as a minimum, be rated for class II sandy service as defined by API 6AV1.~~

~~Valves designated as USVs shall meet the requirements in 7.10.6.~~

~~Valves for subsea service shall address the impact of external pressure and the environment as well as internal fluid conditions.~~

~~Manufacturers of subsea valves shall document design and operating parameters of the valves as listed in Table 18.~~

~~Measures shall be taken to ensure that there are no burrs or upsets at the gate and seat bores that can damage the gate and seat surfaces or interfere with the passage of wireline tools.~~

~~Valve Blocks~~

~~Valve blocks shall meet the design requirements given in 6.1 and in API 6A.~~

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~~Dual-bore valve blocks shall meet the applicable design requirements of API 6A. Table 19 specifies the center distances for dual parallel bore valve blocks designed to this specification. There are no specific end-to-end dimension or outlet requirements for these valve blocks.~~

~~Other multiple-bore valve block configurations shall meet the applicable design requirements of API 6A.~~

Table 18—Operating Parameters of Valves and Actuators/Operators

A	Valve
1	Nominal bore size
2	RWP
3	Class of service
4	Temperature classifications
5	Type and size connections ^a
6	Valve stroke
7	Overall external dimensions and mass ^a
8	Materials class rating
9	Reset position (open, closed, in-place)
10	Unidirectional or bidirectional (flow through valve bore—for unidirectional, mark external of valve body with flow direction arrow)
11	Position indicator type (visual, electrical, etc.)
B	Actuator (Hydraulic, Electric, or Hybrid)
1	Minimum hydraulic operating pressure or electric power
2	Maximum allowed hydraulic operating pressure or electric power (volts, amps), at continuous stall
3	Temperature classifications
4	(Hydraulic) actuator volume displacement ^a
5	Number of turns to open/close valve ^b
6	Override force or torque required ^b
7	Maximum override force or torque ^b
8	Maximum override speed ^b
9	Overall external dimensions and mass
10	Override type and class (in accordance with API 17H) ^b
11	Make and model number of valves the actuator is designed for
C	Valve/Actuator Assembly
1	Maximum water depth rating
At maximum rated depth of assembly and maximum rated bore pressure, the actuator hydraulic pressure in psi (Mpa) or electric power in Watts at the following valve positions:	
2	Start to open from previously closed position
3	Fully open
4	Start to close from previously open position
5	Fully closed
At maximum rated depth of assembly and 0 psi (Mpa), bore pressure, the actuator hydraulic pressure, expressed in psi (Mpa) or electric power in Watts in at the following valve positions:	
6	Start to open from previously closed position
7	Fully open

8	Start to close from previously open position
9	Fully closed
Where applicable,	
All dimensions shall comply with ISO 15926-4	

Table 19—Center Distances of Conduit Bores for Dual Parallel Bore Valve Blocks

Valve Size in. (mm)	Valve-bore Center to Valve-bore Center in. (mm)	Large Valve-bore Center to Block-body Center in. (mm)
5000 psi (34.5 Mpa)		
2¹/₁₆ × 2¹/₁₆ (52 × 52)	3.547 (90.09)	1.774 (45.06)
2⁹/₁₆ × 2¹/₁₆ (65 × 52)	3.547 (90.09)	1.650 (41.91)
3¹/₈ × 2¹/₁₆ (79 × 52)	4.578 (116.28)	2.008 (51.00)
4¹/₁₆ × 2¹/₁₆ (103 × 52)	4.563 (115.90)	1.750 (44.45)
5¹/₈ × 2¹/₁₆ (130 × 52)	4.500 (114.30)	0.0
10,000 psi (69.0 Mpa)		
2¹/₁₆ × 2¹/₁₆ (52 × 52)	3.550 (90.17)	1.774 (45.05)
2⁹/₁₆ × 2¹/₁₆ (65 × 52)	4.000 (101.60)	1.875 (47.63)
3¹/₁₆ × 2¹/₁₆ (78 × 52)	5.050 (128.27)	2.524 (64.10)
4¹/₁₆ × 2¹/₁₆ (103 × 52)	5.000 (127.00)	1.625 (41.28)
5¹/₈ × 2¹/₁₆ (130 × 52)	5.750 (146.05)	0.0
15,000 psi (103.5 Mpa)		
2¹/₁₆ × 2¹/₁₆ (52 × 52)	3.550 (90.17)	1.774 (45.05)
2⁹/₁₆ × 2¹/₁₆ (65 × 52)	4.000 (101.60)	1.875 (47.63)
3¹/₁₆ × 2¹/₁₆ (78 × 52)	5.050 (128.27)	2.524 (64.10)
4¹/₁₆ × 2¹/₁₆ (103 × 52)	5.500 (139.70)	1.125 (28.58)
5¹/₈ × 2¹/₁₆ (130 × 52)	6.750 (171.45)	0.0

~~Bore-position seal-preparation centers shall be within 0.005 in. (0.13 mm) of their true position with respect to the block-body center or block-body end connection seal. Bores shall be true within 0.010 in. (0.25 mm) total indicator reading with respect to the centers of the bore seal preparation.~~

~~Actuators/Operators~~

~~General~~

~~The following apply to the design of subsea valve actuators/operators.~~

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~~Actuators/operators should be designed to prevent functional impairment by marine growth, fouling, calcareous deposit, hydrate formation at seawater boundaries, or corrosion/deterioration caused by the environment, hydraulic operating or compensation fluids, and, if exposed, the well stream fluid.~~

~~Designs shall be capable of operating a valve or group of valves. An actuator/operator paired to work together with a valve shall meet or exceed the functional performance requirements set for operating the valve, including the requirements in this section.~~

~~Designs shall be capable of operating the valve without damage to the valve or actuator/operator (to such an extent that prevents meeting any other performance requirement), when the actuation force (within its rated working force/torque, hydraulic operating pressure, or electric power rating) is either applied or removed under any valve bore pressure conditions or stoppage of the valve bore sealing mechanism at any intermediate position.~~

~~Designs shall account for the effect of external hydrostatic pressure at the manufacturer's maximum rated water depth and the RWP of the valve.~~

~~Manual overrides, if provided, shall be in accordance with the following requirements for fail-closed valves.~~

~~A rotation type override shall open the valve with a counter-clockwise rotation looking at the end of the stem.~~

~~A linear type override for fail-closed valve shall open the valve with a push on the override.~~

~~For fail-open, fail-in-place, or position indexed (stepping) actuated valves, the manufacturers shall document the method for override.~~

~~The manufacturer shall document the method, procedures and operating limits for override.~~

~~If a design feature to separate an actuator from a valve is provided, the design should demonstrate that the valve stem does not move during actuator removal/replacement to satisfy the actuator removal requirement. Before removal of the actuator, the hydraulic or electric power conduits leading to the actuator should be isolated and/or sealed off prior to removal/connection of the actuator and done under a vented or powered down state.~~

~~Position indicators, if provided, shall show a valve's position from full-open to full-closed. Where the actuator incorporates a manual override, the position indicator shall be visible from the diver/ROV's working position with override tool installed.~~

~~Water depth rating—Manufacturer shall specify the maximum water depth rating of the actuator/operator assembly. Water depth rating shall be based on the design's external pressure as a function of water depth using seawater specific gravity of 1.03. If pressure compensation is required, the design of the actuator/operator should pressure compensate all fluid filled chambers accounting for the maximum rated water depth and the thermal expansion coefficient of the fluids.~~

~~Other subsea actuator/operator performance criteria can be specified, such as wire/coiled tubing shearing design criteria, but these shall be addressed separately from the above fundamental set of criteria.~~

~~Hybrid actuator designs, such as electro-hydraulic actuators, shall meet the appropriate requirements of these sections for their respective subassemblies and components within.~~

~~Manual Operator~~

~~The following requirements apply to manual operator.~~

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~~The design of the manual operator mechanism shall address the ability of divers and/or ROVs, for operations. Manual valves shall be operable by divers and/or ROVs.~~

~~Manufacturers of manual operators or overrides for subsea valves shall document maintenance requirements, number of turns to open, operating torque, maximum allowable torque, or appropriate linear force to actuate.~~

~~Valves shall be turned in the counter-clockwise direction to open and the clockwise direction to close as viewed from the end of the stem for fail-closed valves.~~

~~Intervention fixtures for manual operators shall conform to the requirements of API 17H.~~

Hydraulic Actuators

The following requirements apply to hydraulic actuators.

Actuator manufacturer shall document design and operating parameters, as listed in Table 18.

Actuator opening and closing force shall be sufficient to operate the subsea valve when the valve is at the most severe design operating conditions without exceeding 90 % of the hydraulic system RWP (hydraulic RWP). This requirement is intended to ensure that the actuator is adequately designed to operate with the hydraulic source at FAT and SIT without the pressure (ambient external and hydraulic pressure head) associated with water depth.

The actuator shall be designed to control the subsea valve when the valve is at its most severe design condition and at the hydraulic pressure(s) associated with the most severe intended operating sequence of the valve(s) that are connected to a common supply. This implies that the actuator shall be able to ensure that fail-closed (or fail-open or fail-in-place) valves retain their fail (reset) position, and can subsequently respond to a command to move the valve to its actuated position, over the range of hydraulic supply pressure created by a severe operating sequence, due to extremely long offsets, supply drawdown, or multiple valve/function operations, etc.

An actuator fail-safe spring return mechanism shall be designed and verified to provide a spring with a minimum life of 5000 actuation cycles.

Hydraulic actuators shall have porting to facilitate flushing of the hydraulic cylinder in order to meet hydraulic fluid cleanliness requirements.

Closing/opening force—The subsea valve and hydraulic actuator assembly design shall use valve bore pressure and/or spring force to assist closing of the fail-close position valve (or opening for a fail-open position valve).

Actuator protection from wellbore pressure—Means shall be provided to prevent overpressuring of the actuator piston and compensation chambers, in the event that wellbore pressure leaks into the actuator.

Water depth rating—Manufacturer shall specify the maximum water depth rating of the valve/actuator assembly. Subsea valve and actuator assemblies designated as fail-closed (open) shall be designed and fabricated to be capable of fully closing (opening) the valve at the maximum rated water depth under all of the following conditions:

from 14.7 psia (0.10 Mpa absolute) to maximum working pressure of the valve in the valve bore;

differential pressure equal to the rated bore pressure across the valve bore sealing mechanism at the time of operation;

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~~external pressure on the valve/actuator assembly at the maximum rated water depth using seawater specific gravity of 1.03;~~

~~no hydraulic assistance in the closing (opening) direction of the actuator other than hydrostatic pressure at the operating depth;~~

~~for hydraulic actuators, 100 psi (0.69 Mpa) plus seawater ambient hydrostatic pressure at the maximum rated depth of the assembly acting on the actuator piston in the opening (closing) direction.~~

~~NOTE—The maximum water depth rating is calculated using the above set of “extreme worst case” conditions for the purpose of standard reference but does not necessarily represent operating limitation. Additional information relating to operating water depth for specific applications can be provided and agreed between manufacturer and user/purchaser as being more representative of likely field conditions.~~

Electric Actuators

~~The following requirements apply to electric actuators.~~

~~Actuator manufacturer shall document design and operating parameters, as listed in Table 18.~~

~~Actuator shall be designed to require no more than 90 % of its rated torque/force capability to operate the valve in the most severe design operating condition.~~

~~The actuator shall be designed to control the subsea valve when the valve is at its most severe design condition and have sufficient stored energy for the most severe intended operating sequence of the valve(s).~~

~~Actuator with a permanently installed energy storage device for fail-close or fail-open functions shall be designed to provide an energy storage device with a minimum life of 5000 full actuation cycles (open to close and close to open—reference J.4.1).~~

~~Retrievable energy storage devices should have a minimum capacity of 100 % of the storage device manufacturer's rated design lifetime.~~

~~NOTE—Storage device lifetime is defined as the time until the energy storage device provides minimum energy requirement to operate the valve/device.~~

~~Use of electric actuator on a manual operator valve shall be acceptable only if the valve/manual operator has been qualified to 600 endurance cycles.~~

~~Actuator protection from wellbore pressure and temperature—Means shall be provided to prevent over-pressuring of the actuator electrical housing and compensation chambers, if wellbore pressure leaks into the actuator. Thermal protection for the motor and electrical components shall be provided.~~

~~Electrical subassemblies and components such as winding stators/rotors energy storage units and controllers shall be in accordance with the requirements of API 17F or the applicable standards (such as IEC/CENELEC). Electrical control latching (hold-open) power shall be in accordance with manufacturer's written specification. This should include end of valve or choke service life.~~

~~Closing/opening force—The subsea valve and electric actuator assembly design shall use valve bore pressure and/or a stored energy source (such as a spring, permanent magnet, or battery) to assist closing of the fail-close position valve (or opening for a fail-open position valve).~~

Materials

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~~Materials for valves, valve blocks, and actuators shall conform to 5.2. Seal surfaces that engage metal-to-metal seals shall be inlaid with a CRM that is compatible with well fluids, seawater, etc.~~

~~NOTE—Overlays are not required if the base material is compatible with well fluids, seawater, etc.~~

Testing

Validation

General

~~Testing shall validate specific valve and valve actuator/operator designs manufactured under this specification (see 5.1.7).~~

~~NOTE—Annex J provides information on a consistent method of conducting validation on valves and actuators conforming to this specification, by prescribing the types of cycles and the order in which the cycles are to be performed.~~

Valve and Hydraulic Actuator Assembly Testing

~~Subsea valve and actuator assemblies shall be tested to demonstrate the performance limits of the assembly. Unidirectional valves shall be tested with pressure applied in the intended direction. Bidirectional valves shall be tested with pressure applied in both directions in separate tests.~~

~~For a fail-closed (fail-open) valve, with the assembly subjected to external pressure (actual or simulated) of the maximum rated water depth and full rated bore pressure, applied as a differential across the gate, the valve shall open (close) fully from a previously closed (open) position with a maximum of 90 % of the hydraulic system RWP above actual or simulated external pressure.~~

~~For a hydraulic fail-closed (fail-open) valve, with the assembly subjected to the external pressure (actual or simulated) of the maximum rated water depth and atmospheric pressure in the body cavity, the valve shall be shown to move from a previously fully open (closed) position to a fully closed (open) position as the hydraulic pressure in the actuator is lowered to a minimum of 100 psi (0.69 Mpa) above external pressure.~~

~~Validation of a fail-closed (or fail-open) valve/actuator assembly may be used to validate an equivalent fail-open (fail-close) valve/actuator design, provided that the fail-open (fail-closed) valve/actuator is subjected to a functional stroking tested with external pressure applied, one cycle with the valve bore at RWP, and the second with the bore at atmospheric pressure.~~

~~For a fail-in-place valve, with the assembly subjected to the external pressure (actual or simulated) of the maximum rated water depth, the valve shall close or open fully from a previously open or closed position with a maximum of 90 % of the operating hydraulic system RWP above actual or simulated external pressure. A fail-in-place hydraulically actuated valve shall remain in position as the hydraulic control pressure in the actuator is lowered to a minimum of 100 psi (0.69 MPa) above external pressure.~~

Valve and Electric Actuator Assembly Testing

~~This section covers the performance requirements for a fully assembled, valve/actuator set.~~

~~For a fail-closed (fail-open) valve, with the assembly subjected to external hydrostatic pressure (actual or simulated) of the maximum rated water depth and full rated bore pressure, applied as a differential across the gate, it shall be shown that the valve opens (closes) fully from a previously closed (open) position with a maximum of 90 % of the minimum electric power, applied to the actuator, PMR.~~

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~~For a fail-closed (fail-open) valve, with the assembly subjected to the external hydrostatic pressure (actual or simulated) of the maximum rated water depth and atmospheric pressure in the body cavity, the valve shall be shown to move from a previously fully open (closed) position to a fully closed (open) position in the event of loss of power and loss of communication.~~

~~For a fail-in-place valve, with the assembly subjected to the external hydrostatic pressure (actual or simulated) of the maximum rated water depth, the valve shall be shown to closed or open fully from a previously open or closed position with a maximum of 90 % of the minimum electric power, applied to the actuator, PMR. A fail-in-place electric valve shall remain in position in the event of loss of power and loss of communication.~~

Factory Acceptance Testing

General

~~Each subsea valve and valve actuator/operator shall be subjected to a hydrostatic and operational test to demonstrate the structural integrity and proper assembly and operation of each completed valve and/or actuator/operator.~~

~~NOTE—Table 20 and Table 21 offer examples of test documentation.~~

Table 20a—Example of PSL 2 Valve Factory Acceptance Test Documentation

Valve Body Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Primary body test (TP) 3-minute hold				NA	NA	NA
Secondary body test (TP) 3-minute hold				NA	NA	NA
Valve Seat Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Seat test (RWP) 3-minute hold				NA	NA	NA
First hydrostatic break open seat		NA	NA	NA	NA	NA
Seat test (RWP) 3-minute hold (PSL 2)				NA	NA	NA
Second hydrostatic break open seat		NA	NA	NA	NA	NA
Seat test (RWP) 3-minute hold (PSL 2)				NA	NA	NA
^a Opposite seat test (RWP) 3-minute hold				NA	NA	NA
^a First hydrostatic break open opposite seat		NA	NA	NA	NA	NA

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^a Opposite seat test (RWP) 3-minute hold				NA	NA	NA
^a Second hydrostatic break open opposite seat		NA	NA	NA	NA	NA
^a Opposite seat test (RWP) 3-minute hold				NA	NA	NA
Drift test	Successfully completed Yes/No (as applicable)					
^a Bidirectional sealing valves only.						

Table 20b—Example of PSL 3 Valve Factory Acceptance Test Documentation

Valve Body Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Primary body test (TP) 3-minute hold				NA	NA	NA
Second body test (TP) 15-minute hold (PSI 3)				NA	NA	NA
Valve Seat Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Seat test (RWP) 3-minute hold				NA	NA	NA
First hydrostatic break open seat		NA	NA	NA	NA	NA
Seat test (RWP) 15-minute hold (PSI 3)				NA	NA	NA
Second hydrostatic break open seat		NA	NA	NA	NA	NA
Seat test (RWP) 15-minute hold				NA	NA	NA
a—Opposite seat test (RWP) 3-minute hold				NA	NA	NA
a—First hydrostatic break open opposite seat		NA	NA	NA	NA	NA
a—Opposite seat test (RWP) 15-minute hold				NA	NA	NA
a—Second hydrostatic break open opposite seat		NA	NA	NA	NA	NA
a—Opposite seat test (RWP) 15-minute hold				NA	NA	NA
Drift test	Successfully completed Yes/No (as applicable)					
a———— Bidirectional sealing valves only.						

Table 20c—Example of PSL 3G Valve Factory Acceptance Test Documentation

Valve Body Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Primary body test (TP) 3-minute hold				NA	NA	NA
Second body test (TP) 15-minute hold (PSL 3G)				NA	NA	NA
Third body test (RWP) 15-minute hold (PSL 3G)	NA	NA	NA			
Valve Seat Pressure Test						
	Hydrostatic Test			Gas Test		
	PSI	Start Time	End Time	PSI	Start Time	End Time
Seat test (RWP) 3-minute hold				NA	NA	NA
First hydrostatic break open seat (RWP)		NA	NA	NA	NA	NA
Seat test (RWP) 15-minute hold				NA	NA	NA

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Second hydrostatic break open seat (RWP)		NA	NA	NA	NA	NA
a Opposite seat test (RWP) 2 minute hold				NA	NA	NA
a First hydrostatic break open opposite seat (RWP)		NA	NA	NA	NA	NA
a Opposite seat test (RWP) 15 minute hold				NA	NA	NA
a Second hydrostatic break open opposite (RWP)		NA	NA	NA	NA	NA
Seat gas test (RWP) 15-minute hold	NA	NA	NA			
Seat gas test (L P) 15-minute hold	NA	NA	NA			
a Opposite seat gas test (RWP) 15-minute hold	NA	NA	NA			
a Opposite seat gas test (L P) 15-minute hold	NA	NA	NA			
Drift test	Successfully completed Yes/No (as applicable)					
a Bidirectional sealing valves only.						

Table 21—Example Documentation of the Factory Acceptance Testing for a Hydraulic Actuator

Factory Acceptance Test Form for Hydraulic Actuator				
Test Sequence (3-minute minimum hold period)		Hydrostatic Test		
		Pressure	Start Time	End Time
1	Control port hydrostatic test (1.5 times hydraulic RWP)			
2	Control port hydrostatic test (1.5 times hydraulic RWP)			
3	Control port seal test (0.2 times hydraulic RWP)			
4	Control port seal test (1.0 times hydraulic RWP)			
5	Compensation port hydrostatic test (1.5 times compensation working pressure)			
6	Spring chamber hydrostatic test (1.5 times compensation working pressure)			
7	Actuator function test: Complete three cycles			
8	Manual operation test: Complete three cycles (rotary design) one cycle (linear design)	Stroke, expressed as inches (millimeters) per number of turns to operate	Force per torque, expressed as pounds (newtons) per foot (newton-meters) with differential pressure	Force per torque, expressed as pounds (newtons) per foot (newton-meters) with differential pressure

~~Subsea Valve~~

~~Each subsea valve shall be factory acceptance tested in accordance with PSL 2 or PSL 3 or PSL 3G, as specified in 5.4.5 or 5.4.6.~~

~~Subsea Valve Actuator~~

~~Hydraulic Actuator Hydrostatic Body Test~~

~~Each hydraulic actuator cylinder and piston shall be subjected to a hydrostatic body test to demonstrate structural integrity. The test pressure shall be a minimum of 1.5 times the hydraulic RWP of the actuator. No visible leakage shall be allowed.~~

~~There shall be a minimum of two hold periods at no less than 3 minutes each.~~

~~Actuator Operational Test~~

~~The actuator shall be tested for proper operation by stroking the actuator from the fully closed position to the fully open position, a minimum of three times, per the manufacturer's written specification. The actuator should operate smoothly (no evidence of stick-slip movement, sometimes referred to as chatter) in both directions in accordance with the manufacturer's written specification. Test media for hydraulic actuators shall be specified by the manufacturer.~~

~~NOTE—Cycling prior to further testing followed by low-pressure testing in the next step confirms that the seals were not damaged by the high-pressure test.~~

~~Hydraulic Actuator Seal Test~~

~~The actuator seals shall be pressure tested in two steps by applying pressures of 0.2 times the hydraulic RWP and a minimum of 1.0 times the hydraulic RWP of the actuator. No seal leakage shall be allowed. The test media shall be specified by the manufacturer. The minimum test duration for each test pressure shall be 3 minutes. The test period shall not begin until the test pressure has been reached and has stabilized. The test gauge pressure reading and time at the beginning and at the end of each pressure holding period shall be recorded.~~

~~The low-pressure test shall not apply to hydraulic piston flowby-type actuators.~~

~~Hydraulic Actuator Compensation Circuit Test~~

~~The actuator compensation chamber and circuit shall be tested per the manufacturer's written specification.~~

~~NOTE—Compensating barriers are found in 6.2.13.~~

~~Fully Assembled Electric Actuator~~

~~The electric actuator shall be tested for proper operation by stroking the actuator from the fully closed position to the fully open position a minimum of three times, per the manufacturer's written specification. The actuator should operate smoothly (no evidence of stick-slip movement, sometimes referred to as chatter) in both directions. If applicable, the actuator compensation chamber shall be tested per the manufacturer's written specification.~~

~~Testing of Valve/Actuator Assembly~~

~~After final assembly, each valve/actuator assembly (including override if fitted) shall be subjected to a functional and pressure test to demonstrate proper assembly and operation in accordance with the manufacturer's written specification. Equipment assembled entirely with previously hydrostatically tested~~

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~~equipment need only be tested to RWP. The functional test shall be performed by a qualified subsea valve/actuator manufacturer. All test data shall be recorded on a data sheet and shall be maintained by the subsea valve/actuator manufacturer for at least 5 years after date of manufacture. The test data sheet shall be signed and dated by the person(s) performing the functional test(s).~~

~~The subsea valve and actuator assembly shall meet the testing requirement of 7.10.4.2.2 and 7.10.4.2.3.~~

Marking

Subsea Valve Marking

~~Subsea valve assemblies shall be tagged with a nameplate, located on the valve body or nearest accessible location and contain the same information as in 6.5.~~

Subsea Valve Actuator/Operator Marking

~~The subsea valve actuator shall be marked as shown in Table 22.~~

Table 22—Marking for Subsea Valve Actuator/Operator

Marking		Application
1	Manufacturer's name or trademark	Nameplate
2	API 17D	Nameplate
3	Hydraulic cylinder maximum working pressure Hydraulic actuator	Nameplate and hydraulic actuator cylinder or
4	Manufacturer's part number	Nameplate
5	Serial or identification number	Nameplate and actuator cylinder or power unit housing

Subsea Valve and Actuator/Operator Assembly Marking

~~The subsea valve and actuator/operator assembly shall be marked as shown in Table 23.~~

Table 23—Marking for Subsea Valve and Actuator/Operator Assembly

Marking		Application
1	Manufacturer's name or trademark	Nameplate
2	API 17D	Nameplate
3	Assembly serial or identification number	Nameplate
4	Maximum water depth rating	Nameplate

Nameplates

~~Nameplates shall be attached after final coating of the equipment. Nameplates should be designed to remain legible for the design life of the product.~~

Flow Direction

~~All subsea valves that are designed to have unidirectional flow should have the flow direction prominently and permanently marked.~~

Underwater Safety Valves and Actuators

Underwater Safety Valves

General

~~USVs shall conform to the PSL requirements of API 17D in addition to specific safety valve quality requirements for actuated valves, in accordance with API 6A.~~

~~Record requirements and the accompanying data packages for manufactured USVs shall be in accordance with safety valve record requirements of API 6A.~~

USV Design

~~USVs shall be designed for and constructed of materials conforming to 7.10. Design criteria for USVs shall include maximum water depth.~~

~~The USV shall be of a fail-close design. The USV shall be designed to operate, without damage to the safety valve or safety valve actuator, when the valve is actuated open or closed, pressurized or depressurized, under any internal valve body pressure within its pressure rating, and under external pressure up to the maximum depth rating.~~

~~USVs may use end connectors as specified in Section 7. USVs may be of nonstandard bores and/or face-to-face lengths. End connectors shall meet all other requirements of this specification.~~

~~A USV valve may be a single loose valve or one valve in a multiple or block valve assembled body.~~

USV Validation

~~USVs shall satisfy the performance requirements specified in Section 5 and shall be validated as specified by API 6AV1 for the service class designated by the manufacturer. The USV shall be operated by a USV actuator during validation.~~

~~Validation of a single-unit USV shall validate a multiple or block-type valve for performance without additional validation testing, if it is of the same internal design as a USV within the manufacturer's product line that has passed the required validation testing, and if all other scaling requirements are satisfied. Scaling provision of Section 5 and API 6AV1 shall apply.~~

~~An independent test agency, as defined by API 6A and API 6AV1, shall conduct the API 6AV1 portion of USV validation and prepare the test report. The manufacturer shall submit a USV of the same basic design and materials of construction for the API 6AV1 validation tests. An independent test agency is not required for other USV validation per Section 5.~~

~~NOTE—It is not required that a single valve be consecutively tested to Section 5 and API 6AV1. The tests are not cumulative.~~

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~~USV Actuators~~

~~USV actuators shall be designed for and constructed of materials conforming to 7.10 and shall perform satisfactorily in the tests required of Section 5 and 7.10.4. The safety valve actuator's closing force shall be sufficient to close the USV when it is at the most severe design-closing condition specified by the manufacturer.~~

~~Permanently attached lock-open features shall not be permitted on USV actuators.~~

~~NOTE—The term “USV actuator” refers to a subsea actuator designated for use with an USV.~~

~~USV Acceptance Testing~~

~~All assembled USVs with USV actuators shall pass all applicable tests per API 17D as required in 7.10.4. All test data records shall be provided in accordance with safety valve record requirements of API 6A.~~

~~Low-pressure testing shall conform to API 17D in lieu of API 6A low-pressure testing.~~

~~USV Marking~~

~~In addition to the requirements of 6.5, valves and actuators used for USVs shall have separate nameplates affixed.~~

~~USVs shall be tagged with a nameplate in a visible location on the valve body or near the USV bonnet on a multiple- or block-type valve arrangement per Table 23 and contain the following information as a minimum:~~

~~manufacturer's name or trademark;~~

~~date;~~

~~PSL designation of the USV;~~

~~RWP of the USV;~~

~~temperature rating of the USV;~~

~~material class of the USV (including maximum H₂S partial pressure, if applicable);~~

~~sandy service class (per API 6AV1 validation);~~

~~unique identifier (serial number, PSL 3 and above);~~

~~API 17D USV~~

~~USV actuators shall be tagged with a nameplate in a visible location on the actuator body with the information listed in Table 22 with the designation “API 17D USV.”~~

~~Re-entry Interface~~

~~General~~

~~NOTE—A re-entry interface is used to provide an attachment interface on the tree or tubing head assembly for connection of:~~

~~a running tool used for installation and workover purposes;~~

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~~a tree cap or other pressure cap;~~

~~internal crown plugs, if applicable;~~

~~interface to other intervention hardware.~~

Design

Pressure Rating

~~The re-entry interface shall be rated to the tree working pressure as defined by 5.1.2.1.~~

Re-entry Interface Upper Connection/Profile

~~The connection shall also provide for passage of wireline tools and shall not limit the drift diameter of the tree bore.~~

Design Loads/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);~~

~~mechanical preloads;~~

~~riser bending and tension loads;~~

~~external environmental loads;~~

~~fatigue;~~

~~vibration;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads;~~

~~corrosion.~~

Subsea Tree Cap

General

Introduction

~~Vertical and horizontal trees use internally and externally attached tree caps. When internal caps are used, an external debris cap or cover may be installed to protect sealing surfaces and hydraulic couplers. Hydraulic couplers may be incorporated in the tree cap. These may be integral with the cap or externally attached.~~

Non-pressure-containing Tree Cap

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~~NOTE Non-pressure-containing tree caps protect the tree re-entry interface, hydraulic couplers, and vertical wellbores from possible environmental damage or undesired effects resulting from corrosion, marine growth, or potential mechanical loads.~~

~~Design of non-pressure-containing tree caps shall conform to Section 5 and is not addressed further in this specification.~~

~~If a parking spot for the debris cap is included in the tree, it shall provide a method of securing the cap. Load cases should include transportation, handling, installation, and accidental conditions, e.g. tree lowered too fast or dropped.~~

Pressure-containing Tree Cap

~~When the tree cap is used as a barrier, the system shall be designed to remove or isolate any trapped pressure from below or allow for the installation of a well control device before the tree cap can be removed.~~

Design

General

~~The provisions in 7.12.2 shall apply to pressure-containing tree caps. The design of this equipment shall conform to 5.1. The requirements given in 7.12.2.2 to 7.12.2.4 shall apply to both internally and externally attached tree caps.~~

Pressure Rating

~~The tree cap shall be rated to the tree working pressure as defined by 5.1.2.1.~~

Tree Cap Locking Mechanism

~~The tree cap locking mechanism shall be designed to contain the rated tree working pressure acting over the corresponding seal areas that interface with the upper tree connection. The tree cap locking mechanism shall include a secondary release feature or separate fishing profile.~~

~~NOTE Three types of tree cap are commonly used:~~

~~hydraulic, remote-operated;~~

~~mechanical, remote-operated;~~

~~mechanical diver/ROV operated.~~

Design Loads/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed) unless relief is provided as described in 5.1.2.1;~~

~~mechanical preloads;~~

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~~installation string bending and tension loads;~~

~~temperature variations;~~

~~external environmental loads;~~

~~fatigue assessment;~~

~~vibration;~~

~~trapped volumes and thermal expansion;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads;~~

~~corrosion;~~

~~dropped objects and snag loads.~~

~~Design and Functional Requirements~~

~~Installation Pressure Test~~

~~A means shall be provided to test the upper tree connection and tree cap seal(s) after installation.~~

~~Pressure Venting~~

~~A means shall be provided such that any pressure underneath the tree cap can be vented prior to removal.~~

~~Hydraulic Lock~~

~~A means shall be provided for the prevention of hydraulic lock during installation or removal of the tree cap.~~

~~Operating Pressure~~

~~Hydraulically actuated tree caps shall be capable of containing hydraulic release pressures of at least 25 % above normal operating release pressures if normal operating release pressure is inadequate to effect release of the connector. The manufacturer shall document both normal and maximum operating release pressures. The unlocking force shall be greater than the locking force. The values shall be documented by the manufacturer.~~

~~Secondary Release~~

~~Tree caps shall be designed with a secondary release method, which may be hydraulic or mechanical. Diver/ROV/remote tooling shall conform to API 17H. Hydraulic open and close control line piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if necessary for the secondary release to function.~~

~~External Position Indication~~

~~External tree caps shall be equipped with an external position indicator to show when the tree cap is fully locked.~~

~~Self-locking Requirement~~

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~~Hydraulic tree caps shall be designed for the following:~~

~~prevent unintentional release due to loss of hydraulic locking pressure, and~~

~~intentional release in the event of malfunction of the hydraulic locking pressure.~~

Materials

~~Materials shall conform to 5.2. Seal surfaces that engage metal-to-metal seals shall be inlaid with a corrosion-resistant material that is compatible with well fluids, seawater, etc.~~

~~NOTE—Overlays are not required if the base material is compatible with well fluids, seawater, etc.~~

Testing

General

~~The following test procedure shall apply to tree caps having either mechanical or hydraulic connectors.~~

~~Crown plugs associated with HXT tubing hangers or internal tree caps shall follow the same testing requirements as internal tree caps.~~

Validation

~~Validation of the tree cap shall conform to 5.1.7. In addition, the lockdown mechanism of an external tree cap shall be tested to a minimum of 1.5 times the RWP from below. The lockdown mechanism for an internal tree cap shall be tested to 1.0 times the RWP from above. Where access devices (e.g. poppet, shuttle, sliding sleeve, etc.) and chemical carriers are incorporated into the design, these shall meet the design performance qualification requirements as shown in Table 5.~~

Factory Acceptance Testing

~~Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Pressure-containing tree caps shall be tested in accordance with 7.8.3.2 and Table 6, as applicable.~~

Marking

~~The subsea tree cap shall be marked in accordance with 5.5.1. Pressure-containing tree caps shall include the additional marking information:~~

~~PSL;~~

~~RWP;~~

~~temperature rating;~~

~~material class of production bore;~~

~~material class of annulus bore.~~

Tree Cap Running Tool

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General

~~Tools for running tree caps may have some of the following functions:~~

~~actuation of the tree cap connector;~~

~~pressure tests of the tree cap seals;~~

~~relieve pressure beneath the tree cap;~~

~~injection of corrosion inhibitor fluid.~~

Design

Operating Criteria

~~The manufacturer shall specify the operating criteria for which the tree cap running/retrieval tool is designed.~~

~~Tree cap running/retrieval tools should be designed such that they function in the conditions/circumstances expected to exist during tree cap running/retrieving operations and well re-entry/workover operations. Specific operating criteria (design loads and angle limits, etc.) shall address the impact of vessel motions, resulting running string tensions and angles that can occur.~~

Design Loads/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);~~

~~mechanical preloads;~~

~~installation string bending and tension loads;~~

~~environmental loads;~~

~~fatigue;~~

~~vibration;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads;~~

~~thermal expansion (trapped fluids, dissimilar metals);~~

~~installation/workover overpull;~~

~~corrosion.~~

~~The manufacturer shall specify the loads/conditions for which the equipment is designed.~~

~~Tree Cap to Running Tool Interfaces~~

~~General~~

~~The interface between the tree cap and running tool shall be designed for release at a running string departure angle as documented by the manufacturer to meet the operational requirements. This release shall not cause any damage to the tree cap such that prevents meeting any other performance requirement nor present a risk of snagging or loosening the tree cap when removed at that angle.~~

~~The tree cap interface may consist of the following:~~

~~locking profile and connector;~~

~~re-entry seal;~~

~~extension subs or seals;~~

~~controls and instrumentation;~~

~~diver/ROV interfaces (for operation and pressure testing functions).~~

~~Control system and data gathering instrumentation conduits may pass through the tree running tool body.~~

~~Locking Profile and Connector~~

~~The tree cap running tool shall land and lock onto the locking profile of the tree cap and shall withstand the separating forces resulting from applied mechanical loads and when applicable the RWP of the tree as specified by the manufacturer. The tree cap running tool connector shall meet functional requirements set forth in 7.13.2.2.~~

~~Means shall be provided to prevent trapped fluid from interfering with the make-up of the hydraulic or mechanical running tool connector.~~

~~Tree Guide Frame Interface~~

~~Guidance and orientation with other subsea equipment should conform to or be an extension of the geometries specified in 7.14.2.1, when applicable to the design.~~

~~Secondary Release~~

~~Hydraulically actuated tree cap running tools shall be designed with a secondary release method that may be hydraulic or mechanical. Hydraulic open and close piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if needed for the secondary release to function.~~

~~Position Indication~~

~~Remotely operated tree cap running tools shall be equipped with an external position indicator suitable for observation by diver/ROV.~~

~~Factory Acceptance Testing~~

~~Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and~~

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~~locking mechanisms. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Pressure-containing tree cap running tools shall be tested in accordance with 7.8.3.2, as applicable.~~

~~FAT shall apply to both mechanical and hydraulic tree cap running tool connectors.~~

Marking

~~The subsea tree cap running tool shall be marked in accordance with 5.5.1. Pressure-containing tree cap running tools shall include the additional marking information:~~

~~RWP;~~

~~temperature rating;~~

~~material class.~~

Tree and Tubing Head Guide Frames

General

~~The tree or tubing head guide frame may interface with either a CGB or PGB (or GRA) to guide the equipment onto the subsea wellhead or tubing head. The frame may also provide a structural mounting for piping, flowline connection, control interfaces, work platforms, anodes, handling points, ROV docking/override panels, and structural protection both on surface and subsea for tree components. The tree guide frame provides an envelope and structural mounting for the control pod, when used.~~

~~The envelope shall allow for control pod installation, retrieval, and access. The provisions in this subsection shall apply if a retrievable choke module is located on the subsea tree.~~

~~Design and associated load testing shall conform to the requirements in 5.1.3.6. and the manufacturer's written specification.~~

~~The guide frame may address structural protection of pressure-containing components as agreed to between the manufacturer and the user/purchaser.~~

~~The tree guide frame should have a guidance structure that interfaces with the CGB or posts from the PGB (GRA) to provide initial orientation and alignment. It shall be designed to provide alignment to protect seals, control line stabs, and seal surfaces from damage in accordance with the manufacturer's written specification.~~

Design

Guidance and Orientation

~~For guideline configurations, interfacing shall conform to the dimensions shown in Figure 10 a), unless the orientation system requires tighter tolerances. Guidepost funnels are typically fabricated from 10³/₄ in. OD × 0.5 in. wall (273 mm OD × 12.5 mm wall) pipe or tubulars. Spatial orientation (heading (yaw) and vertical tilt (pitch-sway) and fixed X-Y-Z position) tolerance is typically ±0.5° when mated with the guideposts. The manufacturer shall address methods to achieve more precise orientation or alignment when required.~~

~~For guidelineless configurations, the outermost diameter of the re-entry funnel should be no less than 1.5 times the diameter of the component it is capturing. The re-entry funnel's angle should be no shallower than 40° with respect to horizontal.~~

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~~Once captured, the funnel and inner cylinder shall be designed to allow for equipment re-entry at tilt angles up to 3° (relative misalignment between mating equipment) in any orientation, and subsequently assist in righting the captured component to vertical.~~

~~Portions of the re-entry cone may be scalloped to accommodate rough alignment and/or guidelineless re-entry of adjacent equipment whose capture funnel can intersect with the main funnels because of space constraints. This is acceptable, although it takes away from the re-entry properties of the funnel in the scalloped-out area. Its practice should be carried out with sound engineering judgement comparing operational limits lost versus size and mass (weight) gained. Ideally, scalloped funnels should be minimized or covered wherever practical.~~

~~Since funnel-up re-entry designs are typically cylindrical and conical in nature, horizontal resting pads or a beam structure should be incorporated in the frame's design to provide a sound, flat surface that can firmly sit on spider beams to support or suspend the equipment.~~

~~When spatial orientation is required, funnel-up funnels and capture equipment may also feature Y-slots and orienting pins. The upper portion of the Y-slot should be wide enough to capture mating pins within $\pm 7.5^\circ$ of true orientation. The Y-slot should then taper down to a width commensurate with the pin to provide orientation to within $\pm 0.5^\circ$ (like the angular orientation provided by guideposts and funnels). Typically, there are two or four orienting pins, each with a minimum diameter of 4.0 in. (101.6 mm) in diameter [see Figure 10 b)].~~

~~Other orientation methods, such as orienting helixes or indexing devices (ratchets, etc.) shall be acceptable. All designs shall allow for the 3° tilt re-entry requirement.~~

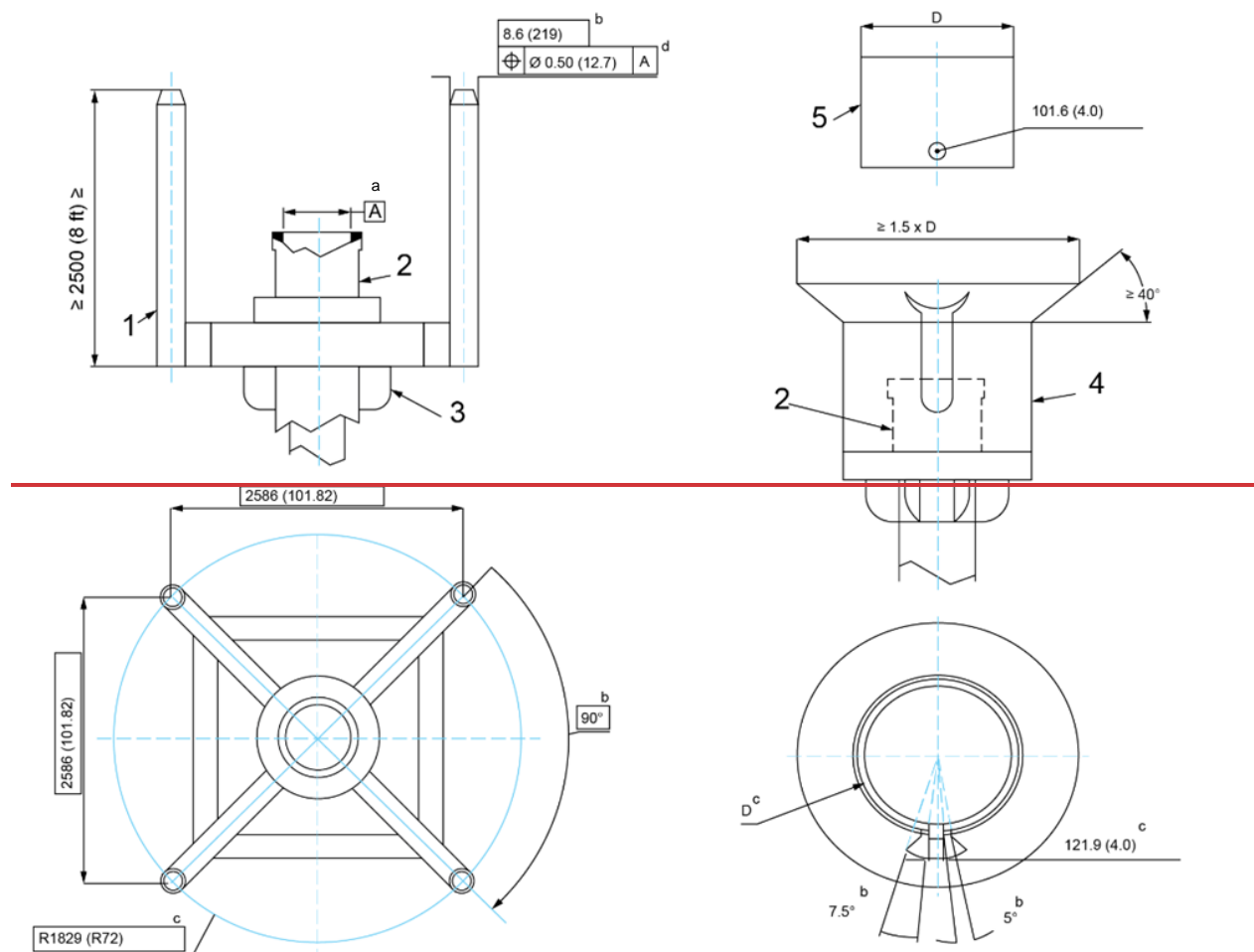
~~Tree or tubing head assembly connector may be able to retain a wellhead ring gasket during installation or retrieval, or re-entry design with a wellhead ring gasket pre-placed on the wellhead or tubing head. The connector and guide funnel angles should prevent contact with the ring gasket, when placed in the connector or on top of the mandrel or hub, during installation. This includes avoiding contact with isolation sleeves or stab mandrel.~~

~~Funnel-down orientation methods may include helixes, indexing devices, or circumferential alignment pins/posts.~~

~~Orientation should initially allow a wide enough capture within $\pm 7.5^\circ$ of true orientation, then refine the alignment down to an orientation to within $\pm 0.5^\circ$. Whatever the orienting method, it is necessary that the design allow for the 3° tilt re-entry requirement.~~

~~Dimensions in inches (millimeters) unless otherwise indicated~~

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a) Permanent Guidebase and Guideposts

b) Guidelineless Funnel-up

Key

guidepost

wellhead (high-pressure) housing

PGB

guide funnel

wellhead connector

Cumulative tolerances between all interfacing components shall be less than or equal to the positional tolerance shown.

Typical

Reference dimension

See ASME Y14.5 for tolerance explanation.

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~~NOTE—Guideposts positional tolerances are determined relative to the wellhead (high-pressure) housing bore (Datum—A-); method of measurement to be specified by the manufacturer.~~

Figure 10—Tree Guide Frames

Handling

~~Methods should be provided to allow handling of the assembled tree complete with test skid.~~

~~Trees shall accommodate fastening for transportation, including sea fastening, meeting the requirements of 5.5.2 and 7.21.1.3.5.~~

Design Load/Conditions

~~The guide funnel should be capable of supporting the full weight of the stacked tree, running tool, and EDP, unless landing pads are provided.~~

~~Depending on the environment in which the tree is being used, the structure may be required to extend from the bottom of the tree to the top of the tree to provide protection from installation loads and snag loads.~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~guideline tension;~~

~~flowline reaction loads;~~

~~snag loads;~~

~~dropped object loads (see API 17A);~~

~~impact loads/fishing-gear loads (see API 17A);~~

~~installation loads and intervention loads;~~

~~piping and connection loads (due to frame deflection);~~

~~handling and shipping loads.~~

Intervention Interfaces

~~Provision for ROV access to relevant ROV functions shall be provided.~~

~~Subsea intervention fixtures attached to the tree guide frame shall be in accordance with API 17H.~~

~~The frame design shall not impede access or observation, as appropriate, by divers/ROV of tree functions and position indicators.~~

Validation

~~Interface testing of guide frame guidance provisions in 7.14.2.1 shall be conducted to verify four-post or guidelineless alignment. A wellhead connector and mandrel or other centralizing means shall be used during the test. Test results shall be in accordance with the manufacturer's written specifications.~~

~~Tree Running Tool~~

~~General~~

~~NOTE—The function of a hydraulic or mechanical tree running tool is to suspend the tree during installation and retrieval operations from the subsea wellhead and to connect to the tree during workover operations. It may also be used to connect the completion riser to the subsea tree during installation, test, or workover operations. A subsea wireline/coil tubing BOP or other tool packages may be run between the completion riser and tree running tool.~~

~~The requirement for soft landing systems should be evaluated.~~

~~Operating Criteria~~

~~The user/purchaser shall specify the operating criteria necessary for the tree installation. The manufacturer shall document the operating limits for which the tree running/retrieval tool is designed.~~

~~The tree running tool may provide a pressure barrier to allow for pressure testing an internal tree cap, crown plug, or swab valve from above.~~

~~Tree running/retrieval tools should be designed to be operable in the conditions/circumstances expected to exist during tree running/retrieving operations and well re-entry/workover operations. Specific operating criteria (design loads and angle limits, etc.) should include the maximum surface vessel motions and resulting maximum running string tensions and angles that can occur.~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed, unless relief is provided as described in 5.1.2.1);~~

~~mechanical preloads;~~

~~external bending and tension loads from intervention equipment (see API 17G);~~

~~environmental loads;~~

~~fatigue assessment;~~

~~ROV impact loads;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads;~~

~~IWOCS equipment loading (trapped fluids, dissimilar metals);~~

~~installation/workover overpull.~~

~~The manufacturer shall state whether the basis of load ratings is stress limits or seal separation limits.~~

~~Tree Interface~~

~~General~~

~~The interface between the tree running tool and tree shall be designed for emergency release at a running string departure angle as specified by the manufacturer or the user/purchaser. This release shall not cause any damage to the subsea tree such that prevents meeting any other performance requirement.~~

~~The tree interface shall consist of four main component areas:~~

~~locking profile and connector;~~

~~re-entry seal, where applicable;~~

~~extension subs or seals, where applicable;~~

~~controls and instrumentation, where applicable.~~

~~NOTE—For use with dynamically positioned rigs, it is particularly important that the connector have a high-angle release capability and that the connector can be quickly unlocked. In some systems, the EDP connector design can meet these requirements.~~

~~The manufacturer and/or user/purchaser shall specify the angle and unlocking time.~~

~~Locking Profile and Connector~~

~~The tree running tool shall land and lock onto the locking profile of the tree re-entry hub and shall withstand the separating forces resulting from applied mechanical loads and any pressure loads from a re-entry seal, if present as specified by the manufacturer. The tree running tool connector shall meet functional requirements specified in 7.8.3.~~

~~Means shall be provided to prevent trapped fluid from interfering with make-up of the hydraulic or mechanical connector.~~

~~Re-entry Seal~~

~~The pressure-containing capability of this seal shall be at least equal to the tree RWP or the maximum anticipated control pressure of the downhole safety valve, whichever is greater, if the SCSSV control circuit(s) is encapsulated by this seal, unless relief is provided as described in 5.1.2.1.~~

~~Extension Subs or Seals~~

~~Extension subs or seals (if used) shall engage the mating surfaces in the upper tree connection for the purpose of isolating each bore. The seal mechanism shall have a primary and backup seal.~~

~~In multi-bore applications that use a re-entry seal as specified in 7.15.4.3, each extension sub or seal shall be designed to withstand an external pressure as specified by the manufacturer.~~

~~Controls and Instrumentation~~

~~Control system and data gathering instrumentation conduits may pass through the tree running tool body. Specific designs and selection of component materials are the responsibility of the manufacturer.~~

~~Intervention Interface~~

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~~The tree running tool shall interface with one or more of the following:~~

~~drilling riser system;~~

~~OWIRS or TBIRS interfaces (see API 17G);~~

~~wire rope deployment system.~~

~~Guidance and Orientation~~

~~Guidance and orientation with other subsea equipment shall conform to or be an extension of the geometries specified in 7.14.2.1.~~

~~Control System Interface~~

~~If the tree running tool incorporates the intervention interface, the protocol should be transferred to the workover control system (see API 17G5).~~

~~Secondary Release~~

~~Hydraulically actuated tree running tool connectors shall be designed with a secondary release method. Hydraulic open and close control line piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if required for the secondary release to function.~~

~~Position Indication~~

~~Remotely operated tree running tool connectors shall be equipped with an external position indicator suitable for observation by diver/ROV.~~

~~Materials~~

~~Tree running tool portions that can be exposed to wellbore fluids shall be made of materials conforming to 5.2.~~

~~Factory Acceptance Testing~~

~~Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Pressure-containing tree running tools shall be tested per 7.8.3.2, as applicable.~~

~~Marking~~

~~The subsea tree running tool shall be marked in accordance with 5.5.1. Pressure-containing subsea tree running tools shall include the additional marking information:~~

~~RWP.~~

~~Tree, Tubing Head, and Completion Guidebase Piping~~

~~General~~

~~The term "piping" is used to encompass the requirements for all pipe, fittings, or pressure conduits, excluding valves and chokes, from the bores of the tree to the flowline connection(s) leaving the subsea~~

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~~tree. The piping may be used for production, pigging, monitoring, water, gas or chemical injection, service or test of the subsea tree.~~

~~Design~~

~~Allowable Stresses~~

~~Outboard tree piping shall conform to the requirements of an existing, documented piping code, and, as a minimum, the design RWP of the outboard piping shall be equal to the RWP of the tree. Inboard piping designs shall conform to 5.1.~~

~~In all cases the following may apply:~~

~~allowable stress at working pressure;~~

~~allowable stress at test pressure;~~

~~external loading;~~

~~tolerances;~~

~~corrosion/erosion allowance;~~

~~temperature;~~

~~wall thinning due to bending;~~

~~vibration.~~

~~Operating Parameters~~

~~Operating parameters for tree piping shall be based on the service, temperature, material, and external loading on each line. Tree piping may be designed to flex to enable connectors to stroke or to compensate for manufacturing tolerances.~~

~~NOTE—Attention is to be given to piping downstream of chokes, due to possible high fluid velocities and low temperatures (see Section 5).~~

~~Tree Piping Flowloops~~

~~Tree piping flowloops may be fabricated using forged fittings, pre-bent sections, or may be formed in a continuous piece.~~

~~Bends that are being used in H₂S service shall conform to the requirements of NACE MR0175 (all parts). Induction-bent piping shall be manufactured in accordance with qualified procedures and suppliers.~~

~~Pigging~~

~~The manufacturer shall document the ability to pig tree piping where such piping is intended to be piggable. Demonstration of the piggability of the intended piping shall be agreed to by the user/purchaser and the manufacturer.~~

~~Flowline Connector Interface~~

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~~The tree piping and flowline connector, when required by the system, shall be designed to allow flexibility for connection in accordance with the manufacturer's written specification. Alternatively, the flexibility may be built into the interface piping system. In the connected position, the combination of induced pipe tension, permanent bend stress, thermal expansion, wellhead deflection, and the specified operating pressure shall not exceed the allowable stress as defined in 7.16.2.1. Stresses induced during make-up may exceed the level in 7.16.2.1 but shall not exceed material minimum yield strength.~~

~~Pressure/temperature transducers and chemical injection penetrations located on inboard piping shall be equipped with flanged or studded outlets that conform to 7.1 or 7.4.~~

~~Penetrations located on outboard piping may be either flanged, threaded, or weld on bosses. Threaded connections shall conform to 7.3, flanged connections shall conform to 7.1 or 7.4, and weld on bosses shall conform to ASME B16.11.~~

~~Safeguarding of penetrator connections may be provided by either locating ports in protected areas or by fabricating protective covers as agreed to between the manufacturer and the user/purchaser.~~

~~Specification Break~~

~~The location of the specification break between the requirements of this specification (on the tree or CGB) and that of the flowline/pipeline is specifically defined below.~~

~~The following shall apply for tree and tubing head/CGB specification breaks.~~

~~Design code—All piping shall be designed in accordance with 7.16.2.1. End connections/fittings for both inboard and outboard piping shall be designed in accordance with 7.1 through 7.4, regardless of piping code used.~~

~~Testing—All testing for inboard piping shall conform to the requirements in accordance with 5.4. All testing for outboard piping shall be in accordance with the specified piping code.~~

~~Materials—Materials for inboard piping shall conform to 5.2. Material for outboard piping and pipe fittings shall conform to the requirements of the specified piping code. For example, wall thickness calculated using ASME B31.3 requires the use of ASME B31.3 allowable material stresses.~~

~~Welding—Welding of inboard piping shall be in accordance with 5.3. Welding of outboard piping shall conform to the specified piping code or 5.3, whichever is appropriate.~~

~~Flowline Connections~~

~~Flowline Connection Support Frame~~

~~General~~

~~The flowline connection shall be supported by an appropriately designed support frame that shall be attached to the subsea tree and/or subsea wellhead. The support frame shall be attached to the subsea wellhead (high pressure) housing, the PGB, GRA or CGB, the tree and/or tree frame, or other structural member suitable for accommodating all expected loading conditions.~~

~~Design~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~flowline pull-in, catenary, and/or drag forces during installation;~~

~~flowline alignment loads (rotational, lateral, and axial) during installation;~~

~~flowline reaction loads due to residual stresses, flowline weight, thermal expansion/contraction, and operational/environmental effects;~~

~~reactions from environmental loads on flowline connector running/retrieval and maintenance tools;~~

~~flowline reaction/alignment loads when the tree is pulled for service;~~

~~flowline/umbilical overloads;~~

~~wellhead deflection;~~

~~internal and external pressures (operational and hydrostatic/gas tests).~~

~~Functional Requirements~~

~~The flowline connector support frame shall transmit all loads imparted by the flowline and umbilical into a structural member to ensure that:~~

~~tree valves and/or tree piping are protected from flowline/umbilical loads that could damage these components;~~

~~alignment of critical mating components is provided and maintained during installation;~~

~~tree can be removed and replaced without damage to critical mating components.~~

~~The flowline connector support frame shall be designed to avoid interfering with the BOP stack.~~

~~Flowline Connectors~~

~~General~~

~~NOTE The flowline connector and its associated running tools provide the means for joining the subsea flowline(s) and/or umbilical(s) to the subsea tree. In some cases, the flowline connector also provides means for disconnecting and removing the tree without retrieving the subsea flowline/umbilical to the surface.~~

~~Flowline connectors shall fall into one of the following categories:~~

~~manual connectors operated by divers or ROVs;~~

~~hydraulic connectors with integral hydraulics (see API 17R);~~

~~mechanical connectors with the actuators contained in a separate running tool (see API 17R).~~

~~Design~~

~~Flowline connectors shall have an RWP equal to the RWP of the tree. The design of the flowline connector shall be in accordance with API 17R and the stress allowables for the selected outboard piping code with~~

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~~respect to movement and alignment conditions. Integral hydraulics shall be in accordance with API 17R and 5.4.7.~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~flowline pull in, catenary, and/or drag forces during installation;~~

~~flowline alignment loads (rotational, lateral, and axial) during installation;~~

~~flowline reaction loads due to residual stresses, flowline weight, thermal expansion/contraction, and operational/environmental effects;~~

~~reactions from environmental loads on flowline connector running/retrieval and maintenance tools;~~

~~flowline reaction/alignment loads when the tree is pulled for service;~~

~~flowline/umbilical overloads;~~

~~wellhead deflection;~~

~~internal and external pressures (operational and hydrostatic/gas tests);~~

~~load created by a loss of station-keeping;~~

~~cyclic loads from vortex-induced vibration.~~

~~The flowline connector shall ensure sealing under all pressure and external loading conditions specified.~~

~~When actuated to the locked position, hydraulic flowline connectors shall remain self-locked without requiring that the hydraulic pressure be maintained. Connectors shall be designed to prevent loosening due to cyclic installation and/or operational loading. This shall be achieved by a mechanical locking system or backup system or other demonstrated means. Mechanical locking devices shall incorporate a release mechanism in the event of malfunction.~~

~~Dimensions~~

~~The dimensions of the flowline connector's flow passages should be compatible with the drift diameters of the flowlines.~~

~~When pigging capability is specified, the flowline connector flow passages should be configured to provide transitions and internal geometry compatible with the type(s) of pig specified by the manufacturer.~~

~~The end connections used on the flowline connector (flanges, clamp hubs, or other types of connections) shall conform to 7.1 through 7.6. Preparations for welded end connections may be done in accordance with 7.1.2.6 or API 6A.~~

~~The termination interface between the flowline connector and the flowline shall conform to the requirements of 7.1 through 7.4 at the flowline connector side, and to the requirements of the specified piping code on the flowline side.~~

~~Functional Requirements~~

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~~The flowline connector and/or its associated running tool(s) should provide positioning and alignment of mating components such that connection can be accomplished without damage to sealing components or structural connection devices. Seals and sealing surfaces shall be designed such that they can be protected during installation operations.~~

~~Primary seals on flowline connectors shall be metal-to-metal. Glands for the metal seals shall be inlaid with GRM unless the base material is corrosion resistant.~~

~~Where multiple bore seals are enclosed within an outer environmental or secondary seal, bidirectional bore seals shall be provided to prevent cross-communication between individual bores.~~

~~The flowline connection system shall provide means for pressure testing the flowline and/or umbilical connections following installation and hook-up.~~

~~The flowline connector shall have as a minimum the same RWP as the subsea tree. Means shall be provided for pressure testing the tree and all its associated valves and chokes without exceeding the test pressure rating of the flowline connector.~~

~~The flowline connector should have a visual means for external position verification.~~

~~Flowline connector components located downstream of the choke may require a lower temperature rating than the tree system due to J-T cooling effects.~~

Testing

General

~~NOTE This section covers the testing of the flowline connection system, which includes the flowline connection support frame, the flowline connector, the flow loops, and associated running/retrieval and maintenance tools.~~

Validation

~~Tests shall be conducted to verify the structural and pressure integrity of the flowline connection system under the rated loads specified by the manufacturer in accordance with API 17R. Additionally, testing shall include:~~

~~simulated operation of all running/retrieval tools under loads typical of those expected during actual field installations;~~

~~simulated pull in or catenary flowline loads (as applicable) during flowline installation and connection;~~

~~removal and replacement of primary seals for flowline connectors for remotely replaceable seals;~~

~~functional tests of required running/retrieval and maintenance tools;~~

~~maximum specified misalignment;~~

~~connection qualification test including torsion, bending, pressure, and temperature (see API 17R).~~

~~The manufacturer shall document successful completion of the above tests.~~

Factory Acceptance Testing

~~FAT shall be as specified as follows.~~

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~~Structural components—All mating structural components shall be tested in accordance with the manufacturer's written specification for fit and function using actual mating equipment or test fixtures.~~

~~Pressure-containing components—Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Flowline connectors shall be hydrostatically tested in accordance with the specified piping code using the subsea tree's RWP as the piping code's design pressure. In addition, the flowline connector shall be tested in accordance with 7.8.3.2, as applicable.~~

~~Running tools—Testing shall be conducted in accordance with the manufacturer's written specification to confirm the proper function of the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Ancillary Equipment Running Tools~~

~~Operating Criteria~~

~~The manufacturer shall document the operating criteria, clearance and access criteria for ancillary equipment, and their running/retrieval tools as it pertains to the mounting on the subsea tree. Ancillary equipment may include control pods, retrievable chokes, and flowline connection equipment.~~

~~Running/retrieval and testing tools should be designed such that they are operable in the conditions/circumstances expected to exist during running/retrieving operations and workover operations. Specific operating criteria (design loads and angle limits, etc.) should include the maximum surface vessel motions and resulting maximum running string tensions and angles that can occur.~~

~~Loads and Component Strength~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~internal and external pressure;~~

~~pressure separation loads, which shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);~~

~~mechanical preloads;~~

~~running string bending and tension loads;~~

~~environmental loads;~~

~~fatigue assessment;~~

~~vibration;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads;~~

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~~installation/workover overpull.~~

~~The manufacturer shall specify the loads/conditions for which the equipment is designed. The manufacturer shall document the load/capacity for their running tool.~~

~~Running Tool Interfaces~~

~~The running tool shall be capable of connection, functioning, and disconnection at the maximum combined loads, as specified in 7.18.2.~~

~~Control and/or test connections that pass through the interface shall retain their pressure integrity at the maximum combined load rating.~~

~~Guidance and Orientation~~

~~If the subsea tree structure is used for alignment and orientation, running tool guidance structures shall conform to or be an extension of the geometries specified in 7.14.2.1. Independent guidance and orientation shall be designed in accordance with the manufacturer's written specification.~~

~~Tree-mounted Hydraulic/Electric/Optical Control Interfaces~~

~~General~~

~~Tree-mounted hydraulic/electric/optical control interfaces covered by this specification shall include all pipes, hoses, electric or optical cables, fittings or connectors mounted on the subsea tree, flowline base or associated running/retrieving tools for the purpose of transmitting hydraulic, electric, or optical signals or hydraulic or electric power between controls, valve actuators, and monitoring devices on the tree, flowline base or running tools and the control umbilical(s) or riser paths.~~

~~Design~~

~~Pipe/Tubing/Hose~~

~~Allowable stresses in pipe/tubing shall be in accordance with ASME B31.3. Hose design shall conform to SAE J517 and shall include validation to SAE J343. Design shall account for the following:~~

~~allowable stresses at working pressure;~~

~~allowable stresses at test pressure;~~

~~external loading;~~

~~collapse;~~

~~manufacturing tolerances;~~

~~fluid compatibility;~~

~~flow rate;~~

~~corrosion/erosion;~~

~~temperature range;~~

~~vibration.~~

Size and Pressure

~~All pipe/tubing/hose shall be minimum of $\frac{3}{16}$ -in. inner diameter. Sizes and pressure ratings of individual tubing runs shall be determined to suit the functions being operated. Injection lines, downhole hydraulic, connector/gasket seals test lines, pressure monitor lines, or any line that by design is exposed to wellbore fluids shall be rated at the working pressure of the tree. SCSSV lines shall be rated at the specified SCSSV operating pressure (see 5.1.2.1 and 9.1.7 for additional information).~~

Optical Cables and Cable Penetrations

~~Optical terminations and feed-through systems shall include penetrations validated to prevent fluid leakage. Optical penetrations into pressure-containing cavities or piping systems shall be qualified for the full differential pressure across the penetration. Optical fibers run in fluid-filled hoses shall include sufficient internal fiber slack length to prevent fiber tensioning under the expected load conditions.~~

Envelope

~~All pipe/tubing/hose/electric or optical cable shall be within the envelope defined by the guide frames of the tree, running/retrieving tool, or the flowline base.~~

Routing

~~Small-bore [less than 1.0 in. (25.4 mm) ID] tubing runs should be planned to use the minimum number of fittings or welded joints. In-line threaded couplings and unions to extend line length shall not be allowed.~~

~~The bend radius of cold-bent tubing shall not exceed the requirements of NACE MR0175 (all parts) for cold-working. Cold bends shall be in accordance with ASME B31.3. Tubing that runs to hydraulic tree connectors, running tool connectors, and flowline connectors shall be accessible to divers/ROV/remote tooling, such that it can be disconnected, vented, or cut, in order to release locked-in fluid and allow mechanical override.~~

~~Electrical cables should be routed such that any water entering the compensated hoses moves away from the end terminations by gravity. Electrical signal cables shall be screened/shielded to avoid cross talk and other interferences.~~

Small-bore Tubing and Connections

~~General requirements for small bore [less than 1.0 in. (25.4 mm) ID] tubing and connections are as follows.~~

~~Quality requirements for small-bore tubing and connections shall be to the manufacturer's written specification.~~

~~Hydraulic couplers, end fittings, and couplers shall meet or exceed requirements of the existing piping code used for the piping/tubing/hose design in 7.19.2.1. Tubing shall be seamless.~~

~~Threaded connections shall be in accordance with 7.3.~~

~~For a line that penetrates the wellbore (for example, chemical injection or SCSSV):~~

~~if located inboard of two isolation valves, of which one is remotely operated, connections shall be full-penetration butt welds as specified in 5.3.1;~~

~~if located outboard of two isolation valves, of which one is remotely operated, connections may be full-penetration butt welds, fittings, or socket welds.~~

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~~For a line that does not penetrate the wellbore, connection may be a fitting or socket weld.~~

~~Tubing and hose fitting shall be tested to verify that they are not isolated from the cathodic protection system in accordance with 5.4.8.~~

~~Electrical Connectors~~

~~Electrical connection interfaces made up subsea shall prevent the ingress of water or external contaminants. The retrievable half of conductive type electrical connectors should contain seals, primary compensation chambers, penetrators, springs, etc. The design of the nonretrievable half shall address the effects of corrosion, calcareous growth, cathodic protection, etc.~~

~~Optical Connectors~~

~~Optical connection interfaces made up subsea shall feature pressure-compensated chambers in which the final optical fiber connections are engaged. The configuration shall prevent the ingress of water or external contaminants that can potentially interfere with the optical fiber engagement. Optical connectors should ideally include an automatic mechanism to wipe the face of the fibers prior to final engagement of the mating fibers.~~

~~Control Line Stabs/Couplers~~

~~As a minimum, control line stabs for the SCSSV, PMV(s), PWV, and AMV shall be designed so as not to trap pressure when the control stabs are separated except where allowed in 9.1.9.~~

~~Both vented and nonvented control stabs should be designed to minimize seawater ingress when connected/disconnected. They shall be capable of disconnection at the rated internal working pressure, without detrimental effects to the seal interface. The half containing the seals shall be in the retrievable assemblies. In addition to the internal working pressure, the control stabs shall be designed to withstand external pressure at manufacturer's rated water depth. Stabs shall be capable of sealing at all pressures within their rating, in both the mated and unmated (nonvented type) condition, except as noted herein.~~

~~NOTE 1 — Venting control stab connections are primarily intended as a well control feature of a subsea tree when the tree is controlled by direct or a piloted hydraulic control system. Subsea tree interface designs with individual hydraulic control lines often feature poppet connections to protect the line from debris and seawater ingress. If the control stab connection were separated during a severe damage or emergency disconnect event before hydraulic line pressure can be bled down, the individual stab's poppet can trap hydraulic control line pressure behind the poppet, preventing the above-mentioned fail-closed safety devices from closing. The venting control stab requirement is intended to circumvent the trapped pressure possibility.~~

~~NOTE 2 — The venting control stab requirement is not intended for other control system configurations or their internal interface connections providing a vent feature is included to allow fail-closed safety devices to close. API 17F provides guidance on proper avoidance of trapped hydraulic pressure situations for these control systems.~~

~~Coupling Stab and Receiver Plate Assembly~~

~~Multi-port hydraulic receiver plates, as used at the control pod, tree cap, tree running tool, etc., shall have an alignment system to ensure correct alignment of hydraulic couplers prior to engagement of their seals. The stab's couplers shall be mounted in a manner to accommodate any misalignment during make-up. The alignment shall also not allow miscommunication between umbilical lines and tree plumbing, i.e. shall align in one orientation only.~~

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~~The coupling stab and receiver plate assembly shall be designed to withstand the RWP applied simultaneously in every control path without deforming to the extent that any other performance requirement is affected in accordance with the manufacturer's written specification. In addition, when nonpressure balanced control couplers are used, the manufacturer shall determine and document the rated water depth at which coupler plate/junction plate can decouple the control couplers without deformation damage to the plate assemblies with zero pressure inside the couplers. The manufacturer shall determine and document the force required for decoupling at the rated water depth with zero pressure inside the couplers.~~

~~Proprietary coupler stab and receiver plate designs shall meet the test requirements in 7.19.5.~~

~~Secondary Release~~

~~Where horizontal hydraulic/electric/fiber optic penetrations are required between HXT and TH, a secondary release method shall permit disengagement of the penetrator in the event of a malfunction that prevents normal (linear) retraction of the stem.~~

~~Assembly Practice~~

~~Cleanliness During Assembly~~

~~Practices should be adopted during assembly to maintain tubing/piping/fittings cleanliness.~~

~~Flushing~~

~~After assembly, all tubing runs and hydraulically actuated equipment shall be flushed to meet the cleanliness requirements of SAE/AS 4059. The class of cleanliness shall be as agreed between the manufacturer and the user/purchaser. Final flushing operations shall use a hydraulic fluid compatible with the fluid being used in the field operations. Equipment shall be supplied filled with hydraulic fluid. Fittings, hydraulic couplings, etc., shall be blanked off after completion of flushing/testing to prevent particle contamination during storage and retrieval.~~

~~Materials~~

~~Corrosion~~

~~Pipe/tubing and end fittings, connectors and connector plates shall be made of materials that can withstand atmospheric and seawater corrosion.~~

~~Pipe/tubing/hoses in contact with wellbore fluids or injected chemical shall be made from materials compatible with those fluids.~~

~~NOTE—Recommended test procedures can be found in Annex K.~~

~~Seal Materials~~

~~Seal materials shall be suitable for the type of hydraulic control fluid being used in the system. Seals in contact with wellbore fluids or injected chemicals shall be made of materials compatible with those fluids.~~

~~Testing~~

~~Small-bore Tubing, Hoses, and Connections~~

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~~Testing of assembled pipe/tubing/hose and end fittings, connectors, and connector plates exposed to production pressure shall conform to 5.4, except that the test pressure shall not exceed the test pressure of the lowest pressure-rated component in the system in accordance with 5.4.7. Testing of assembled pipe/tubing/hose and end fittings, connectors, and connector plates carrying control fluid shall be in accordance with ASME B31.3 as specified in 5.4.7.~~

~~Hydraulic couplers, end fittings, couplings, tubing, and hose fittings shall be tested to verify that they are electrically connected to the cathodic protection system.~~

~~Stab/Receiver Plate Assembly~~

~~The stab/receiver plate assembly shall be tested to RWP applied simultaneously in every control path in accordance with the manufacturer's written specification.~~

~~Connector Plate Marking~~

~~Each connector plate shall be permanently marked with the following minimum information:~~

~~its part number;~~

~~path designation numbers or letters identifying each path/connector.~~

~~All part numbers, path designations, operating pressures of each path, and other pertinent information should be included in the design documentation.~~

~~Subsea Chokes and Actuators/Operators~~

~~General~~

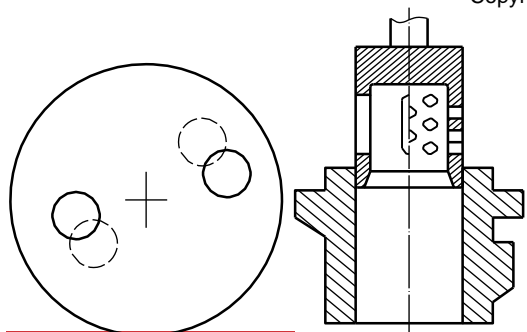
~~In 7.20 are covered subsea chokes, actuators, and their assemblies used in subsea applications. It provides requirements for the choke and actuator/operators assembly performance standards, sizing, design, materials, testing, marking, storage, and shipping. Subsea choke applications are production, gas lift, and injection.~~

~~The design of the tree system may include requirements for replacement of high-wear items of the subsea choke, including isolation prior to retrieval and testing following reinstallation.~~

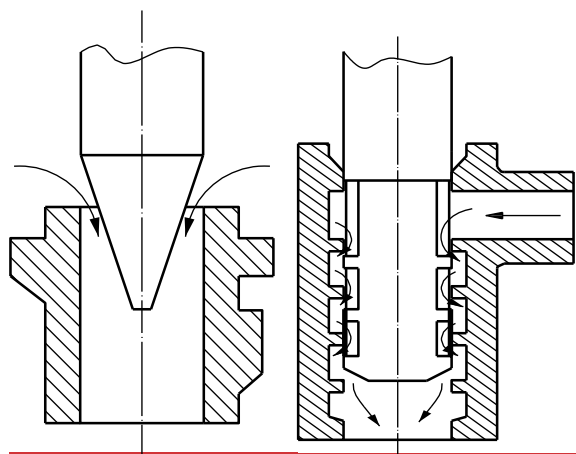
~~Subsea Chokes~~

~~Choke Configuration~~

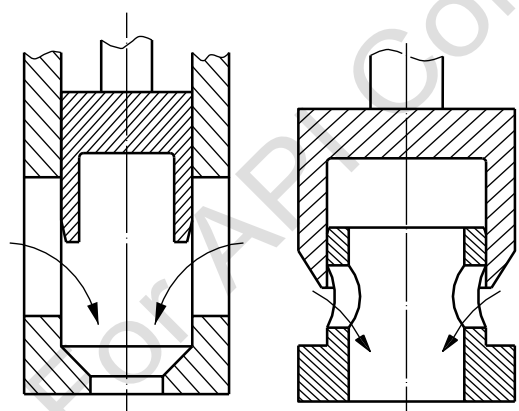
~~Examples of orifice configurations are shown in Figure 11.~~



Rotating Discs — d) — Sliding Sleeve and Cage



Needle and Seat e) — Multi-stage/Cascade



Plug and Cage f) — Cage and External Sleeve

Figure 11—Choke Common Orifice Configurations

Design

General

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~~Subsea chokes shall be designed in accordance with the general design requirements of 5.1. Choke capacity should be in accordance with the requirements of ISA 75.01.01 and ISA 75.02.01 for anticipated or actual production flow rate and fluid conditions (pressures, temperatures, and flow media).~~

~~NOTE—The information shown in Annex B illustrates purchasing guidelines to the choke manufacturer for the sizing of the choke.~~

~~Testing shall validate specific choke and choke actuator/operator designs manufactured under this specification (see 5.1.7).~~

Design and Operating Parameters

Manufacturers shall document the following design and operating parameters of the subsea choke:

~~maximum pressure rating;~~

~~maximum reverse differential pressure rating;~~

~~maximum $C_v(K_v)$;~~

~~temperature rating;~~

~~maximum;~~

~~minimum;~~

~~PSL;~~

~~material class;~~

~~type of choke (retrieval style):~~

~~nonretrievable;~~

~~diver assist retrievable;~~

~~tool retrievable;~~

~~functional style of choke:~~

~~adjustable choke prepared for manual operator;~~

~~adjustable choke prepared for hydraulic actuator;~~

~~adjustable choke prepared for electric actuator;~~

~~end connections:-~~

~~size and pressure rating;~~

~~ring gasket size;~~

~~type of operation:~~

~~ROV;~~

~~diver assist;~~

~~water depth rating.~~

~~Pressure Rating~~

~~For chokes having end connections with different pressure ratings, the rating of lowest-rated pressure-containing part shall be the rating of the subsea choke. The RWP of the subsea choke shall be equal to or greater than the RWP of the subsea tree.~~

~~Temperature Rating~~

~~All pressure-containing components of subsea chokes shall be designed for the temperature ratings specified in 5.1.2.3. For subsea chokes, the maximum temperature rating is based on the highest temperature of the fluid that can flow through the choke. Subsea chokes shall have a maximum temperature rating equal to or greater than the tree. The minimum temperature rating of subsea chokes shall be in accordance with the manufacturer's written specifications but equal to or less than the tree rating.~~

~~End Connections~~

~~End connections for chokes shall be as specified in 7.1 to 7.6.~~

~~Vent Requirements~~

~~Subsea chokes shall be designed to prevent internal cavities from trapping pressure. The system shall have the means to facilitate pressure being vented prior to releasing and during landing of the body to bonnet connector.~~

~~External Pressure Requirements~~

~~Subsea chokes shall be designed to withstand external pressure at the maximum rated water depth. The design shall prevent the ingress of water from external pressure.~~

~~Factory Acceptance Test~~

~~Hydrostatic testing of subsea chokes shall be in accordance with 5.4. If functional testing is performed, reference Tables 24 and 26 for example data sheets.~~

~~Subsea Choke Actuators/Operators~~

~~General~~

~~Subsea choke actuators/operators shall be a fail-in-place design in accordance with requirements in 7.10.2.2 and the following.~~

~~Actuator manufacturer shall document design and operating parameters, as listed in 7.20.3.2 and 7.20.3.3.~~

~~Motion type (ratchet, stepping, linear, rotary, etc.) of actuator/operator shall be described and documented, including the number of turns, steps, or partial movement graduation between full-closed and full-open positions.~~

~~Rotary-operated subsea choke actuators/operators shall be turned in the counter-clockwise direction to open and clockwise to close the choke as viewed from the end of the stem.~~

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~~The actuator/operator mechanism shall be designed to prevent backdriving by the choke under all operating conditions, including loss of power or communication to the actuator/operator.~~

~~Since chokes are fail-in-place devices, the closing/opening force requirement from 7.10.2.2.4 does not apply.~~

Table 24—Example Documentation of the Factory Acceptance Testing for a Subsea Choke with Actuator/Operator—Mechanical Override Operational Test

Factory Acceptance Test Form for a Subsea Choke with an Actuator/Operator with Mechanical Override Operational Test (Choke with Manual Operator and Choke Hydraulic Operator with Manual Override)								
Test No.	Cycle No.	Choke Pressure	Verification That the Choke Operates without Backdriving					
			During Opening			During Closing		
			Time	Starting Torque	Running Torque	Time	Starting Torque	Running Torque
1	1	Atmospheric pressure						
	2	Atmospheric pressure						
	3	Atmospheric pressure						
2	1	Working pressure						
	2	Working pressure						
	3	Working pressure						
	4	Working pressure						
	5	Working pressure						

Design and Operating Parameters of Manual Operator for Subsea Chokes

The following parameters shall be documented:

operating torque input;

maximum rated torque capacity;

type and size of interface (ROV) for manual operation;

material class;

temperature rating;

number of turns, steps, or partial movement graduation between full closed and full open positions.

Design and Operating Parameters of Actuators for Subsea Chokes

The following parameters shall be documented:

design type (ratchet, stepping, rotary, linear actuators);

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~~maximum output torque capacity;~~

~~material class;~~

~~temperature rating;~~

~~full stroke definition;~~

~~hydraulic fluid compatibility for hydraulic actuators;~~

~~hydraulic cylinder(s) (if provided);~~

~~number of cylinders;~~

~~volume;~~

~~pressure rating: maximum hydraulic operating pressure and minimum hydraulic operating pressure;~~

~~maximum actuator operation speed;~~

~~type of local position indicator (if any);~~

~~manual override (if supplied);~~

~~ROV assist or diver assist;~~

~~maximum input torque capacity;~~

~~operation;~~

~~maximum;~~

~~type and size of interface (ROV) for manual operation hex;~~

~~number of turns to open or close the choke;~~

~~water depth rating;~~

~~type of volume compensation device (if any);~~

~~bladder;~~

~~piston.~~

~~Documentation~~

~~The actuator manufacturer shall provide installation and service manuals.~~

~~Actuator/Operator Testing~~

~~Subsea choke actuators/operators shall conform to the testing requirement of 7.10.4.2.3. All test data shall be recorded on a data sheet such as listed in Table 24, Table 25, and/or Table 26.~~

~~When subsea choke actuators are shipped separately, the actuators shall be assembled with a test fixture that meets the specified choke operating parameters and tested as specified in 7.20.4~~

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~~NOTE—Table 25 offers an example of test documentation.~~

~~Table 25—Example Data Sheet for the Factory Acceptance Testing of a Hydraulic Actuator~~

A: Actuator Data	
Manufacturer	
Model no.	
Serial no.	
Part no.	
Size	
PSL	
Hydraulic pressure rating	
Temperature rating	
Actuator separate or with choke	
B: Actuator Cylinder Seal Test (Hydrostatic Test)	
Test pressure	
Cylinder 1	
Holding period	Beginning
	Completion
	Total test time
Cylinder 2	
Holding period	Beginning
	Completion
	Total test time

Performed by	
Date	
C: Performance Test for Actuators Shipped Separately	
See Table 26:	

Choke and Actuator/Operator Assembly Factory Acceptance Test

Subsea choke and actuator/operator assembly shall be tested together to demonstrate proper assembly and operation. This shall be accomplished by actuating the subsea choke from the fully closed position to the fully open position a minimum of three times with the choke body at atmospheric pressure and a minimum of five times with the choke body at RWP. All test data shall be recorded on a data sheet, including:

pressure inside choke body;

actuator pressure or power required to close choke;

actuator pressure or power required to open choke;

verification that the choke operates without backdriving within the manufacturer's specified torque limit.

NOTE Table 27 offers an example of test documentation.

Table 26—Example Documentation of the Factory Acceptance Testing for the Operational Test of a Subsea Choke with Actuator/Operator

Factory Acceptance Test Form for the Operational Test of a Subsea Choke with						
Test No.	Cycle No.	Choke Pressure	Hydraulic Pressure or Electric Power Required to		Verification That the Choke Operates without Backdriving	
			Close Choke	Open Choke	During Opening	During Closing
					Time	Time
4	1	Atmospheric				
	2	Atmospheric				
	3	Atmospheric				
2	4	Working pressure				

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	2	Working pressure				
	3	Working pressure				
	4	Working pressure				
	5	Working pressure				

Table 27—Example Data Sheet for the Factory Acceptance Testing of a Manual Operated Subsea Choke

A: Choke Data	
Manufacturer	
Model no.	
Part no.	
Serial no.	
Orifice size	
Working pressure	
Test pressure	
Temperature rating	
PSL	
B: Hydrostatic Test	
Test pressure	
First holding period	Beginning
	Completion
	Total test time
Second holding period	Beginning

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	Completion
	Total test time
Performed by	
Date	
C: Operational Test of Subsea Choke with Manual Operator	
Test 1	Pressure in choke
1	
2	
3	
Test 2	Pressure in choke
1	
2	
3	
4	
5	
Performed by	
Date	

Insert Retrievable Choke

General

Insert retrievable chokes shall have a visual marking system indicating full make-up and full release position of the insert to body connector system.

Connector

Connector system shall be designed to be self-locking in the locked clamped position to prevent backdriving in service under all operational loads.

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~~Connection mechanism of an insert retrievable choke shall have a secondary release feature or diver/ROV access for cutting/removal of the mechanism. Placement and connection mechanism of an insert retrievable choke locking mechanism (to the rest of the choke assembly) should allow for adequate access for diver/ROV operations.~~

~~A rotary connector drive shall be turned in the counterclockwise direction to open the connector and the clockwise direction to close as viewed from the end of the stem.~~

Seal System

~~It shall be possible to test the insert to the body seat seal to validate seal function.~~

~~A blanking trim may be used when performing this test.~~

Design and Operating Parameters of Connectors for Subsea Chokes

The following parameters shall be specified:

~~clamp make-up torque or linear thrust rating;~~

~~clamp maximum input torque or maximum linear thrust rating;~~

~~type and size of interface (ROV);~~

~~number of turns to open or close, or linear travel, to operate the clamp.~~

Materials

~~Both subsea chokes and subsea actuators/operators shall be made of materials that meet the applicable requirements of 5.2 and the requirements of API 6A.~~

Welding

~~Welding of pressure-containing components shall be performed in accordance with the requirements given in 5.3. Welding of pressure-controlling ("trim") components shall conform to the manufacturer's written specifications.~~

Marking

~~Marking of subsea chokes, actuators/operators, and choke/actuator assemblies shall be marked as given in Table 28, Table 29, Table 30, and Table 31.~~

Table 28—Marking for Subsea Chokes

Marking		Application
1	Manufacturer's name or trademark	Nameplate
2	API 17D	Nameplate
3	Manufacturer's part number	Nameplate
4	PSL designation	Nameplate
5	RWP	Nameplate
6	Temperature rating	Nameplate

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7	Material class (including maximum H ₂ S partial pressure, if applicable)	Nameplate
8	Unique identifier (serial number, PSL 3 and above)	Nameplate

Table 29—Marking for Subsea Choke Manual Operators

Marking		Application
1	Manufacturer's name or trademark	Nameplate
2	API 17D	Nameplate
3	Manufacturer's part number	Nameplate
4	Unique identifier (serial number, PSL 3 and above)	Nameplate

Table 30—Marking for Subsea Choke Actuator/Operator

Marking		Application
1	Manufacturer's name or trademark	Nameplate
2	API 17D	Nameplate
3	Hydraulic cylinder maximum working pressure Hydraulic actuator	Nameplate and hydraulic actuator cylinder or
4	Manufacturer's part number	Nameplate
5	Unique identifier (serial number, PSL 3 and above)	Nameplate and actuator cylinder or power unit housing
6	Number of steps from close to full open (if applicable)	Nameplate

Table 31—Marking for Subsea Choke and Actuator/Operator Assembly

Marking		Application
1	Assembler's name or trademark	Nameplate
2	API 17D	Nameplate
3	Assembly serial or identification number	Nameplate
4	Maximum water dept rating	Nameplate
5	Manual override direction to open—CW or CCW	Nameplate

Miscellaneous Equipment

Design

General Design Requirements

Design Load/Conditions

As a minimum, the following loads shall, where applicable, be included when designing miscellaneous equipment:

suspended weight;

~~control pressure;~~

~~well pressure;~~

~~hydrostatic pressure;~~

~~handling loads;~~

~~impact.~~

Operating Pressure

~~Tools operated by hydraulic pressure shall be rated in accordance with the pressure ratings specified by the manufacturer.~~

Remote Guideline Establishment and Re-establishment Tools

~~NOTE—Guideline establishment/re-establishment tools are used to attach cables to guideposts of subsea completion structures.~~

~~Any guideline establishment/re-establishment tool that uses the relative guidepost positions shall be designed based on the spacing described in 8.3.2.2.~~

Test Stands and Fixtures

General

~~Miscellaneous equipment shall be designed and manufactured in accordance with the structural requirements, stress limitations, and documentation requirements of 5.1.~~

~~NOTE—Test stands and fixtures (including jigs) are used at the point of assembly or installation to validate the interface and functional operation, load and pressure capacity, and interchangeability of the equipment being installed. They can also serve as the shipping skids for transporting equipment offshore. Test stands and fixtures used only at the manufacturer's facilities are outside the scope of this specification.~~

Accuracy of Test Equipment

~~Where test equipment is used to simulate a mating component for testing the assembly of interest, it shall be made to the same dimensions, tolerances, and surface finish at all interfaces as the simulated component.~~

Loads During Testing/Handling and Assembly

~~Design of test stands and fixtures shall include assembly and handling loads as well as test loads.~~

Test Stumps

~~Test stumps simulate the profiles of the wellhead, tree re-entry interface, etc., to facilitate pressure testing of the tree, tree running tool, tree cap, etc., and to position orienting joints relative to the BOP stack. They may also contain hydraulic couplers to facilitate testing of the control functions. Stab pockets may be machined directly in the stump or, for tree testing, may be contained in a dummy tubing hanger.~~

~~When specified, the tree test stump shall accept a real tubing hanger. Test ports shall communicate with the individual bores of the test stumps to facilitate pressure testing. Guidance provided by the test stumps shall simulate the requirements of the actual equipment being tested.~~

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Equipment Used for Shipping

~~Test skids, etc. used for shipping equipment offshore shall provide protection to the equipment during handling and transportation.~~

~~Sea fastenings shall be designed for all static and accelerated loading conditions due to roll, pitch, and heave of the vessel in the locality where it will be transported and should be suitable for securing the assembly to the rig and rig skids (see 5.5.2).~~

Materials

~~Materials shall conform to 5.1 and 5.2 for all pressure-containing and high load-bearing parts, if subjected to well fluid contact. Selection of other materials shall include the effects of encountered fluids and galvanic compatibility, as well as mechanical properties. Seal surfaces that engage metal-to-metal seals shall be inlaid with a CRM that is compatible with the well fluids, seawater, etc. Overlays are not required if the base material is compatible with well fluids, seawater, etc.~~

Testing

~~All components subject to pressure shall be tested to one and one-half times their RWP unless a different test pressure is required elsewhere in this specification. The test procedure shall conform to 5.4. Testing shall be performed in accordance with the manufacturer's written specification to confirm fit and function for any tool that has an interface with equipment that is being installed subsea.~~

Marking

~~Marking shall be in accordance with 5.5.1.~~

Specific Requirements—Subsea Wellhead

General

~~NOTE 1—Section 8 describes subsea wellhead systems that are normally run from floating drilling rigs. It establishes standards and specifications for this equipment. The subsea wellhead system supports and seals casing strings. It also supports the BOP stack during drilling, and the subsea tree and possibly the tubing hanger after completion. The subsea wellhead system is installed at or near the mudline.~~

~~All pressure-containing and pressure-controlling parts included as part of the subsea wellhead equipment shall be designed to meet all the requirements of NACE MR0175 (all parts). These parts shall include:~~

~~wellhead (high-pressure) housing;~~

~~production casing hanger body;~~

~~annulus seal and seal bodies;~~

~~sealing casing hanger lockdown bushing body.~~

~~The requirements of NACE MR0175 (all parts) shall not be mandatory for the following components:~~

~~casing hanger bodies for other than production casing;~~

~~the conductor (low-pressure) housing body;~~

~~lock rings;~~

~~load rings;~~

~~load shoulders;~~

~~submudline equipment;~~

~~bore protectors and wear bushings;~~

~~nonsealing lockdown bushing body.~~

~~Additionally, life-of-well parameters shall be included in the design, including contributions from the drilling, testing, completion, and production phases of well operations.~~

~~Further evaluation shall be required for the following issues, that affect long-term reliability:~~

~~cyclic external loads;~~

~~internal pressure cycle loads and displacements;~~

~~thermal loads and gradients;~~

~~general corrosion;~~

~~stress corrosion cracking (due to hydrogen, H₂S or chlorides).~~

~~NOTE 2 — While the codes governing the structural capacity of the wellhead system ensure reliability in the short term, this is insufficient to ensure integrity for long-term production applications.~~

~~These issues may require assessment by fatigue analysis, fracture mechanics evaluation, structural evaluation due to thermal loading, or structural evaluation with reduced capacity due to corrosion allowance. While cathodic protection systems are often used for production wells to reduce corrosion, this can increase the possibility for stress corrosion cracking due to the release of free hydrogen.~~

~~Temporary Guidebase~~

~~General~~

~~The temporary guidebase (TGB) when used provides a guide template for drilling the conductor hole and stabbing the conductor pipe. It compensates for misalignment from irregular ocean-bottom conditions and may provide a support base for the PGB. If used together with a PGB, a cone-and-gimbal arrangement compensates for angular misalignment between the TGB and the PGB due to the seabed topography and the verticality of the well. For guideline systems, it also establishes the initial anchor point for the guidelines. It may also include a provision for suspending a foundation sleeve to support unconsolidated surface soils. The TGB might not always be used, as in the case of template completions or satellite structure (foundation and/or protective structure) completions.~~

~~A TGB may also serve as a mudmat if the drilling of the conductor hole is performed by jetting operations. In this instance, it serves a physical stop to ensure that the wellhead stays a fixed distance above the sea floor and subsequently serves as a temporary foundation, enhancing the bearing load capacity in unconsolidated or under-consolidated surface soils. The increased bearing capacity is used to support the weight of the conductor (preventing it from sinking) until the next section of hole is drilled and the surface pipe is sufficiently landed and cemented in place.~~

~~Provisions for the design shall conform to the requirements in 5.1.3.6.~~

Design

Design Load/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

ballast;

guideline tension;

weight of conductor pipe;

weight of PGB assembly;

hanging or suspension loads;

soil reaction.

The TGB shall be capable of supporting, as a minimum, a static load of 175,000 lbf (780 kN) on the interface with the PGB while the TGB is supported at four locations, equally spaced $90^\circ \pm 2^\circ$ apart and a minimum of 62 in. (1575 mm) from the center (radial measure).

NOTE—Recommendations for lifting pad eyes are outlined in Annex G.

Dimensions

The requirements for dimensions shall be as follows.

The TGB minimum bearing area shall be 75 ft² (7 m²). This area may be augmented with weld-on or bolt-on extensions to compensate for soil strengths and anticipated loads.

TGB should pass through a 16.4 ft (5 m) square opening or as specified by the manufacturer.

TGB shall provide four guideline anchor points in position to match the guideposts on the PGB.

Together with the PGB, the TGB shall allow a minimum angular misalignment of 5° between the conductor pipe and the TGB.

TGB shall provide a minimum storage volume of 70.6 ft³ (2 m³) for ballast material.

Permanent Guidebase

General

The PGB attaches to the conductor (low-pressure) housing and provides guidance for the subsea drilling and completion equipment (surface casing, BOP, production tree, running tools). The PGB provides entry into the well prior to installation of the wellhead (high-pressure) housing and BOP. After the wellhead (high-pressure) housing installation, the PGB provides guidance of the BOP, subsea tree, or tubing head onto the wellhead (high-pressure) housing using guideline or guidelineless methods. It may establish structural support and final alignment for the wellhead system and provides a seat and lockdown for the conductor (low-pressure) housing. PGBs can be built as a single piece or split into two pieces to ease handling and installation. Optionally, they may include provisions for conductor pipe hang-off, retrieval and to transfer flowline loads. The PGB may be retrieved after drilling is complete and replaced by a PGB

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~~carrying flowline connection/manifold equipment. Alternatively, the PGB installed for drilling may carry flowline connection/manifold equipment.~~

~~The PGB shall not interfere with the BOP stack installation. ROV access and cuttings disposal shall be included in the design.~~

~~A PGB using a re-entry funnel for guidelineless equipment guidance is often referred to as a "guidelineless re-entry assembly" or GRA. The re-entry funnel may be on the GRA housing looking upward (funnel up) or may be configured in concert with matching funnel equipment on the subsea equipment subsequently landed in the GRA (funnel down). Funnel geometry usually involves one (or more) cone(s) and a center cylinder frame to provide alignment between mating components/structures.~~

~~The outermost diameter of the cone should be no less than 1.5 times the diameter of the component it is capturing. The cone's angle should be no shallower than 40° with respect to horizontal. Typically, the cone angle is 45°. Once captured, the GRA's cone(s) and inner cylinder should be designed to allow for equipment re-entry at tilt angles up to 3° from vertical in any orientation, and subsequently assist in righting the captured component to vertical.~~

~~Portions of the re-entry cone may be scalloped out to accommodate the guidelineless re-entry of adjacent equipment whose capture funnel can intersect with the main funnel(s) because of space constraints. This is acceptable, although it takes away from the re-entry properties of the funnel in the scalloped-out area.~~

~~Its practice should be carried out with sound engineering judgement comparing operational limits lost vs. size and weight gained. Ideally, scalloped funnels should be minimized or covered wherever practical.~~

~~GRAs also may include provisions for conductor-pipe hang-off.~~

~~If so, since GRAs are typically cylindrical and conical in nature, horizontal resting pads or a beam structure should be incorporated in the frame's design to provide a sound flat surface that can firmly sit on spider beams.~~

~~When spatial orientation is required, the funnel up funnels and capture equipment may also feature Y-slots and orienting pins.~~

~~The upper portion of the Y-slot should be wide enough to capture mating pins within $\pm 7.5^\circ$ of true orientation. The Y-slot should then taper down to a width commensurate with the pin to provide orientation to within $\pm 0.5^\circ$ (similar to the angular orientation provided by guideposts and funnels).~~

~~Typically, there are two or four orienting pins, each with a minimum diameter of 4.00 in. (101.6 mm) in diameter. Other orientation methods, such as orienting helixes or indexing devices (ratchets, etc.) may be used. Whatever the orienting method, it is necessary that the design allow for the 3° tilt re-entry requirement with enough play to accommodate this gimballing effect.~~

~~Funnel down funnels do not easily accommodate Y-slots and orienting pins. Alternate orientation methods such as orientation helixes or indexing devices may be required.~~

~~PGB/GRAs should not impede the flowby required for cementing, jetting operations, etc.~~

~~Provisions for design shall conform to the requirements in 5.1.3.6.~~

Design

Design Load/Conditions

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~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply (see Figure 12 and Figure 13):~~

~~conductor pipe weight;~~

~~conductor (low-pressure) housing weight;~~

~~hanging loads;~~

~~jetting string weight when supported on the spider beams;~~

~~guideline tension;~~

~~flowline pull-in, connection, or installation loads;~~

~~annulus access connection loads;~~

~~environmental;~~

~~reaction for TGB;~~

~~installation loads (including conductor hang-off on spider beams);~~

~~snagging loads;~~

~~BOP loads;~~

~~sea fastening (when supported on spider beams).~~

~~The PGB or GRA shall be capable of supporting, as a minimum, a static load of 175,000 lbf (780 kN) on the interface with the conductor (low-pressure) housing, whereas the PGB is supported at four locations equally spaced $90^\circ \pm 2^\circ$ apart and a minimum of 60 in. (1525 mm) from the center (radial measure).~~

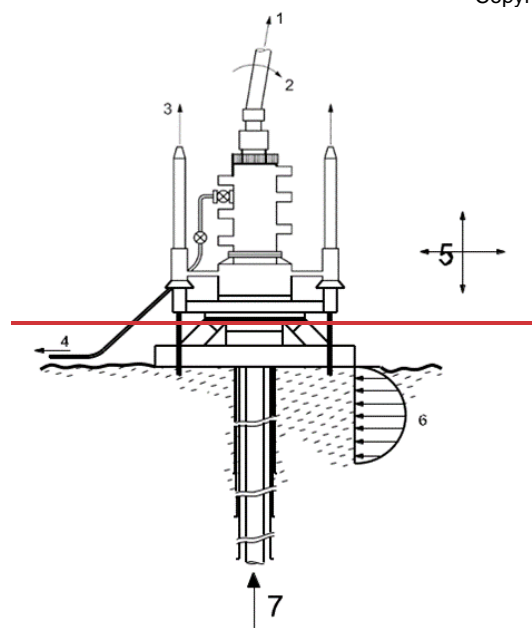
~~PGB Dimensions~~

~~The PGB dimensional requirements shall be as follows.~~

~~The dimensions of the PGB shall conform to the dimensions shown in Figure 10 a).~~

~~The guideposts shall be fabricated of $8\frac{5}{8}$ in. (219 mm) OD pipe or tubulars. Guidepost funnels are typically fabricated from $10\frac{3}{4}$ in. OD \times 0.5 in. wall (273 mm OD \times 13 mm wall) pipe or tubulars.~~

~~The length of the guidepost [item 1 in Figure 10 a)] shall be 8 ft (2440 mm) minimum for drilling purposes. The guideposts may be extended to provide guidance for the subsea tree, LWRP, and/or tree cap.~~



Key

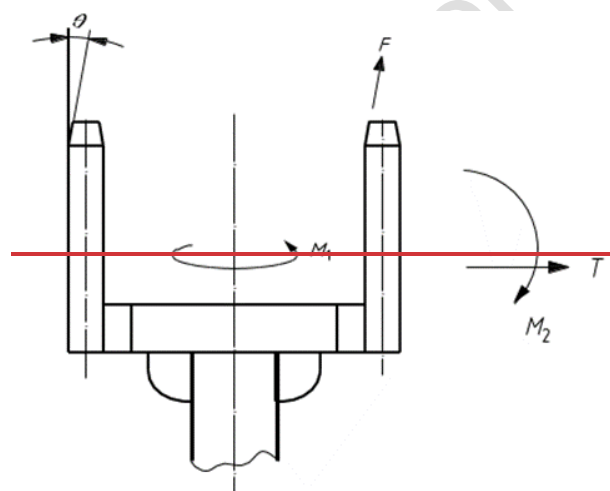
riser tension — 5 — environmental (current, wave, action, etc.)

applied moments — 6 — soil reaction

guideline tension — 7 — thermal

flowline connection

Figure 12—External Loads on a Subsea Tree and Wellhead



Key

F — force from guideline

M_1 — torsional bending moment

M_2 — bending moment

T — tension

θ — angle at which guideline force acts

Figure 13—Permanent Guidebase Loads

GRA Dimensions

~~NOTE—The re-entry funnel may be on the GRA housing looking upward (funnel-up) or may be configured in concert with matching funnel equipment on the subsea equipment subsequently landed in the GRA (funnel down). Funnel geometry usually involves one (or more) cone(s) and a center cylinder frame to provide alignment between mating components/structures.~~

~~The outermost diameter of the cone should be no less than 1.5 times the diameter of the component it is capturing. The cone's angle should be no shallower than 40° with respect to horizontal. Typically, the cone angle is 45°. Once captured, the GRAs cone(s) and inner cylinder should be designed to allow for equipment re-entry at tilt angles up to 3° from vertical in any orientation, and subsequently assist in righting the captured component to vertical.~~

~~When spatial orientation is required, 7.14.2.1 shall apply.~~

Functional Requirements

~~The functional requirements shall be as follows:~~

~~When used with the TGB, the PGB (GRA) shall allow a minimum angular misalignment of 5° between conductor pipe and the TGB. For other conductor pipe sizes, the manufacturer shall document the misalignment capability.~~

~~Guideposts shall be field-replaceable without welding, using either diver, ROV, or remote tooling. The locking mechanism should not inadvertently release due to snagging wires, cables, etc.~~

~~Guideposts can be either slotted or non-slotted. Slotted guideposts are required when used with a TGB, if the guidelines are not disconnected from the TGB. For slotted guideposts, provisions shall be made to insert guidelines of at least $\frac{3}{4}$ in. (19 mm) OD into the post with retainers at the top and at or near the bottom of the post.~~

~~Provisions shall be made to attach guidelines to the top of the guideposts. The guidelines shall be capable of being released and re-established.~~

~~NOTE 1—This may occur using diver, ROV, or remote tooling.~~

~~The PGB (GRA) should contain a feature that facilitates the orientation between the PGB (GRA) and the conductor (low-pressure) housing.~~

~~NOTE 2—The orientation device may allow the installation of the guidebase in multiple orientation positions to suit rig heading or installed equipment orientation. The orientation device may also provide an antirotation feature to resist the loads defined in 8.3.2.1.~~

~~When specified, the PGB (GRA) shall contain grouting funnels for cement top-up.~~

~~When specified, the PGB (GRA) shall contain seals and a structure to deflect seabed and cement-port gases (which can form hydrates) from entering the BOP, subsea tree, or tubing head connector.~~

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~~Guidelineless equipment shall not reduce the release angle of the BOP, tree, or tubing head connector. The guidelineless equipment shall allow installation and retrieval of equipment up to a 3° angle without damaging the wellhead seal surfaces or contacting installed wellhead gaskets.~~

~~A positive lock or load shoulder should be used to hang off the conductor in the PGB (GRA).~~

~~Dedicated lift points shall be provided.~~

~~PGB (GRA) should not impede flowby.~~

~~PGB (GRA) shall be designed to be run with a conductor (low-pressure) housing or independently on a running tool.~~

~~Conductor (Low-pressure) Housing~~

~~General~~

~~NOTE 1 — The conductor (low-pressure) housing attaches to the top of the conductor pipe to form the foundation of a subsea well. The housing typically has a means of attaching to the PGB (GRA), which can also provide a means for antirotation between the PGB (GRA) and the conductor (low-pressure) housing.~~

~~NOTE 2 — A typical conductor (low-pressure) housing profile is shown in Figure 14. The internal profile of the conductor (low-pressure) housing includes a landing shoulder suitable for supporting the wellhead (high-pressure) housing and the loads imposed during the drilling, completion, and workover operations.~~

~~Running tool preparations should also be a part of the internal housing profile. The external profile of the conductor (low-pressure) housing shall be compatible with supporting the conductor pipe in the rotary table and/or at the spider beams in the moonpool. Cement return passageways may be incorporated in the conductor (low-pressure) housing/PGB (GRA) assembly to allow directing cement and mud returns either below the PGB (GRA) or through ports in the PGB (GRA).~~

~~NOTE 3 — Provision for seals against hydrates, etc., may also be incorporated in the conductor (low-pressure) housing when required.~~

~~NOTE 4 — Other enhancements to the conductor (low-pressure) housing, such as cuttings disposal, cement top-off, rigid lockdown, etc., may be included. An intermediate casing string may also be hung off inside the conductor (low-pressure) housing prior to the wellhead casing string. Facilities for landing the intermediate casing string can be required for the wellhead casing string. Methods of annular shut-off may be used on flowby holes to avoid hydrate migration from the annulus between the conductor pipe and the wellhead casing string.~~

~~Design~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply (see 8.2.2.1):~~

~~wellhead loads;~~

~~hanging/hang-off loads while suspended in the moonpool;~~

~~riser forces;~~

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PGB loads (see Figure 12 and Figure 13);

environmental loads;

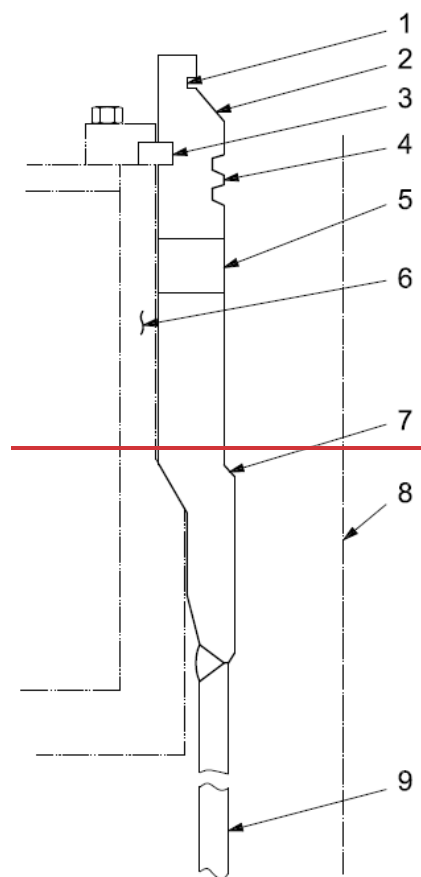
snag loads;

pressure loads;

thermal loads;

fatigue assessment.

The interface between the conductor (low-pressure) housing and the PGB shall be designed for a minimum rated load of 175,000 lbf (780 kN).



Key

wellhead lockdown — 6 — PGB

landing shoulder for wellhead — 7 — landing shoulder

PGB attachment — 8 — centerline

running tool and tieback connector preparation — 9 — conductor casing

cement port (optional)

Figure 14—Typical Conductor (Low-pressure) Housing

Bottom Connection

~~The bottom connection shall conform to the purchasing requirement for connection type and casing loads.~~

~~The manufacturer shall address the design and use of weldments, extensions, reducers, swages, etc. to the manufacturer's written specification to meet the casing ends and load requirements.~~

~~Weld end connections shall be prepared for a full penetration butt weld.~~

~~The manufacturer shall document the alignment between the mated parts of a welded joint.~~

~~The manufacturer and user/purchaser should agree on bottom connection requirements with respect to fatigue criteria.~~

Pup Joint

~~NOTE—The bottom end connection may feature a pup joint of casing that is factory installed to ease field installation. In addition, handling and support lugs may be added for hang-off during field installation or for handling during shipping.~~

~~The maximum rotary table hang-off height for joint make-up should be specified by the user/purchaser.~~

~~Sufficient length for tongs on the body and pup joint should be provided for threaded torque make-up.~~

~~The user/purchaser and manufacturer shall agree on the pup joint's design specification and length, with end connection(s) conforming to 8.4.2.3. Support lug design shall be in accordance with 5.1.3.6, 5.1.3.7, 5.4.4, and 5.5.2.~~

Testing

Validation

~~Conductor (low-pressure) housings shall conform to the manufacturer's written specification.~~

Factory Acceptance Testing

~~A dimensional check or drift test shall be performed on the conductor (low-pressure) housing to confirm the manufacturer's written specification.~~

Wellhead (High-pressure) Housing

General

~~NOTE 1—The wellhead (high-pressure) housing lands inside the conductor (low-pressure) housing. It provides pressure integrity for the well, suspends the surface and subsequent casing strings and tubing hanger, and resists against external loads. The BOP stack or subsea tree attaches and seals to the top of the wellhead (high-pressure) housing using a compatible wellhead connector and gasket.~~

~~The wellhead (high-pressure) housing shall accept tubing hangers or tubing hanger adapter.~~

~~Body penetrations within the housing pressure boundary shall not be permitted.~~

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~~NOTE 2 — The standard system sizes are given in Table 17. Figure 15 shows profiles of two typical wellhead (high-pressure) housings.~~

~~Design~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

~~riser forces (drilling, production, and workover);~~

~~BOP loads;~~

~~subsea tree loads;~~

~~pressure (internal and external);~~

~~radial loads;~~

~~thermal loads;~~

~~environmental loads;~~

~~flowline loads;~~

~~suspended casing loads;~~

~~conductor housing reactions;~~

~~tubing hanger reactions;~~

~~hydraulic connector loads;~~

~~fatigue assessment.~~

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Key

~~landing shoulder 9 — minimum bore~~

running tool preparation — 11 — wellhead (high-pressure) housing pressure boundary

~~annulus seal assembly area~~ ~~12~~ ~~position of lowermost annulus seal assembly or test tool seal~~

Connections

~~The top connection should be of a hub or mandrel type (see Figure 15) as specified by the user/purchaser. The gasket profiles shall be manufactured from or inlaid with CRM as specified in 5.3.3. The gasket profile shall provide a primary and a secondary gasket seal area.~~

~~Bottom Connection~~

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~~The bottom connection shall conform to the purchasing requirements for connection type and casing loads.~~

~~The manufacturer shall address the design and use of weldments, extensions, reducers, swages, etc. to the manufacturer's written specification to meet the casing ends and load requirements.~~

~~Weld end connections shall be prepared for a full-penetration butt weld.~~

~~The manufacturer shall document the alignment between the machined part and welded joint.~~

~~The manufacturer and the user/purchaser should agree on bottom connection requirements with respect to fatigue criteria.~~

Pup Joint

~~NOTE—The bottom end connection may feature a pup joint of casing that is factory installed to ease field installation.~~

~~The maximum rotary table hang-off height for joint make-up should be specified by the user/purchaser.~~

~~Enough length for tongs on the body and pup joint should be provided for threaded torque make-up.~~

~~The user/purchaser and manufacturer shall agree on the pup joint's design specification and length, with end connections conforming to this section.~~

Dimensions

~~The dimensional requirements shall be as follows.~~

~~The minimum vertical bore of the wellhead (high-pressure) housing shall be as given in Table 17.~~

~~Dimensions of the wellhead pressure boundary (see Figure 15) shall be in accordance with the manufacturer's written specification.~~

Rated Working Pressure

~~The RWP for the wellhead (high-pressure) housing pressure boundary (see Figure 15) shall be 5000 psi (34.5 MPa), 10,000 psi (69 MPa), or 15,000 psi (103.5 MPa).~~

Factory Acceptance Testing

~~All wellhead (high-pressure) housings shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic test is performed to confirm the pressure integrity of the housing pressure boundary. All wellhead (high-pressure) housings shall be tested to the requirements of PSL 3.~~

~~The hydrostatic body test pressure shall be determined from the housing RWP (see Table 32). The hydrostatic body test pressure shall not be less than the values given in Table 32.~~

~~Wellhead (high-pressure) housings shall show no visible leakage during each pressure holding period. Any permanent deformation of the housing, after hydrostatic testing is complete, shall not adversely affect the function of the casing hangers, packoffs, gaskets, connectors, or other subsea equipment.~~

Table 32—Test Pressure

Rated Working Pressure	Hydrostatic Body Test Pressure
-------------------------------	---------------------------------------

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psi	(MPa)	psi	(MPa)
5000	(34.5)	7500	(51.8)
10,000	(69.0)	15,000	(103.5)
15,000	(103.5)	22,500	(155.2)

Marking

Marking shall be in accordance with 5.5.1, including the following additional marking information:

PSL;

RWP;

temperature rating;

material class.

Casing Hangers

General

Pressure

~~Subsea casing hangers shall be treated as pressure-controlling equipment.~~

~~Submudline casing hangers suspended from submudline landing rings shall meet the requirements of 8.14.~~

~~NOTE 1 — The subsea casing hanger is installed on top of each casing string and supports the string when landed in the wellhead (high-pressure) housing. It is configured to run through the drilling riser and subsea BOP stack, land in the subsea wellhead, and support the required casing load.~~

~~Casing hangers shall have provisions for an annulus seal assembly and support loads generated by BOP test pressures above the hanger and loads due to subsequent casing strings. Means shall be provided to transfer casing load and test pressure load to the wellhead (high-pressure) housing or to the previous casing hanger. If required, a lockdown mechanism shall be used to limit or restrict movement of the casing hanger.~~

~~NOTE 2 — The lockdown mechanism can be integral to the annulus seal assembly or run as part of an independent assembly.~~

Bottom Connection

~~A pup joint of casing should be installed on the hanger. This reduces the risk of damage during handling and later make-up in the field. API threaded connections should follow API 5CT for make-up requirements when connecting the pup joint to the hanger.~~

~~Proprietary thread connection should be made up in accordance with the manufacturer's written specification.~~

Design

Design Load/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

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~~The following may apply (including lockdown mechanisms, if used):~~

~~casing loads;~~

~~overpull;~~

~~pressure, internal and external;~~

~~thermal;~~

~~torsional;~~

~~radial;~~

~~impact.~~

~~Threaded Connections~~

~~The type of casing threads on the hanger shall be specified by the user/purchaser. Identification markings shall conform to API 6A.~~

~~**Table 33—Recommended Minimum Vertical Bore Sizes for Casing Hangers, Bore Protectors, and Wear Bushings**~~

Nominal Casing OD	Minimum Vertical Bore	
in.	in.	(mm)
7	6.03	(153)
7⁵/₈	6.78	(172)
8⁵/₈	7.66	(195)
9⁵/₈	8.53	(217)
9⁷/₈	8.53	(217)
10³/₄	9.53	(242)
11³/₄	10.66	(271)
13³/₈	12.28	(312)
13⁵/₈	12.28	(312)
14	12.28	(312)

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16	14.81	(376)
18	16.55	(420)
20	17.58	(447)

~~Casing threads should be coated to prevent galling when required by the thread type or material and should be specified by the manufacturer.~~

Minimum Vertical Bore for Full-opening Casing Hangers

~~The minimum vertical bores for full-opening or full-bore casing hangers should be as given in Table 33.~~

~~Equipment conforming to this requirement shall be referred to as having full-opening bores. Reduced vertical bores may also be supplied.~~

Casing Hanger Ratings

~~NOTE—The load and pressure ratings for casing hangers can be a function of the tubular grade of material and wall section as well as the wellhead equipment in which it is installed.~~

~~The user/purchaser shall be responsible for selecting the weight, grade, and thread of casing.~~

~~The manufacturer shall address the following load/pressure ratings for casing hangers, as defined below, based on the user/purchaser's requirements.~~

~~Hanging capacity—The manufacturer's stated hanging capacity rating for a casing hanger includes the casing thread (normally a female thread) cut into the hanger body.~~

~~Pressure rating—The manufacturer's stated pressure rating for a casing hanger includes the hanger body and the casing thread (normally a female thread) cut into the lower end of the hanger.~~

~~BOP test pressure—The BOP test pressure rating for a casing hanger is the maximum pressure that may be applied to the upper portion of the hanger body and to the annulus seal assembly. This rating specifically excludes the casing connection at the lower end of the casing hanger.~~

~~Support capacity—The manufacturer's stated support capacity is the rated weight that the casing hanger(s) are capable of transferring to the wellhead (high-pressure) housing or previous casing hanger(s). The effects of full rated internal working pressure shall be included.~~

Flowby Area

~~An external flowby area allows for returns to flow past the hanger during cementing operations and is designed to minimize pressure drop while passing as large a particle size as possible. Casing hanger minimum flowby areas and maximum particle size shall be documented by the manufacturer and maintained for each casing hanger assembly.~~

Testing

Validation

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~~Subsea wellhead casing hangers shall conform to 5.1.7 and be compliant with API 6A mandrel hanger group definitions. Testing for internal pressure shall be performed to validate the structural integrity of the hanger and shall be independent of the casing grade and thread.~~

~~Factory Acceptance Testing~~

~~A dimensional check or drift test shall be performed on the hanger to confirm the minimum vertical bore (see Table 33) conforms to the manufacturer's specification.~~

~~FAT of subsea wellhead casing hangers does not require pressure testing.~~

~~Marking~~

~~Marking shall be in accordance with 5.5.1, including the following additional marking information:~~

~~PSL;~~

~~RWP, including casing thread;~~

~~temperature rating;~~

~~material class;~~

~~minimum vertical bore;~~

~~casing thread size and type.~~

~~Annulus Seal Assemblies~~

~~General~~

~~Subsea annulus seal assemblies shall be treated as pressure-controlling equipment.~~

~~Design~~

~~Design Load/Conditions~~

~~Design shall meet the requirements of 5.1.3.1.~~

~~The following may apply:~~

~~setting loads;~~

~~thermal loads;~~

~~pressure loads;~~

~~releasing and/or retrieval loads.~~

~~Rated Working Pressure~~

~~The RWP from above for the annulus seal assembly shall be equal to or greater than the RWP of the casing hanger [see 8.6.2.4 b)]. The manufacturer shall specify the RWP from below if it is different than the RWP from above.~~

~~Lockdown~~

~~The annulus seal assembly shall be locked to the casing hanger and/or wellhead (high-pressure) housing.~~

~~The user/purchaser shall define the expected pressure and thermal end loads from casing (expansion) movement and specify whether a locking mechanism to the wellhead (high-pressure) housing is required.~~

~~The manufacturer shall document the operating limits for which the lockdown mechanism is designed.~~

~~The requirement for an additional lockdown device or limiting device during production shall be addressed by the manufacturer based on expected loads (see 8.7.2.1 and 8.8) and annulus seal design.~~

~~Contingency Annulus Seal Assemblies~~

~~Contingency annulus seal assemblies that position the seal in a different area or use a different seal mechanism shall be designed. The design shall meet all requirements given in 8.7.2.~~

~~Testing~~

~~Validation~~

~~Validation of annulus seal assembly and contingency annulus seal assembly shall conform to 5.1.7 and API 6A (group 3 or 4 mandrel hangers).~~

~~Factory Acceptance Testing~~

~~Annulus seal assembly shall be dimensionally inspected per manufacturer specification.~~

~~Casing Hanger Lockdown Bushing~~

~~General~~

~~Lockdown bushings shall be treated as pressure-controlling equipment.~~

~~A casing hanger lockdown bushing may be installed on top of the uppermost casing hanger in the subsea wellhead (high-pressure) housing to provide one or more of the following functions:~~

~~prevent vertical movement of the casing hanger and annulus seal assembly, thereby improving the long-term sealing integrity of the annulus seal assembly;~~

~~resist greater upward loads than the lockdown device on the annulus seal assembly is capable of resisting, such as thermal expansion loads of the production casing string;~~

~~isolate the uppermost annulus seal assembly from the annulus between the production tubing and the production casing hanger;~~

~~provide a sealing interface to a subsea tree, tubing hanger, or tubing head;~~

~~provide a lockdown profile for the tubing hanger.~~

~~The lockdown bushing shall be designed such that it is retrievable through the drilling/completion riser and subsea BOP.~~

~~The lockdown bushing's sealing surface and seals along with its installation tool may be used as a subsea BOP test tool in some instances.~~

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Design

Design Load/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

setting loads;

overpull;

pressure, internal and external (including casing expansion loads);

thermal (including casing expansion loads and trapped fluids);

torsional;

impact;

releasing and/or retrieval loads;

tubing hanger pressure end loads;

tubing string suspension loads;

~~BOP test loads.~~

Pressure Rating

~~The manufacturer shall determine and document the internal and external pressure rating of a sealing lockdown bushing.~~

~~NOTE—Some lockdown bushings do not seal.~~

Testing

Validation

~~Validation of casing hanger lockdown bushing shall conform to 5.1.7. Validation for internal and external pressure shall be done in accordance with Table 5 with the same criteria as metal seals not exposed to retained fluids. The minimum validation criteria shall be in alignment with API 6A (group 4 mandrel hangers). The upward and downward load capacity shall be performed to verify the structural integrity of the lockdown bushing with three cycles at rated working load.~~

~~Validation may be done in combination (axial load vs. pressure) or done individually (axial load and pressure).~~

Factory Acceptance Testing

~~A dimensional check or drift test shall be performed on the lockdown bushing to confirm the minimum vertical bore is in accordance with the manufacturer's specification.~~

~~FAT of casing hanger lockdown bushings does not require pressure testing.~~

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Marking

~~Marking shall be in accordance with 5.5.1, including the following additional marking information:~~

~~PSL;~~

~~RWP (if pressure-containing);~~

~~temperature rating;~~

~~material class;~~

~~minimum vertical bore.~~

Bore Protectors and Wear Bushings

General

~~A bore protector protects annulus seal assembly sealing surfaces inside the wellhead (high-pressure) housing before casing hangers are installed. After a casing hanger is run, a correspondingly sized wear bushing is installed to protect the remaining annular sealing surfaces and the previously installed annular seal assemblies and casing hangers. They are not pressure-containing or pressure-controlling components. However, wear bushings may be designed to support BOP stack pressure test loading.~~

Design

Design Load/Conditions

~~Design shall meet the requirements of 5.1.5.~~

~~The following may apply:-~~

~~BOP test pressure loading;~~

~~radial loads;~~

~~drill pipe hang-off loads;~~

~~lockdown loads;~~

~~retrieval loads;~~

~~antirotation loads.~~

Minimum Vertical Bores for Full-opening Bore Protectors and Wear Bushings

~~The minimum vertical bores for full-opening or full-bore bore protectors and wear bushings should be as given in Table 33. Equipment conforming to this requirement shall be referred to as having full-opening bores. Reduced vertical bores may also be supplied.~~

Profile

~~Wear bushings and bore protectors shall have lead-in tapers top and bottom to avoid causing the bit or tool passing through them to hang up.~~

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~~Antirotation may be added as an optional feature.~~

~~Rated Working Pressure~~

~~NOTE—Bore protectors and wear bushings are not normally designed to retain pressure.~~

~~Materials~~

~~The materials used in bore protectors and wear bushings shall conform to the manufacturer's written specifications.~~

~~Factory Acceptance Testing~~

~~A dimensional check or drift test shall be performed on the bore protector or wear bushing to confirm the minimum vertical bore is in accordance with the manufacturer's specification.~~

~~NOTE—Bore protectors do not require pressure testing.~~

~~Marking~~

~~Marking shall be in accordance with 5.5.1, including the minimum vertical bore.~~

~~Corrosion Cap~~

~~When required by the user/purchaser, a means for injecting corrosion inhibitor fluids and venting trapped pressure may be provided.~~

~~The manufacturer shall document the service life of the corrosion cap and its cathodic protection.~~

~~Running, Retrieving, and Testing Tools~~

~~NOTE—See Annex H for tools for running, retrieving, and for testing all subsea wellhead components.~~

~~Overtrawlable Protection Structure~~

~~An overtrawlable protection structure shall be provided when requested by the user/purchaser to provide external protection from foreign objects dropped/dragged or snagged.~~

~~Wellhead Inclination and Orientation~~

~~NOTE—An inclination of 0.5° or less helps to ensure that future completion scenarios are possible. An inclination of between 0.5° and 1.0° can restrict options for tiebacks, well completion, and re-entry, but can be drilled by making some adjustments to rig position. Readings of more than 1° can lead to damage due to drill pipe key seating between the casing hanger and flex joint. An inclination greater than 1.25° can severely restrict future operations.~~

~~Submudline Casing Hanger and Submudline Annulus Seal Assemblies~~

~~General~~

~~Load limits and pressure ratings for the landing ring, the submudline casing hanger, and submudline annulus seal assembly shall be defined by the manufacturer.~~

~~The manufacturer shall document the submudline landing ring and casing hanger materials and interfaces when associated with casing or pipe.~~

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~~NOTE—Submudline casing hangers provide a suspension point for additional intermediate casing strings that cannot be accommodated by a standard conductor (low-pressure) housing or wellhead (high-pressure) housings. Submudline annulus seal assemblies provide pressure isolation between the submudline landing ring and submudline casing hanger. Submudline landing rings are integrally incorporated into the casing string below a wellhead (high-pressure) housing or conductor (low-pressure) housing. Submudline casing hangers suspend the next casing string, landing on and transferring their loads to the landing ring.~~

Design

~~NOTE—Submudline landing rings and casing hangers are integral parts of casing strings.~~

~~Design requirements and pressure rating methods assigned to like components in Section 8 shall not apply to submudline landing rings and submudline casing hangers. Design requirements shall conform to 10.1.2.~~

~~Equipment ratings should remain the same regardless of their location in the casing string. Submudline landing rings and casing hangers should not be subjected to the RWP nor test pressure associated with the low-pressure or high-pressure wellhead (high-pressure) housing when a landing ring is placed directly below these housings.~~

~~Submudline annulus seals, submudline annulus seal assemblies, and backup submudline annulus seal assemblies shall be treated as pressure-controlling equipment.~~

~~Submudline annulus seal assemblies shall be excluded from the pressure rating methods assigned to like components in Section 8 and given a pressure rating corresponding to the submudline landing ring and casing hanger.~~

~~The following loads may apply to submudline casing hangers:~~

~~casing loads;~~

~~overpull;~~

~~pressure, internal and external;~~

~~thermal;~~

~~torsional;~~

~~radial.~~

~~The following may apply to submudline annulus seals, submudline annulus seal assemblies, and backup submudline annulus seal assemblies:~~

~~setting loads;~~

~~thermal loads;~~

~~pressure loads;~~

~~releasing and/or retrieval loads.~~

Validation

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~~Submudline hangers shall conform to 5.1.7 and API 6A (group 3 or group 4 mandrel hangers). Testing for internal pressure shall validate the structural integrity of the hanger and shall be independent of the casing grade and thread.~~

~~Submudline annulus seal assemblies shall conform to Table 5 for subsea wellhead annulus seal assemblies.~~

Factory Acceptance Testing

~~A dimensional check or drift test shall be performed on the submudline hanger to confirm that the minimum vertical bore (see Table 33) conforms to the manufacturer's specification.~~

Marking

~~Marking for submudline casing hangers shall be per 8.6.4.~~

~~Marking for submudline annulus seal assemblies shall be per 5.5.1.~~

Specific Requirements—Subsea Tubing Hanger System

Design

General

~~The OD of the tubing hanger system shall be compatible with the ID of the BOP stack and marine riser system being used. The design should keep diameters to the minimum and minimize the length of large diameters in order to ease running and retrieving of the tubing hanger system through the ball/flex joint. The operating procedures should advise the limiting ball/flex joint angle for running and retrieving of the tubing hanger system. The design of tubing hanger systems shall conform to 5.1. The seals shall not engage in the sealing bore until the orientation is complete.~~

~~Additional requirements for subsea tubing hangers apply as follows:~~

~~the tubing hanger lockdown mechanism shall remain engaged under all documented tubing hanger loads; if a self-locking taper type of mechanism is used to lock the tubing hanger into an HXT, a secondary locking arrangement shall be incorporated;~~

~~installation load capacity of the orientation pin/key onto the helix/slot shall be documented;~~

~~tubing hanger shall allow for a minimum of one full thread recut in the body or ability to reestablish the thread, or tubing hanger shall be provided with saver sub functionality;~~

~~a method of protecting hydraulic lines and electrical penetrations at the bottom of the tubing hanger should be provided; for tubing hangers landing in a wellhead, provision for protection may not be possible due to casing hanger interface.~~

~~Annulus access may be through an outlet below the tubing hanger in the tubing head or horizontal tree body.~~

~~Where annulus access is through the hanger and into the tree connector cavity area, provision shall be made for sealing off the annulus bore.~~

~~Hydraulically actuated running tools shall be of a fail-as-is design, so loss of primary control pressure shall not release the tubing hanger from its running tool. There shall be positive indication that the running tool is correctly attached to the tubing hanger before supporting the weight of the tubing string. The hydraulic running~~

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~~tool shall be capable of release from the tubing hanger in the event of power or communication loss through activation of a secondary means to release tubing hanger running tool. The top of the running tool/orientation joint shall interface with the completion riser, tubing strings, or drill pipe as specified by the manufacturer. The top of the running tool/extension joint shall interface with the TBIR, as defined in API 17G.~~

~~NOTE—See Annex L for additional information on tubing hangers.~~

Design Load/Conditions

~~Design shall meet the requirements of 5.1.3.1.~~

The following may apply:

suspended weight;

overpull;

pressure, internal and external;

tubing hanger/running tool separation loads due to pressure;

thermal loads;

torsional loads;

radial loads;

oriented loads;

tree-reacting loads.

Threaded Connections

Tubing Hanger

~~The type of tubing threads on the hanger shall be specified by the user/purchaser. Identification markings shall conform to API 6A. Tubing threads should be coated to prevent galling when required by the thread type or material.~~

Running Tool

~~Tubing threads shall conform to API 5B or the manufacturer's written specification. The length of tool joint shall allow for use of tongs.~~

~~The load capacity of the tool shall not be inferred from the choice of end connections on the tools.~~

Running Tool Seals

~~All stab subs and other sealing elements shall have a minimum of one elastomer seal. If additional seals are used, hydraulic lock shall be avoided.~~

Vertical Bores

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~~The minimum vertical bore with and without profiles shall conform to the manufacturer's written specification. The effect of wall thickness reduction due to plug profiles in the tubing hanger shall be included in the design analysis and documented as required in 5.1.~~

~~The tubing hanger bores shall be drifted in accordance with manufacturer's written specifications. When specified by the manufacturer, the annulus bore shall include a plug catcher device, which may be integral or threaded to the hanger. When specified by the user/purchaser, the plug profiles shall be in nipples threaded into the bottom of the hanger.~~

~~For horizontal trees, an isolation sleeve shall be required to close off the tubing hanger side outlet during tubing hanger installation or retrieval. Refer to 9.1.10.2 for requirements.~~

~~Tubing Hanger/Crown Plugs~~

~~NOTE—Tubing hanger plugs used in vertical trees are used as a temporary closure device and, are not covered under the provisions of 9.1.6. Tubing hanger plugs used with horizontal trees are called crown plugs and are used as permanent pressure barriers.~~

~~Crown plugs shall meet the general design criteria, material, and testing requirements of an internal tree cap as specified in 7.12 and Table 5.~~

~~Rated Working Pressure~~

~~The tubing hanger shall have an RWP of either 5000 psi (34.5 MPa), 10,000 psi (69 MPa), or 15,000 psi (103.5 MPa) (see to 5.1.2.1). This rating shall be exclusive of the tubing connection at the bottom of the hanger. Any downhole flow (SCSSV control or injection) passages through the tubing hanger body shall conform to the additional pressure requirements defined in Table 6.~~

~~The RWP of the tubing hanger shall be equal to the tree pressure rating of either 5000 psi (34.5 MPa), 10,000 psi (69 MPa), or 15,000 psi (103.5 MPa). The tubing hanger lockdown mechanism and annulus seal assembly shall have a design capability to retain a pressure load of 1.1 times RWP for a vertical tree completion system. The tubing hanger lockdown mechanism and annulus seal assembly shall have a design capability to retain a pressure load of 1.5 times the RWP for a horizontal tree completion system.~~

~~Seal Barriers~~

~~There shall be a minimum of two seal barriers between the production and annulus bores of the tubing hanger and the environment.~~

~~Stab Design for SCSSV, Other Hydraulic, and Chemical Injection Control Lines~~

~~There shall be a minimum of two seal barriers between the SCSSV, other hydraulic, and chemical injection control line stabs of the tubing hanger and the environment in operation mode when the tree is installed.~~

~~On vertical tree applications, SCSSV control line stabs in the tubing hanger shall be designed so as to vent control pressure when the tree is removed. Where a spring-loaded relief valve is used on the SCSSV line, the pressure required to open it shall be documented. The SCSSV, other hydraulic, and chemical injection control stabs shall be designed to minimize the ingress of debris and seawater when the tree is removed. The pressure rating of the control line stabs shall be the same as or greater than the its control or injection pressure and shall be selected from 9.1.7.~~

~~On horizontal tree applications, the horizontal control line stab may contain an integral coupler with poppet check valve or other valve type for the purpose of isolating the wellbore completion fluid from the control line internal control fluid. However, the check valve shall not interfere with the intended function.~~

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Miscellaneous Tools

General

~~Miscellaneous tools, such as storage and test stands, emergency recovery tools, inspection stands, lead impression tools, wireline installed internal isolation sleeves (horizontal tree), shall be supplied as needed.~~

HXT TH Isolation Sleeve

~~TH isolation sleeve shall provide isolation of the production outlet to allow circulation of the production string during running/retrieval.~~

~~The following design requirements shall apply.~~

~~TH isolation sleeve shall be locked in place.~~

~~TH isolation sleeve RWP shall be the same as the tree system RWP.~~

HXT TH Protection Sleeve

~~During down hole operations, adequate protection of the TH internals, such as seal areas and landing/locking profiles, shall be provided by means of a deployable and retrievable protection sleeve.~~

~~The deployable and retrievable protection sleeve shall be configured for tool strings to pass in to and out of the bore. The protection sleeve shall be suspended and locked in place.~~

Materials

~~Materials shall conform to 5.2. Seal surfaces that engage metal-to-metal seals shall be inlaid with or be made from a corrosion resistant material that is compatible with well fluids, seawater, etc.~~

Testing

Validation

~~Validation of the tubing hanger shall conform to section 5.1.7. In addition, the tubing hanger lockdown shall be tested to a minimum of 1.1 times RWP for VXT or 1.5 times RWP for HXT from below and from above to 1.0 times RWP for both. Where annulus access devices (e.g. poppet, shuttle, sliding sleeve, etc.) and chemical injection stab barriers are incorporated into the tubing hanger design, these shall meet the requirements in Table 5.~~

Factory Acceptance Testing

Tubing Hanger

~~All tubing hangers shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic body test pressure of production and annulus bores shall be equal to or greater than 1.5 times RWP in accordance with the requirements in 5.4.5 and Table 6. All operating control or injection passages through the tubing hanger body shall be hydrostatically tested to 1.5 times their respective RWPs in accordance with 5.4.5 and Table 6.~~

~~A pup joint of tubing shall be installed on the hanger and the connection hydrostatic tested to manufacturer's written specifications.~~

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~~Tubing hanger internal profiles shall be drifted, and pressure tested with a mating plug or fixture to the manufacturer's written specifications. The pressure test for this profile and tubing plugs or crown plugs shall conform to Table 6.~~

~~Testing shall be conducted in accordance with the manufacturer's written specification to confirm the functionality of the primary and secondary operating and release mechanisms, override mechanisms, locking mechanisms, instrumentation, and control lines. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Tubing Hanger Running Tool~~

~~All wellbore pressure-containing or pressure-controlling components shall conform to the hydrostatic test requirements of 5.4.5 with the addition that the through-bores of the running tools shall be tested to a test pressure equal to at least 1.5 times RWP.~~

~~Components having multiple bores or ports shall have each bore or port tested individually if there is possibility of intercommunication.~~

~~Components that contain hydraulic control fluid shall be subjected to a hydrostatic body test in accordance with the requirements given in 5.4.7. After assembly and hydraulic testing, the equipment shall be flushed to meet the cleanliness requirements of SAE/AS 4059. The class of cleanliness shall be as agreed between the manufacturer and the user/purchaser.~~

~~Testing shall be conducted in accordance with the manufacturer's written specification to confirm the functionality of the primary and secondary operating and release mechanisms, override mechanisms, locking mechanisms, instrumentation, and control lines. Testing shall confirm that the actual operating forces/pressures fall within the manufacturer's documented specifications.~~

~~Marking~~

~~The subsea tubing hanger shall be marked in accordance with 5.5.1, with the additional marking information:~~

~~PSL;~~

~~RWP;~~

~~temperature rating;~~

~~material class of production bore;~~

~~material class of annulus bore;~~

~~minimum vertical bore;~~

~~tubing thread size and type.~~

~~Specific Requirements—Mudline Suspension Equipment~~

~~General~~

~~Introduction~~

~~Mudline suspension equipment shall conform to 8.14 except for submudline annulus seals.~~

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~~NOTE 1 — Mudline casing hangers, casing hanger running tools (landing subs), casing hanger landing rings, and tieback tools (tieback subs) are an integral part of the casing strings.~~

~~Design requirements and pressure rating methods assigned to similar components in Section 8 shall not apply to mudline suspension equipment.~~

~~Mudline suspension equipment used during drilling and/or run as part of the casing string includes the following (see Figure E.1):~~

~~landing rings;~~

~~casing hangers;~~

~~casing hanger running tools (landing subs);~~

~~tieback adapters (tieback subs);~~

~~abandonment caps.~~

~~These components shall be treated as “casing and tubing hanger mandrels” as set forth in API 6A.~~

~~NOTE 2 — Mudline conversion equipment for subsea completions includes tubing head assemblies (see Figure E.2).~~

~~Tubing head assemblies shall be designated as pressure-containing.~~

~~NOTE 3 — See Annex E for additional information on mudline suspension equipment.~~

~~Design~~

~~General~~

~~The general design requirements for mudline equipment shall conform to 5.1. If specific requirements for mudline equipment in Section 10 differ from the general requirements stated in 5.1, these specific requirements shall take precedence.~~

~~Rated Working Pressure~~

~~For each piece of mudline equipment, a RWP shall be determined in accordance with Table 34 and Annex E.~~

**Table 34—Maximum Allowable Stress Due to Pressure^a
(for Mudline Equipment Only)**

Allowable Stress	At Rated Working Pressure		At Test Pressure
	Suspension Equipment	Conversion Equipment	Suspension and Conversion Equipment
Membrane	Membrane stress = S_m		
	$0.8 \times S_{YST}$	$0.67 \times S_{YST}$	$0.9 \times S_{YST}$
Membrane + Bending	Membrane + bending = $S_m + S_b$ (where $S_m \leq 0.67 \times S_{YST}$)		
	$1.2 \times S_{YST}$	$1.0 \times S_{YST}$	$1.35 \times S_{YST}$
	Membrane + bending = $S_m + S_b$ (where $0.67 \times S_{YST} \leq S_m \leq 0.9 \times S_{YST}$)		
	$2.2 \times S_{YST} - 1.5 \times S_m$	N/A	$2.35 \times S_{YST} - 1.5 \times S_m$
Key: S_m is the calculated membrane stress.			
S_b is the calculated bending stress.			
^a Stresses given in this table shall be determined in accordance with the definitions and methods presented in Annex E.			

The RWP shall be inclusive of the pressure capacity of the end connections.

The test pressure shall be that which is required to cause any of the allowable stresses to occur in the critical cross section of the component when pressure and end loads due to test end caps or plugs are included.

The RWP of mudline suspension equipment shall be that which is required to cause these stresses to occur in the critical cross section of the component.

The RWP of mudline conversion equipment shall be that which is required to cause these stresses to occur in the critical cross section of the component.

Hanging/Running Capacity Rating

Rating Running Capacity

A rated running capacity shall be determined for each piece of mudline suspension equipment in the load path between the top connection of the running tool and the lower connection of the hanger that is run as part of the casing string. The rated running capacity is defined as the maximum weight that can be run below the mudline component. Rated running capacity is not the same as joint strength, ultimate tensile strength, or proof test load.

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~~Primary membrane stresses in the body at the rated running capacity shall not exceed 80 % of the minimum specified yield strength and shall be exclusive of internally applied pressure and externally applied global bending loads.~~

~~Rated Hanging Capacity~~

~~The rated hanging capacities shall be determined for each piece of mudline suspension equipment that hangs casing weight. The rated hanging capacity is defined as the maximum weight that can be suspended from the component at the rated location.~~

~~Compressive stresses at load shoulders shall be permitted to exceed material yield strength at the rated hanging capacity provided that all other performance requirements are satisfied.~~

~~Rated hanging capacities shall include the effects of full RWP. Both internal and external pressure shall be included. Primary membrane stresses in the body at the rated hanging capacities shall not exceed 80 % of minimum specified yield strength.~~

~~Rated hanging capacities shall be documented by the manufacturer for a given set of nested equipment in an assembly or for each component individually.~~

~~Outside and Inside Diameters~~

~~The manufacturer shall document minimum ID and maximum OD dimensions for mudline equipment. These values shall be based on machining dimensions and shall be stated in decimal form to the nearest 0.001 in. (0.02 mm). This requirement shall apply only to IDs that must pass (admit) other mudline components and to ODs that must pass through other mudline components. Outside dimensions shall exclude the expanded condition of expanding latches.~~

~~Flowby Areas~~

~~Manufacturers shall document the minimum flowby area and maximum particle size provided for each design, including:~~

~~flowby area while running through a specified weight of casing;~~

~~flowby area when landed in a specified mudline component;~~

~~critical velocity for running tool wash ports.~~

~~Temperature Ratings~~

~~Each component shall have a temperature rating as specified in 5.1.2.3.~~

~~Misalignment~~

~~The manufacturer shall document allowable inclination from vertical for drilling and production tieback.~~

~~Materials~~

~~Material Classes~~

~~Subsea mudline completion equipment shall follow material classes listed in Table 1.~~

~~NACE Requirements~~

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~~For material classes DD through HH (sour service), NACE MR0175 (all parts) requirements shall be limited to the internal pressure-containing and pressure-controlling components exposed to wellbore fluids. For example, sour service mudline hangers may include non-NACE external latch mechanisms and load rings.~~

~~NOTE—For the purposes of this provision, NACE MR0175 is equivalent to ISO 15156 (all parts).~~

Testing

~~Validation~~

~~Manufacturers shall perform validation and document results in conformance with 5.1.7.~~

Factory Acceptance Testing

Hydrostatic Testing

~~Hydrostatic testing of mudline suspension equipment shall not be required.~~

~~When included in the manufacturer's written specification, the test pressures shall not exceed the requirements of Table 34.~~

~~Hydrostatic testing of mudline conversion equipment shall be tested in conformance with 5.4.5.~~

Drift Testing

~~Drift testing shall not be required.~~

~~If drift testing is included in the manufacturer's written specification, then the requirements in API 5CT shall apply. The drift test may specify either individual component drift testing or assembly drift testing (i.e. hanger, running tool, and casing pups assembled together).~~

Stack-up and Fit Test

~~A stack-up and fit test shall not be required.~~

~~If stack-up and fit testing is part of the manufacturer's written specification, then the manufacturer shall document the requirements for measuring and/or recording axial and drift dimensions that shall be taken to confirm proper stack-up.~~

Marking and Documentation

~~Mudline suspension and conversion equipment shall be marked in accordance with 5.5.1, including the additional marking information.~~

~~size;~~

~~material class.~~

~~The following information shall be provided in system documentation as applicable:~~

~~RWP;~~

~~rated running capacity;~~

~~rated hanging capacity;~~

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~~minimum flow-by area;~~

~~maximum particle size;~~

~~drift diameter;~~

~~maximum allowable test pressure;~~

~~maximum make-up and breakout torque;~~

~~maximum wash port flow rate.~~

Mudline Suspension Landing/Elevation Ring

Description

The following may apply in the design of landing elevation ring:

~~shoulder load-bearing strength;~~

~~completion elevation above mudline;~~

~~centralization of casing hangers;~~

~~mud and cement return flowby area.~~

Design

The following may apply when designing the landing/elevation ring:

~~structural loads, including casing hanging loads and reduced area due to flowby profiles;~~

~~dimensional compatibility with other hangers;~~

~~dimensional compatibility with specified bit program;~~

~~welding requirements;~~

~~mud flowby requirements.~~

~~The minimum ID of each ring shall be selected to allow both the landing of subsequent casing hangers and the passage of bit sizes to be used.~~

Documentation

~~The manufacturer shall document any critical alignment and/or welding requirements for attachment of the landing/elevation ring to the conductor pipe.~~

Casing Hangers

General

End Connections

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~~The assembly of casing extensions, running tool, and casing hanger shall be done prior to shipment to the rig. This allows the handling and running of the casing hanger assembly as just another piece of casing.~~

Internal Profiles

The internal profiles of mudline casing hangers serve these functions:

lock and seal running tool (landing sub) and tieback adapters;

seat subsequent casing hangers;

seat tubing hanger (optional).

The lock and seal mechanism for the running tool and tieback adapters is usually the upper internal profile of the mudline casing hanger. The locking profile may be a thread or an internal locking groove for a cam-actuated locking mechanism. The running tool is usually designed to release with right-hand rotation.

Wash ports may be incorporated as necessary into each landing sub or casing hanger to provide a flow rate, without cutting out the port area. After the casing hanger has been landed and cemented, the wash ports are opened. After flushing out the casing riser annulus, the wash ports are closed. The purpose of washing out the casing riser area is to ensure that excessive cement has been removed from the casing hanger/running tool connection area.

Design

Design Load/Conditions

The following may apply:

casing loads;

pressure;

operating torque.

Flowby Area

Casing hanger minimum flowby areas shall be documented by the manufacturer for each casing hanger design configuration.

Particle Size

The maximum particle size shall be documented for each casing hanger design configuration.

End Connections

Standard API or other end connections provided on the casing hanger and running tool (landing sub) shall conform to the requirements of 7.1 through 7.6.

Adequate surface areas for tongs should be provided for installing the casing into the casing hanger and running tool (landing sub).

Casing Hanger Running Tools and Tieback Adapters

Description

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~~Casing hanger running tools shall be designed to provide a reversible connection between the mudline casing hanger and the casing hanger running tool. Tieback adapters shall be designed to provide a remote make-up connection between the mudline casing hanger and tieback adapter.~~

~~Casing hanger running tools may be either threaded (including an optional weight set) or cam-actuated as supplied by each individual manufacturer. Threaded running tools engage directly into the casing hanger. Cam-actuated tools engage in an internal locking groove inside of the casing hanger. Wash ports may be provided in the casing hanger or landing sub to allow for cleaning of cement from around the previously run hanger/landing sub connection.~~

~~NOTE Tieback adapters (tieback subs) are used to connect casing pipe joints to mudline suspension wellhead equipment for either surface wellhead completions or subsea completion purposes.~~

~~Mudline casing hangers running tools and tieback adapters shall be treated as pressure-controlling.~~

Design

Design Load/Conditions

The following may apply:

suspended weight;

pressure loads;

torque;

overpull;

environmental loads.

Threaded Running and Tieback Adapters

~~Threaded running tools shall be right hand release. Threaded tieback adapters and tieback profiles shall be right hand make-up.~~

~~The manufacturer shall document maximum flow rate through washout ports.~~

Abandonment Caps

~~Abandonment caps shall be designed to be pressure-containing and provide a means for detecting and relieving pressure prior to releasing the cap.~~

Mudline Conversion Equipment for Subsea Completions

Description

~~Mudline conversion equipment for subsea completions shall provide the interface between mudline suspension equipment and subsea completion equipment (see Figure E.2).~~

~~Mudline conversion equipment shall be treated as pressure-controlling.~~

Design

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~~The lower end of mudline conversion equipment shall provide a load shoulder (or threaded) and sealing interface for at least two tieback adapters and casing strings. The conversion may also provide a centralizing and load-bearing feature to provide structural integrity to transfer applied loads to the surface casing or conductor pipe. The mudline conversion hardware also shall feature the necessary adjustment capability to accommodate the spacing between the mudline wellhead casing hangers, the surface pipe end, and the subsea completion hardware.~~

~~The upper end of mudline conversion equipment shall feature a tubing head assembly to interface with a high-pressure completion riser, the subsea tubing hanger, and subsea tree.~~

~~Care shall be exercised when specifying in situ testing of mudline conversion equipment such that the suspension equipment does not see higher pressures than pressure rating for the well's casing, the tieback adapter, or the casing strings installed above and below the casing hanger.~~

~~NOTE—The casing riser string that attaches to the tubing head is often the defining requirement for pressure rating and equipment size for a mudline conversion system. Usually, this riser string has a thicker wall and/or is made from the higher-strength materials required to withstand both internal pressure and external environmental loads.~~

~~The user/purchaser shall define the loads, including, but not limited to, pressure rating and tension requirements for a mudline conversion system.~~

~~Bodies of mudline conversion tubing head assemblies shall be treated as pressure-containing.~~

~~Rated Working Pressure~~

~~The RWP for the tubing head assembly pressure boundary shall be based on the RWP of the casing riser used to complete the well and install tubing strings. Selection of the RWP shall conform to Table 2.~~

~~Factory Acceptance Testing~~

~~All tubing head assemblies shall be hydrostatically tested prior to shipment from the manufacturer's facility. They shall be tested to the requirements of this specification with the addition that the tests (including PSL 2) shall have a secondary holding period of not less than 15 minutes. The hydrostatic test is performed to confirm the pressure integrity of the housing pressure boundary.~~

~~The overall hydrostatic body test pressure shall be determined by the lesser of either the RWP of the tubing head's body or the high-pressure casing-string riser's pressure rating, as defined in Annex E. Typical pressure ratings for the tubing head assembly are listed in Table 35.~~

~~Tubing Hanger System—Mudline Conversion Equipment for Subsea Completions~~

~~All design, materials, and testing of the tubing hanger system shall conform to Section 9.~~

~~Specific Requirements—Drill-through Mudline Suspension Equipment~~

~~General~~

~~All pressure-containing and pressure-controlling parts included as part of the drill-through mudline suspension equipment shall be designed to meet all the requirements of the specified material class and NACE MR0175 (all parts) for the casing hanger housing, and all of the components installed inside it.~~

~~Mudline suspension hardware external to the drill-through housing may be non-NACE depending on the surface casing design. The innermost casing riser string that attaches to the drill-through casing hanger housing is often the defining requirement for pressure rating and equipment size for a drill-through system.~~

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~~Usually, this riser string has a thicker wall and/or is made from the higher-strength materials required to achieve a higher-than-average pressure rating.~~

~~Drift diameter, NACE or non-NACE service, connector size and strength, and material availability shall be determined in accordance with the well's requirements.~~

~~NOTE—See Annex M for typical drill-through mudline equipment.~~

~~Drill-through mudline suspension equipment shall be marked in accordance with 10.1.5.~~

~~External Drill-through Casing Hangers (Outside of the Drill-through Casing Hanger Housing)~~

~~All drill-through mudline casing hangers external to the drill-through casing hanger housing shall be designed and manufactured in accordance with 10.1 through 10.4.~~

~~External drill-through mudline casing hanger bodies shall be treated as pressure-controlling.~~

~~Drill-through Casing Hanger Housing~~

~~General~~

~~The drill-through casing hanger housing lands inside the last mudline suspension casing hanger landing ring. It provides pressure integrity for the well, suspends the intermediate and subsequent casing strings, the tubing hanger when installed and transfers external loads back into the surface casing hanger. Internally, it has a landing shoulder for the subsequent hangers and an internal profile for a running/tieback tool. The subsea tree attaches and seals to the upper connection after the drilling phase is complete.~~

~~Drill-through casing hanger housings shall be treated as pressure-containing.~~

~~Design~~

~~Design Load/Conditions~~

~~The following may apply:~~

~~riser forces (drilling, production, and workover, including tension);~~

~~fatigue assessment;~~

~~subsea tree loads;~~

~~pressure;~~

~~radial loads;~~

~~thermal loads;~~

~~environmental loads;~~

~~flowline loads;~~

~~suspended-casing loads;~~

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~~surface casing hanger/conductor (low-pressure) housing reactions;~~

~~tubing hanger reactions;~~

~~riser and tree connector loads.~~

Connections

Top Connection

The top connection should be of a hub or mandrel type (see Figure 15) as specified by the manufacturer. The gasket profiles shall be manufactured from or inlaid with CRM as specified in 5.3.3.

Bottom Connection

The high-pressure housing attaches to the top of the intermediate casing to form the basic foundation of a subsea well. If the bottom connection is being welded, it shall be prepared for a full-penetration butt weld. If threaded, the type of casing thread on the housing shall be as specified in API 6A.

Pup Joint

The wellhead (high-pressure) housing may have a pup joint that is factory-welded on to ease field installation or threaded into the housing.

Dimensions

The dimensional requirements are as follows.

The minimum bore of the housing shall not be less than the drift diameter of the intermediate casing. The manufacturer shall document the through-bore size.

Dimensions of the drill-through casing hanger housing pressure boundary (see Figure 15) shall be in accordance with the manufacturer's written specification.

The drill-through casing hanger housing minimum flowby area shall be documented by the manufacturer.

Rated Working Pressure

The RWP for the drill-through casing hanger housing pressure boundary shall be based on the RWP of the casing riser used to drill and complete the well. Selection of the RWP shall conform to Table 35.

Table 35—Drill-through Casing Hanger Housing—Pressure Rating and Test Pressure

Rated Working Pressure		Hydrostatic Body Test Pressure	
psi	(MPa)	psi	(MPa)
5000	(34.5)	7500	(51.8)
7500	(51.8)	11,250	(77.57)

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10,000	(69.0)	15,000	(103.5)
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Factory Acceptance Testing

~~All drill-through casing hanger housings shall be hydrostatically tested prior to shipment from the manufacturer's facility. They shall be tested to the requirements of this specification, with the addition that the tests (including PSL 2) shall have a secondary holding period of not less than 15 minutes.~~

~~The overall hydrostatic body test pressure shall be determined by the lesser of either the RWP of the housing's body or the high-pressure casing string riser's pressure rating, or the pressure rating of innermost drill-through mudline casing hanger that will be attached to the production casing string, as defined in Annex E.~~

~~NOTE—Pressure ratings for the drill-through casing hanger housing body are listed in Table 35.~~

~~Hydrostatic FAT of drill-through casing hanger housings is mandatory and shall be performed in accordance with 5.4.5. A dimensional check or drift test shall be performed on the housing to confirm the minimum vertical bore.~~

Internal Drill-through Mudline Casing Hangers

General

~~Internal drill-through mudline casing hangers shall have provisions for an annulus seal assembly and support loads generated by BOP test pressures above the hanger and loads due to subsequent casing strings. Means shall be provided to transfer casing load and test pressure load to the drill-through casing hanger housing or to the previous casing hanger.~~

~~Bodies of internal drill-through mudline casing hangers shall be treated as pressure-controlling.~~

Design

Design Load/Conditions

The following may apply:

suspended weight;

overpull;

pressure, internal and external;

thermal;

torsional;

radial;

impact.

Threaded Connections

~~The type of casing threads on the hanger shall be as specified in API 6A.~~

~~Vertical Bore~~

~~Internal drill-through casing hangers with a minimum vertical bore conforming to Table 33 shall be designated as full-opening. Internal drill-through casing hangers with reduced bores are allowed but shall be designated as reduced-bore. The manufacturer shall document their designation, along with the reduced-bore value, when applicable.~~

~~Casing Hanger Ratings~~

~~Internal drill-through casing hanger load and pressure ratings shall conform to 8.6.2.4.~~

~~Flowby Area~~

~~Internal drill through casing hanger flowby areas shall conform to 8.6.2.5.~~

~~Testing~~

~~Validation~~

~~Validation of drill-through mudline casing hangers shall conform to 5.1.7. Testing for internal pressure shall be performed to validate the structural integrity of the hanger and shall be independent of the casing grade and thread.~~

~~Factory Acceptance Testing~~

~~A dimensional check or drift test shall be performed on the internal drill-through casing hanger to confirm the minimum vertical bore.~~

~~NOTE Hydrostatic testing is not required as part of the FAT of internal drill-through casing hangers.~~

~~Internal Drill-through Annulus Seal Assemblies~~

~~General~~

~~Internal drill through mudline annulus seal assemblies, including backup annulus seal assemblies, shall be treated as pressure-controlling.~~

~~Design~~

~~Design Load/Conditions~~

~~The following may apply:~~

~~setting loads;~~

~~thermal loads;~~

~~pressure loads;~~

~~releasing and/or retrieval loads.~~

~~Rated Working Pressure~~

~~Internal drill-through annulus seal assembly shall contain pressure from above equal to the RWP of the casing hanger (see 11.4.2.5).~~

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~~The manufacturer shall specify the RWP from below if it is different than the RWP from above.~~

~~Lockdown~~

~~The internal drill-through annulus seal assembly shall be locked to the casing hanger and/or wellhead (high-pressure) housing using a lock mechanism that allows retrieval without damage to the seal surfaces, in the event of seal failure.~~

~~Factory Acceptance Testing~~

~~FAT for either the annulus seal assembly or backup annulus seal assembly shall not apply.~~

~~Internal Drill-through Bore Protectors and Wear Bushings~~

~~Design~~

~~Design Load/Conditions~~

~~The following may apply:-~~

~~BOP test pressure loading;~~

~~radial loads;~~

~~drill pipe hang-off loads;~~

~~lockdown loads;~~

~~retrieval loads;~~

~~antirotation loads.~~

~~It is not required for bore protectors or wear bushings to meet the requirements of Section 5.~~

~~Vertical Bores~~

~~Bore protectors and wear bushings conforming to Table 33 shall be designated as full-opening. Bore protectors and wear bushings with reduced bores are allowed but shall be designated as reduced bore. The manufacturer shall document their designation, along with the reduced bore value, when applicable.~~

~~Rated Working Pressure~~

~~NOTE—Bore protectors and wear bushings are not required to retain pressure.~~

~~Lockdown/Antirotation~~

~~Means shall be provided to restrain or lock the wear bushings or bore protector within the housing.~~

~~Materials~~

~~The materials used in bore protectors and wear bushings shall conform to the manufacturer's written specifications.~~

~~Testing~~

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~~A dimensional or drift test shall be performed on the bore protector or wear bushing to confirm that the minimum vertical bore is in accordance with the manufacturer's specification.~~

~~NOTE—Bore protectors do not require pressure testing.~~

~~Tubing Hanger System—Drill-through Mudline Equipment for Subsea Completions~~

~~All design, materials, and testing of the tubing hanger system shall be in accordance with Section 9.~~

For API Committee Work Only

~~(informative)~~

~~Subsea Wellhead~~

~~The subsea wellhead is normally run from a floating drilling rig and is located at the mudline. It supports the casing strings and seals off the annuli between them. It is used in conjunction with a subsea BOP stack that locks and seals to the high-pressure wellhead (high-pressure) housing. The subsea tree locks and seals to the high-pressure housing after drilling is complete. Figure A.1 illustrates the items of equipment used in a subsea wellhead.~~

~~Subsea wellhead systems can be run with a TGB/PGB (guideline), TGB/GRA (guidelineless) or without (guidelineless) and can incorporate alternative means of orientation, if required.~~

~~Subsea wellheads may be used for subsea completions or tied back to a surface completion. Major items of equipment used with subsea wellhead are:~~

~~TGB;~~

~~PGB or GRA;~~

~~conductor (low-pressure) housing;~~

~~wellhead (high-pressure) housing;~~

~~casing hangers (intermediate and production);~~

~~seal assemblies (packoffs, contingency packoffs, lockdown bushings);~~

~~bore protectors and wear bushings;~~

~~corrosion caps;~~

~~running tools.~~

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4	TGB running tool	12	wear bushing
2	conductor (low pressure) housing running tool	13	annulus seal assembly
3	wellhead (high pressure) housing running tool	14	intermediate casing hanger
4	casing hanger running tool (drill pipe or fullbore)	15	housing bore protector
5	test tool	16	wellhead (high pressure) housing
6	wear bushing	17	surface casing
7	annulus seal assembly	18	conductor (low pressure) housing

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8	production casing hanger	19	PGB
9	wear bushing	20	TGB
10	annulus seal assembly	21	conductor casing
14	intermediate casing hanger	22	seafloor
		23	guidelines

Figure A.1—Subsea Wellhead

~~(informative)~~

~~Purchasing Guidelines~~

~~General~~

~~Annex B provides recommended guidelines for inquiry and purchase of equipment covered by this specification.~~

~~Typical Wellhead and Tree Configurations~~

~~Examples of typical wellhead and tree configurations are shown in Annexes A, E, M, O, and P.~~

~~Product Specification Levels~~

~~PSLs are defined in 5.4. PSLs apply to pressure-containing and pressure-controlling parts and assembled equipment as defined in this specification. Determination of the PSL is the responsibility of the user/purchaser. Selection of PSL can depend on whether equipment is primary or secondary equipment, as defined in API 6A. For this specification, primary equipment shall include, as a minimum, the tubing head/high-pressure housing, the first two actuated (master and/or wing) valves downstream of the tubing hanger, the lower tree connector, and any other flowline or isolation valve in direct communication with the wellbore upstream of the second actuated valve.~~

~~The following are recommendations for selection, summarized by the decision tree in Figure B.1.~~

~~PSL 2: recommended for general (nonsour) service at working pressure 5000 psi (34.5 MPa); recommended for secondary equipment for working pressure of 10,000 psi (69 MPa) or below.~~

~~PSL 3: recommended for primary equipment in sour service, all working pressures, and general service above pressures of 5000 psi (34.5 MPa); recommended for primary and secondary equipment, sour or general service, for pressures above 10,000 psi (69 MPa) or for maximum temperature ratings above 250 °F (121 °C).~~

~~Other considerations that can lead the user/purchaser to consider PSL 3 over PSL 2 include water depth, composition of retained or injected fluids, field infrastructure, difficulty of intervention, acceptance of risk, sensitivity of environment, and useful field life.~~

~~PSL 3G: same recommendations as for PSL 3, with additional considerations for wells that are gas producers, have a high gas/oil ratio, or are used for gas injection.~~

~~PSL 4S: reserved for HPHT equipment (see Annex D).~~

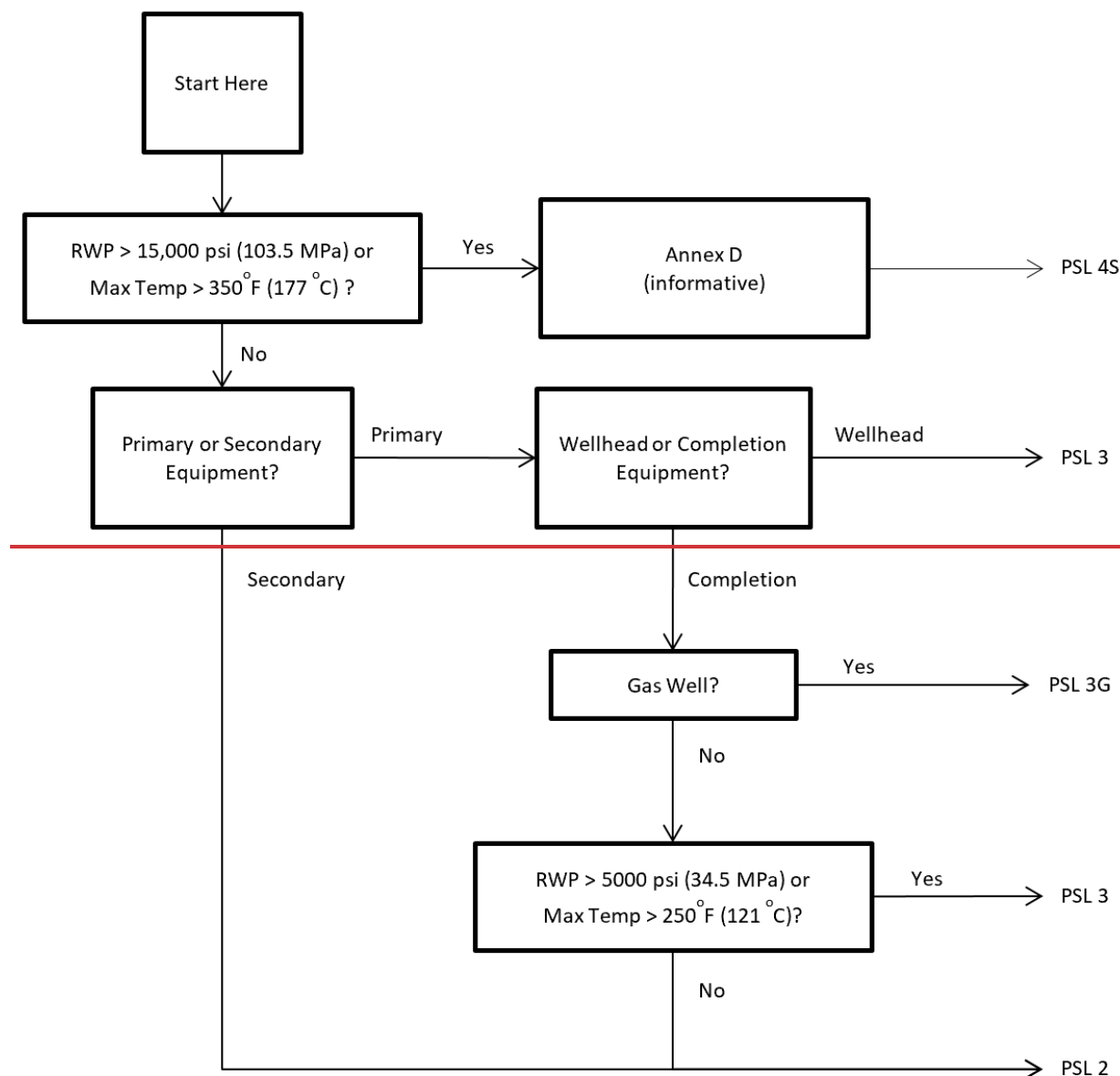


Figure B.1—PSL Decision Tree for Subsea Equipment

Material Class

Material class manufacturing requirements are given in API 6A and in Table 1. Material class shall be determined by the user/purchaser.

The following may apply:-

pressure;

temperature;

composition of produced or injected fluid, particularly H_2S , CO_2 , and chlorides;

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~~pH of water phase or brine;~~

~~exposure to salt water during installation or operation;~~

~~use of inhibitors for scale, paraffin, corrosion, or other reasons;~~

~~possibility of acidizing and concentration of acidizing solutions;~~

~~anticipated production rates;~~

~~sand production and other potential for erosion;~~

~~anticipated service life;~~

~~future operations that can affect pressure, temperature, or fluid content;~~

~~risk analysis.~~

~~NOTE Corrosion, stress-corrosion cracking, erosion-corrosion, and sulfide stress cracking are all influenced by the interaction of the environmental factors and the production variables. Other factors not listed can also influence fluid corrosivity.~~

Data Sheets

General

~~This section provides suggested data sheets that can be used for enquiry and purchase of subsea wellhead and tree equipment.~~

~~The data sheets are designed to perform three functions:~~

~~assist the user/purchaser in determining requirements;~~

~~assist the user/purchaser in communicating needs and requirements, as well as information on the well environment, to the manufacturer in designing and producing equipment;~~

~~facilitate the communication regarding user/purchaser requirements, relative to the supplier's options and/or capabilities such that a common understanding is agreed.~~

~~A copy of the data sheets should be completed as accurately as possible. The typical configurations should be referred to, as required, to select the required equipment. The decision tree in Figure B.1, together with its instructions, provides the recommended practice as to which PSL each piece of equipment should be manufactured. A copy of the data sheet should then be attached to the purchase order or request for proposal.~~

~~Data sheets from API 6A may also be useful in selecting specific wellhead equipment components.~~

Well Data Sheet

~~User/purchaser to provide a piping and instrumentation diagram (P&ID) or sketch of the well design (see API 96), along with the following.~~

Location and water depth

	Description	Comments
Number of wells		
Well (or block) identifier		
Well location(s)	Block: Mercator location X: Mercator location Y:	Latitude: Longitude:
Water depth	Feet (meters)	
Seabed temperature	°F (°C)	

Reservoir flow rates and pressures

		Comments
FWHP (at wellhead)	psi (MPa)	
FWHT	°F (°C)	
SIWP	psi (MPa)	

Meteorcean data

	Description	Comments
Current profile vs. water depth	Water depth-velocity ft (m) — ft/s (m/s)	
Current direction	Aligned to waves Other specify:	
Significant and maximum wave height	H_s : ft (m) H_{max} : ft (m)	
Wave period	T_p : sec	
Wave spectrum	JONSWAP Pierson-Moskowitz Other specify:	

Drilling plan

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Type of Drilling Vessel	Plan for Well
Jackup rig	Drill and abandon
Moored semi	Drill and complete
DP semi	Drill, temporary abandon, then complete
Moored drillship	Other specify:
DP drillship	
Completion vessel (only)	

Wellhead interface

	Baseline	Options
Wellhead type	Mudline suspension Subsea	Other specify:
Wellhead size	48 ³ / ₄ "	46 ³ / ₄ " Other specify:
Wellhead RWP	10,000 psi (69.05 MPa) 15,000 psi (103.5 MPa)	Other specify:
Wellhead top external profile	Specify:	
Wellhead gasket type	Specify:	
Shallow water flow system?	No	Yes Specify size (OD/wall):
Rigid lock/preloaded high-pressure housing (for bending/fatigue)	No	Yes
Guidance	Guideline (GL) Guidelineless (GLL) Funnel-up	Orientation required Specify:
Surface pipe installation	Drilled (requires TGB) Jettied Specify size (OD/wall):	Drill-ahead Other specify:-
On template?	No	Yes specify:

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	Baseline	Options
Casing program	$20" \times 13\frac{3}{8}" \times 9\frac{5}{8}"$ $20" \times 13\frac{3}{8}" \times 10\frac{3}{4}"$ Provide well diagram:	Other specify:
Casing thread profile (type)	Buttress	Other specify:
Number and size of submudline hangers suspended in wellhead	Provide well diagram:	Other specify:
Number and size of liner hangers to be suspended downhole	Provide well diagram:	Other specify:
Casing hanger lockdown bushing?	Yes No	
Anticipated tubing hanger completion	In the wellhead In the lockdown bushing In a separate tubing head	HXT Other specify:
Well deviation angle (from vertical)	Provide well diagram:	Other specify:
Distance from mudline to top of surface pipe or high-pressure wellhead (high-pressure) housing	TGB stack up height 40–15 ft (3–4.6 m)	Other specify:
Seabed hydrates anticipated	Yes No	
Outlet extension on conductor (low-pressure) housing	Yes No	With shut-off valve Other specify:
Marine drilling riser loads (i.e. normal, extreme, accidental, and fatigue) and load combinations (see API 17A)		Vessel RAO:

Subsea Completion and Tree Data Sheet

User/purchaser to provide a P&ID or sketch of the tree and flowline system (see Figure B.2 for examples), along with the following.

Reservoir general information

		Comments
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Gas	SCFD (m^3/d)	
Oil or condensate	BPD (m^3/d)	
Water	BPD (m^3/d)	
FWHP (at wellhead)	psi (MPa)	
FWHT	$^{\circ}\text{F}$ ($^{\circ}\text{C}$)	
SIWP	psi (MPa)	
Commingling zones?	<input type="checkbox"/> Yes <input type="checkbox"/> No	
Completion type	Specify (open hole, cased well, gravel pack, horizontal, staged, etc.):	
Producing life	Years	
Annulus gas lift location(s)	Not required Required, provide well diagram:	

Reservoir fluid properties

	Description	Comments
Reservoir pressure	psi (MPa)	
Reservoir temperature	$^{\circ}\text{F}$ ($^{\circ}\text{C}$)	
Reservoir properties		
Fluid type	<input type="checkbox"/> Oil <input type="checkbox"/> Gas	Hydrocarbon chain (C_x) % list
Gas-oil ratio	scf/bbl (m^3/m^3)	
API gravity	$^{\circ}\text{API}$	
Gas (specific) gravity		
Condensate yield (GOR)	bbl/scf (m^3/m^3)	
H_2S	psi pp (MPa pp)	
CO_2	psi pp (MPa pp)	
Paraffin	Mass % Deposition rate:	
Asphaltenes	Mass %	

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Formation water salinity or dissolved NaCl concentration	Mass % parts per thousand (ppt): ‰	
Formation water pH		
Sand production	Sand rate: lb/bbl (g/m ³) of produced fluid- Particle size (micron):-	

Downhole interface

	Description
Tubing size	OD, weight: Coupling OD/upset OD: Drift diameter: Material type/grade:
Annular pressure compensation/thermal cap	Required? <input type="checkbox"/> Yes <input type="checkbox"/> No
Subsurface safety valve (SCSSV)	Number of SCSSVs: Model: Size (OD, bore): RWP:— Hydraulic RWP Number of lines: Electric power:
Other downhole hydraulic/chemical injection lines	Number of lines: RWP: OD, weight: Material type/grade:
Downhole electric/fiber optic lines	Number of lines: OD: Signal or power: Type (coax, shielded, quad, etc.):

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	Description
Wireline plug model, type (plug profile), size, and pressure rating for tubing hanger production bore	Upper crown plug (HXT) specify: Lower crown plug (HXT) specify: Tubing hanger plug (VXT)
Bottom tubing hanger saver sub/blast joint for production bore (OD, bore, length, thread type/size)	Specify:
Wireline plug model, type (plug profile), size, and pressure rating for tubing hanger annulus bore, for multi bore tubing hangers, if applicable	Tubing hanger plug (VXT) Isolation check valve (VXT, optional)
Bottom tubing hanger tail sub/plug catcher for annulus bore (OD, bore, length, thread type/size), for multi bore tubing hangers, if applicable	Specify:
Minimum diameter of production bore	Specify:
Bottom connection for SCSSV line(s)	Specify:
Bottom connection for downhole chemical line(s), if applicable	Specify:
Bottom connection for other downhole hydraulic line(s), if applicable	Specify:
Bottom connection for electrical line(s), if applicable	Specify:
Bottom connection for optic line(s), if applicable	Specify:

Anticipated well tieback (see API 17A)

Type of Tieback to Host	Comments (Including Offset Distance)
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Fixed-platform tieback	Multi-well cluster-to-manifold application
Floating (compliant) production tieback	On template wells
To another subsea completion	
Single-satellite well	Daisy-chained (connected along a common flowline)
	Flowline pair (round trip pigging)

Host field and topsides information

	Description	Comments
Host location	Block: Mercator location X:	Latitude:-
Water depth	ft (m)	
Offset distance	miles (km)	
Separator pressure	psi (MPa)	
Process capacity	Oil [BPD (m ³ /d)]: Gas [SCFD (m ³ /d)]:	
Slug-catcher size, if any	bbl (m ³)	
L-Tubes: No. and size		
L-Tubes: No. and size		
Surface air temperature	Minimum: °F (°C)	
Surface water temperature	Minimum: °F (°C)	
Seabed temperature	°F (°C)	

Service life requirements

Subsea Service Life		Reusability	
Baseline	Options	Baseline	Options
40-year service life	20-year service life	Do not reuse	Refurbishment and reuse
	Other specify:		Other specify:

Completion plan

Type of Drilling Vessel	Plan for Well Completion
-------------------------	--------------------------

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Jackup rig	Drill and complete
Moored semi	Complete on previously drilled well
DP semi	Well flow back/clean up:
Moored drillship	To rig
DP drillship	To host
Completion vessel (only)	Completed then shut-in (dormant)
Rigless vessel:	Other specify:
Marine drilling riser loads (i.e. normal, extreme, accidental, and fatigue) and load combinations (see API 17A)	Vessel RAO
TBIRS or OWIRS loads (i.e. normal, extreme, accidental, and fatigue) and load combinations (see API 17G)	

Intervention plan (see API 17G)

Type of Intervention	Plan for Well Intervention
Jackup rig	Wireline intervention
Moored semi	Coiled tubing intervention
DP semi	Fluid circulation/bull head intervention
Moored drillship	Tree pull/refurbish/replace
DP drillship	Downhole hardware/tubing pull/replace
Completion vessel (only)	Pull/reinstall tubing hanger
Rigless vessel:	Zone recompletion
Construction/crane vessel	Side track and recompletion
Lightwell intervention vessel	Wellhead (size, RWP, top profile, bore) specify:
BOP/TBIRS on well	
Marine drilling riser loads (i.e. normal, extreme, accidental, and fatigue) and load combinations (see API 17A)	Vessel RAO
TBIRS or OWIRS loads (i.e. normal, extreme, accidental, and fatigue) and load combinations	

Tree general information

Tree	Description	Guidance/Orientation
------	-------------	----------------------

Service	Injection: <input type="checkbox"/> Water <input type="checkbox"/> Gas Production: <input type="checkbox"/> Oil <input type="checkbox"/> Gas	
Type	VXT HXT Mudline completion Other specify:	Diver-assist Guideline (GL) Guidelineless (GLL) Funnel-up
Tubing hanger completion	In the wellhead In the wellhead lockdown bushing In a separate tubing head In the HXT Other specify:	No orientation required TBIR orientation With BOP orienting pin With BOP connector Wellhead orientation Tubing head orientation

Tree size and classes

	Baseline	Options
Production valve size	Production bore (ID) (API 6A):	Min. drift, specify:
Annulus valve size	Nominal 2 in.	Other specify:
RWP (see 5.1.2 and Annex D)	5000 psi (34.5 MPa) 10,000 psi (69.05 MPa) 15,000 psi (103.5 MPa)	Other specify:
PSL (see Figure B.1)	2 3 3G — component/assembly	Other specify: 3G — upper level/tree

Material class (see Table 1)	Production bore:	Annulus bore:
	DD	DD
	EE	EE
	FF	FF
	HH	HH
Temperature class (see 5.1.2 and Annex D)	V	Other specify:
	X	
Wellhead gasket retention mechanism	Tubing head connector	
	Tree connector	

Valves on trees (see Figures 1 through 4)

Valve	Type	Quantity	Options	Override/
PMV	Fail-closed	1	2	Override-
PWV	Fail-closed			Override
PSV	Fail-closed			Override
XOV	Upstream of PWV/AWV Fail-closed			Override
	Downstream of PMV/AWV Fail-closed			Position indicator
AMV	Fail-closed	1 (VXT/HXT)		Override
AWV	Fail-closed	1 (VXT/HXT)		Override-
ASV	Fail-closed			Override
(for VXT)	Manual			Position indicator
AAV or WOV	Fail-closed			Override-
AIV	Fail-closed			Override-
(for tubing head)	Manual			Position indicator

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TST	Manual			
THST	Manual			
GIT	Fail-closed	P&ID	1 valve	Override
	Manual	Number specify:	1 valve + check valve	Metering valve
	Check valve			
CID	Fail-closed	P&ID	1 valve + check valve	Override
	Manual	Number specify:	2 valves	Metering valve
SV	Manual	P&ID		
HYD	Manual	P&ID	1 valve + check valve	
		Number specify:		
Tubing — hanger gallery (for HXT)	Manual	P&ID		

Tree-mounted chokes

Type	Description	Options
Production choke (PCV)	Flow coefficient:-	Check all options required:-
Injection choke (ICV)	Graph:-	Hydraulic actuator <input type="checkbox"/> Electric
	Fixed orifice size:-	Manual/operator <input type="checkbox"/> Override
	Specify C_v (K_v):	Insert retrievable
	Temperature:-	Adjustable, specify steps:-
	High:-	Fixed
	Low:-	Visual position indicator
	Body:-	Electronic position indicator (LVDT)
	RWP:-	Other specify:-

<p>Gas lift choke (to annulus bore) (GLCV)</p>	<p>Flow coefficient:-</p> <p>Graph:-</p> <p>Fixed orifice size:</p> <p>Specify C_v (K_v):</p> <p>Temperature:</p> <p>High:</p> <p>Low:</p> <p>Body:</p> <p>RWP:</p> <p>Full bore size:</p>	<p>Check all options required:</p> <p>Hydraulic actuator <input type="checkbox"/> Electric</p> <p>Manual/operator <input type="checkbox"/> Override</p> <p>Insert retrievable</p> <p>Fixed</p> <p>Adjustable, specify steps:</p> <p>Visual position indicator</p> <p>Electronic position indicator (LVDT)</p> <p>Other specify:</p>
<p>Production orifice valve (POV)</p>	<p>Specify C_v (K_v):</p> <p>Low temperature, specify:</p> <p>High temperature, specify:</p> <p>Valve size, specify:</p> <p>RWP:</p> <p>Full bore size:</p> <p>Fixed orifice size:</p>	<p>Check all options required:</p> <p>Hydraulic fail open (full bore) <input type="checkbox"/> Electric</p> <p>Manual/operator <input type="checkbox"/> Override</p> <p>Visual position indicator</p> <p>Other specify:</p>

Sensors

	Baselining	Options
Flow meter (see API 17S)	<p>Yes:</p> <p>Single-phase</p> <p>Multi-phase</p> <p>No</p>	<p>Remote sampling</p>
Production bore pressure/temperature sensor	<p>Yes, specify:</p> <p>No</p>	<p>P&ID</p> <p>Between PMV & PWV</p> <p>Downstream of PCV</p>
Annulus bore pressure/temperature sensor	<p>Yes, specify:</p> <p>No</p>	<p>P&ID</p> <p>Upstream of AMV</p>

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		Between AMV and AWW Downstream of AWW
Leak detection	Yes, specify: No	
Erosion monitoring	Yes, specify: No	
Sand detection	Yes, specify: No	
Pig detector	Yes, specify: No	See part o) Flow assurance—Pigging for other requirements

Flowline connections

	Baseline	Options
Flowline connection location	Subsea tree Tubing head	Other specify:
Flowline type	Rigid pipe, specify: Size, RWP Design code	Flexible pipe, specify: Size, RWP Design code (see API 17B, API 17J, API 17K)
Flowline connection type	17SV flange Vertical hub Horizontal hub (fixed) Horizontal hub (extend) Single bore Size, RWP, specify:	17SS flange Horizontal connector (fixed) Horizontal connector (extend) Multi-bore Size, RWP, specify: Production bore
Snag load protection	Not required	Required, specify: At flowline connection
Dropped object protection	Not required	Required, specify:

Flowline load design basis (see API 17R)	Specify:	Hydrate remediation in connector
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Flow assurance

	Baseline	Options
Downhole chemical injection	Not required	Required, specify:- Purpose (corrosion, scale, hydrate, paraffin) Chemical- Injection pressure
Tree chemical injection	Not required	Required, specify:- Purpose (corrosion, scale, hydrate, paraffin) Chemical- Injection pressure
Gas lift	Not required	Required, specify:- Injection pressure Injection flow rate [scfd (m ³ /d)] Gas lift isolation valve: <input type="checkbox"/> Yes <input type="checkbox"/> No Line size (bore)-
Pigging	Not required	Required, specify: Round trip pigging Through tree piping Outboard of tree
Insulation	Not required Insulation covering Fluid circulation Electric heating	Check all that apply: Tree connector Tree body Tree flowloops/piping Choke body
Insulation latent heat retention	Insulation design basis (see API 17U)	Cool down from <input type="text"/> °F (°C) to <input type="text"/> °F (°C) Minimum "no touch time" at least <input type="text"/> hours

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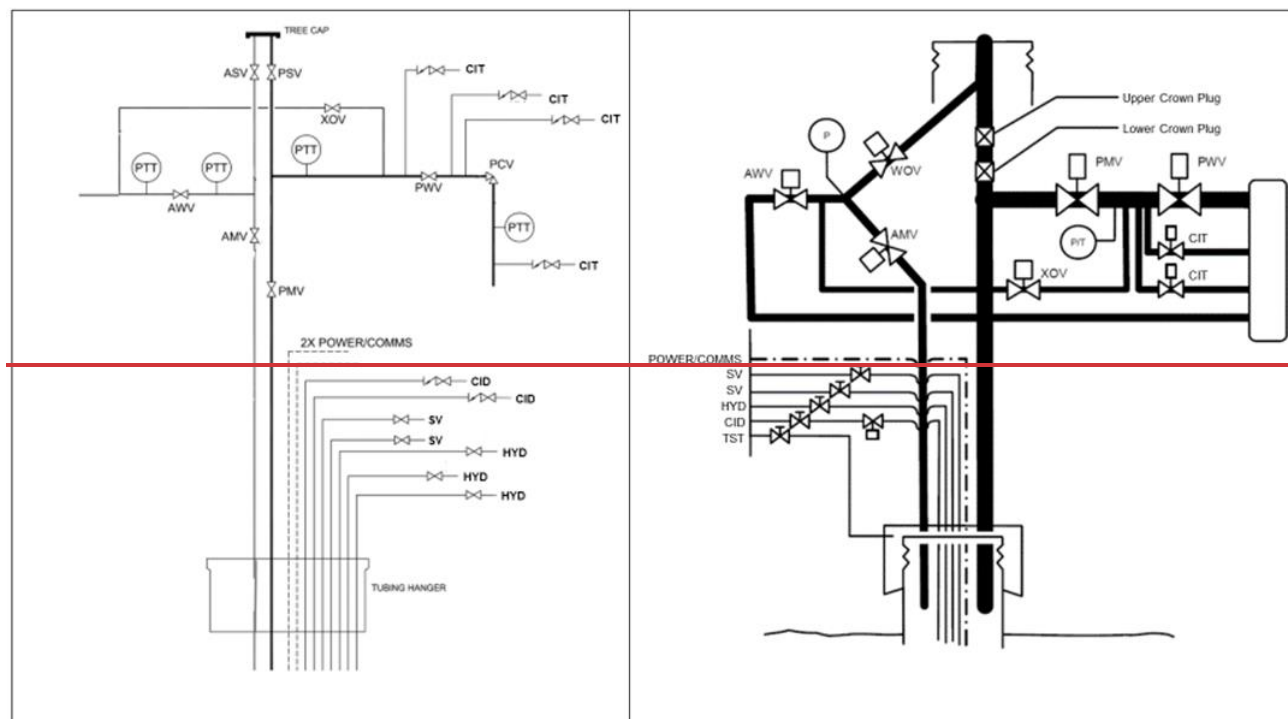


Figure B.2—Examples of Subsea Tree P&ID

(informative)

Alternate Requirements for Carbon and Low-alloy Steel Subsea Forgings

Scope

~~When required by the manufacturer or the user/purchaser, the requirements of DNV-RP-0034 shall supersede all raw material requirements of API 17D.~~

~~This annex contains guidance for additional levels of raw material performance, SFC 1, SFC 2, or SFC 3, above what is prescribed for PSL 3 subsea pressure-containing or pressure-controlling forged components in this specification. SFCs are not applicable to forgings that weigh less than 500 pounds when heat treated, regardless of equivalent round (ER). This annex shall be used in conjunction with DNV-RP-0034 for carbon steel (CS) and low-alloy steel (LAS) grades.~~

~~CS or LAS grades over 95 ksi (655 MPa) specified minimum yield strength may be produced in accordance with DNV-RP-0034, but the Charpy impact requirements should be agreed between the manufacturer and the user/purchaser.~~

C.2 Selection of Steel Forging Classes

~~Subsea components listed in Table C.1 should be SFC 2. SFCs shall be assigned using the following guidance.~~

~~Forgings for pressure-controlling components over 1000 pounds or over 5 in. ER, excluding gates and seats, shall be assigned SFC 1. Forgings weighing 1000 pounds or less and having a 5 in. or less ER shall as a minimum be manufactured according to API 17D/API 6A requirements.~~

~~Forgings for pressure-containing components over 1000 pounds or over 5 in. ER shall be assigned SFC 2. Forgings weighing 1000 pounds or less and having a 5 in. or less ER shall as a minimum be manufactured according to API 17D/API 6A requirements.~~

~~SFC 3 is intended for fatigue sensitive pressure-containing components.~~

~~NOTE ER method pertains to the method described in API 6A 6.4.~~

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Table C.1—SFC 2 Subsea Components

Tubing head assembly—body
Tubing head wing block(s)—body
Valve bonnets (> 1000 lb or > 5 in. ER)
Master valve block—body
Tubing head assembly—connector body
Tree connector—body
Production wing block(s)—body
Annulus wing block(s)—body
Production choke—body
Flowline connector—body
Tubing hanger—body
Tree cap connector—body
Tree running tool—connector body
Subsea wellhead—conductor (low-pressure) housing
Subsea wellhead—subsea wellhead (high-pressure) housing
Transition joint [between subsea wellhead (high-pressure) housing and surface pipe]
Casing hangers—all bodies

~~(informative)~~

~~High pressure High temperature~~

~~Scope~~

~~General~~

~~This annex specifies requirements for load identification, design verification, materials, design validation, and quality of subsea wellhead and production equipment that meet the definition of HPHT, defined here as any environment above 15,000 psi (103.5 MPa) working pressure and/or operating above 350 °F (177 °C). This annex shall be used in conjunction with API 17TR8, whose guidance is limited to pressure-containing components, seals, and fastener components that come into contact with or are immediately adjacent to wellbore fluids operating in HPHT conditions. These requirements may be applied to pressure-controlling components if the design methodology can appropriately assess the applicable failure modes.~~

~~This annex provides additional requirements for HPHT equipment in the following areas of the verification and validation process:~~

~~load descriptions;~~

~~functional specifications;~~

~~risk analysis;~~

~~design verification;~~

~~material selection, characterization, and qualification;~~

~~design validation;~~

~~quality assurance/quality control (QA/QC) and PSLs.~~

~~Equipment repair, other than bolt hole repair, and remanufacturing are not in the scope of this annex.~~

~~Standard Pressure Ratings~~

~~Equipment, except actuators, should be designed to operate at only the standard RWP's identified in Table D.1. The RWP shall be the basis for all testing.~~

~~Temperature Ratings~~

~~Equipment covered by this specification shall be designed and rated to operate throughout a temperature range defined by the manufacturer and as a system. For HPHT service conditions, the temperature class range shall be marked with the standard temperature class designation per 5.1.2.3.1, plus the numerical value of the maximum rated operating temperature, plus the letter "F" for Fahrenheit or "C" for Celsius.~~

~~EXAMPLE — VX400F represents 35 °F to 400 °F temperature range. X450F represents 0 °F to 450 °F. X210C represents -18 °C to 210 °C.~~

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Table D.1—HPHT Equipment Standard Pressure Rating

Equipment	Pressure Rating ≥ 20,000 psi (≥ 138.0 MPa) in 5000 psi (34.5 MPa) increments
Valves, chokes	X
Pressure-containing equipment	X
Pressure-controlling equipment	X
Flanges, connectors (tubing head, tree, tree-running tool), OECs	X
Tubing hangers ^{a,c}	X
Tubing hanger conduits, tree penetrations, and connections ^{a,b}	X
Wellhead (high-pressure) housing and annulus seal assembly	X
Conductor (low-pressure) housing, mudline, and submudline housings, casing hangers submudline annulus seal assemblies ^c	NA
Hydraulic components	PMR
Other ^d	PMR
<p>^a May contain other (nonwellbore) flow passages that shall not exceed 1.0 times the RWP of the tubing hanger assembly plus 2500 psi (17.2 MPa).</p> <p>^b Intermediate pressure rating permitted if component has a higher than working pressure design requirement.</p> <p>^c Rated for working pressure in accordance with the design methods given in this annex or end connection thread, bulkhead fitting requirements.</p> <p>^d Not listed in this table, such as such as running, retrieval and test tools, lockdown bushings, piping.</p>	

Functional Specifications

The manufacturer and user/purchaser shall agree on the equipment functional specifications based on the full life cycle approach.

Functional specifications shall define applicable environmental conditions (including well fluid properties or compositions), operational loads, and cyclic/life cycle load.

Operational cyclic/life cycle loads shall include, as applicable, the following:

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~~combined cyclic loads (bending, tension, shear, etc.);~~

~~test loads that each specific piece will be subjected to during its life cycle;~~

~~extreme and survival events;~~

~~operational pressure/temperature cycles;~~

~~flow-induced loads.~~

~~NOTE—Further guidance on loading conditions for HPHT applications can be found in API 17TR8.~~

~~Where functional requirements are not available, the manufacturer may provide a design technical specification for the equipment based on experience or documented capabilities of existing equipment for review and acceptance by the user/purchaser.~~

~~Load Descriptions~~

~~Load descriptions shall be per API 17TR8, which correlate loads typically experienced on oil and gas equipment to loads identified in ASME BPVC Section VIII, Division 2 and Division 3.~~

~~The loading conditions may be a generalized set of load capacities (capacity chart) defined by the manufacturer based on material strength(s) and various combinations of loads. Alternatively, specific loading conditions may be defined by the user/purchaser to correspond with a certain set of environment and operating conditions.~~

~~The loading conditions as defined shall be categorized as Normal, Extreme, and Survival, as per API 17TR8.~~

~~The RWP shall not be increased above the nominal RWP of the equipment for Normal, Extreme, and Survival load cases.~~

~~Risk Analysis~~

~~A risk assessment (e.g. FMEA, FMECA, HAZID/HAZOPs, etc.) shall be performed on 17D HPHT equipment to identify potential failure modes when this equipment is subjected to the loads identified in the functional specifications. The risk assessment serves as an integral part of defining the verification, material selection/qualification, validation, and quality requirements for mitigating the identified risks.~~

~~The risk assessment shall define the equipment performance (validation) requirements (PR), which are mentioned in D.7. Further guidance on the FMECA process can be found in API 17TR8.~~

~~Design Verification~~

~~General~~

~~Design verification shall be performed to verify conformance to:~~

~~HPHT equipment functional specification;~~

~~serviceability criteria, i.e. API 17TR8;~~

~~acceptance criteria for failure modes typically identified for HPHT equipment:—~~

~~global plastic collapse;~~

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~~local strain limit damage (local failure due to excessive strain);~~

~~ratcheting effects;~~

~~plastic collapse under the hydrostatic test condition;~~

~~fatigue assessment (life cycle estimation).~~

~~Other failure modes may be derived from the risk assessment.~~

~~The requirements of D.5 do not apply to seal design.~~

Design Analysis Methodology

General

~~Design analysis shall be performed according to D.5.2.2 or D.5.2.3. See API 17TR8 for suggested application of design analysis path. When selecting a verification route per API 17TR8 for a component, the code selected should remain constant for all verification assessments.~~

~~The applicable equivalent stress, von Mises equivalent stress (VME) or stress intensity (SINT), should be in accordance with API 6X.~~

~~A system may be made up of components that are verified using different design codes.~~

Linear elastic Analysis

~~Linear elastic analysis shall be used in accordance with ASME BPVC Section VIII, Division 2 or API 6X to verify adequate protection against failure modes identified in D.5.1.~~

~~The allowable stress criteria shall be: $S = 2/3 \times S_{YS,T}$, $S_{PL} = S_{YS,T}$, and $S_{PS} = 2 S_{YS,T}$, where $S_{YS,T}$ = material yield strength adjusted for elevated temperature; S_{PL} is the allowable limit on local primary membrane and local primary membrane plus bending stress; S_{PS} is the allowable primary plus secondary stress at the elevated temperature.~~

~~NOTE 1 — See API 17TR8 for linear elastic analysis of identified failure modes (e.g. global plastic collapse, local strain limit, ratcheting effects, plastic collapse under hydrostatic test condition).~~

~~NOTE 2 — See API 17TR8 for additional information on linear elastic analysis.~~

Elastic-plastic Analysis

~~Elastic-plastic analysis shall be used in accordance with ASME BPVC Section VIII, Division 2 or Division 3 to verify adequate protection against failure modes identified in D.5.1.~~

~~Material characterization for elastic-plastic analysis shall follow D.6.2.1.~~

~~NOTE 1 — See API 17TR8 for elastic-plastic analysis of identified failure modes (e.g. global plastic collapse, local strain limit, ratcheting effects, plastic collapse under hydrostatic test condition).~~

~~NOTE 2 — Elastic-perfectly plastic or limit-load design analyses are acceptable methods provided their results meet the acceptance criteria of the selected method.~~

Fatigue Assessment

General

~~HPHT equipment shall be assessed for fatigue, unless found exempt through fatigue screening.~~

~~NOTE—See API 17TR8 for fatigue screening information~~

Fatigue Design

~~When fatigue assessment identifies components susceptible to fatigue damage, a fatigue design analysis shall be performed by the S-N method (stress or strain based) or fracture mechanics method (FM) addressing the environmental effects on the material of construction. Fatigue assessment method shall be determined by API 17TR8.~~

Fatigue Design Acceptance Criteria

~~The fatigue life cycle assessment shall meet the following.~~

~~S-N design—Fatigue life design margin shall conform to API 17TR8.~~

~~Fracture mechanics design—Fatigue life design margin shall conform to API 17TR8.~~

~~The minimum detectable initial flaw size capability from the manufacturer's NDE procedures (see D.8.5) should be referenced in the design verification calculations.~~

Materials Selection, Characterization, and Qualification

Materials Selection

General

~~Materials intended for pressure containing, pressure controlling, or load bearing API 17D components subjected to HPHT conditions shall follow one of the following:~~

~~API 6ACRA;~~

~~DNV-RP-0034 for carbon steel and low alloy steel;~~

~~API 6A along with API 6MET and API 17TR8 for other grades.~~

~~NOTE—A common list of environmental conditions for HPHT equipment can be found in API 17TR8.~~

Bolting and Seals

~~All closure bolting for HPHT applications shall be manufactured to API 20E or 20F, BSL 3. For all other bolting, Table 4 applies.~~

~~NOTE—See API 17TR8 for additional requirements for HPHT bolting and seals.~~

Materials Characterization

Properties for Design Verification

~~Material properties for linear elastic analysis shall be per API 17TR8. Material properties for elastic-plastic analysis shall be per API 17TR8.~~

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Properties for Fatigue Assessment

~~Before a full-scale fatigue testing program is established, material susceptibility to environmental assisted cracking (EAC) for the intended service condition environment(s) shall be validated using the test protocols found in API 17TR8.~~

Ceramic Material Characterization

~~HPHT equipment utilizing ceramics in conjunction with pressure-containing/pressure-controlling applications shall require proof testing to validate the design RWP as follows:~~

~~six proof tests of three prototypes (2 per prototype);~~

~~for proof tests performed at ambient temperature, the RWP shall be defined as:~~

$$RWP = 0.4W$$

~~for proof tests performed at minimum or maximum rated temperatures, the RWP shall be defined as:~~

$$RWP = 0.67W$$

~~W is the maximum test pressure successfully achieved during proof test where the material maintained structural integrity.~~

~~NOTE The design guidelines in API 17TR8 are based on the premise that ductile materials with good fracture toughness are used in the construction of HPHT equipment.~~

~~Ceramic materials may be needed in certain applications, such as bulkhead penetrations. Ceramics exhibit very low ductility, and it may be difficult to model or analyze structural integrity and functional performance because of this.~~

Materials Qualification

~~The manufacturer shall prepare and conduct a one-time material process qualification to validate a material's mechanical performance properties. Guidance for test protocols is found in API 17TR8. During material qualification, validation samples shall be taken from the same prolongation or sacrificial forging QTC. The material process qualification shall identify all necessary mechanical performance characterization tests and QA/QC validation along with their acceptance criteria. The material process qualification's validation may involve testing at elevated temperatures and/or various environmental conditions, as specified by the manufacturer, while validation is conducted per the test standard's requirements. Both set of test results (taken from the same QTC) shall establish a documented cross-reference between material performance properties and QA/QC acceptance criteria. Subsequently, the manufacturer shall prepare a material process specification containing the QA/QC acceptance criteria for validation to be performed on production run QTCs. Meeting the acceptance criteria of the material process specification shall infer the material's specified mechanical performance properties have been met.~~

~~Additional mechanical performance characteristics (for different temperatures, environments, etc.) may be added later to an existing qualified material, provided there is a material process qualification prepared for the new set of test protocols along with the same set of QA/QC validation meeting the same acceptance criteria to be taken from the new (single/same) validation QTC.~~

~~Other materials with similar mechanical properties but different chemistry/wrought process criteria may not use or infer the cross-reference.~~

Design Validation

General

~~Design validation shall be performed to ensure that equipment demonstrates the mechanical integrity and functionality/operability for the loads identified in the functional specifications. The validation program shall be based on API 17D, plus any additional performance validation identified from the risk assessment, and may include the following types of elements to address the identified risks:~~

~~validation or qualification of an assembly/component under development;~~

~~validation of design method;~~

~~validation of materials for use in design verification.~~

Validation Pressure Tests

~~Hydrostatic body pressure tests shall be performed at ambient temperature using a liquid as the test medium before the start of any validation pressure test program. Functional pressure test programs should follow test procedures and hold times of API 17D using gas as the test medium at the test temperature(s), per the manufacturer's procedures. Functional pressure tests should not exceed the specified RWP by more than 5 %.~~

Performance Requirement, Level 3 (PR3)

~~Equipment subject to PR3 validation shall be validated per API 17D, 5.1.7 requirements, plus the additional performance validation as identified by the manufacturer's risk assessment.~~

~~An exclusion or reduction in the additional performance validation process is acceptable with technical justification, where:-~~

~~performance characteristics have been determined by analysis and validated by similar or scaled testing, with supporting evidence/experience that shall include similar internal or externally published data; or~~

~~quantitative failure assessments may be performed to justify a reduction in the scope of qualification activities, where the failure probability is determined to be below a certain acceptance level agreed with the user/purchaser and/or specified in a recognized code or standard.~~

Performance Requirement, Level 4 (PR4)

~~If fatigue assessment/design is indicated for a component, that component shall require a minimum performance rating of PR4, which includes defining cyclic loading requirements. Validation for fatigue sensitive components shall be per one of the following methods:~~

~~strain-gauging program of a representative test specimen or component, and subsequent comparison analysis of the strain-gauging measurements to the numerical (FEA) results (see API 17TR8); acceptance criteria used for this comparison shall be documented;~~

~~component fatigue testing to demonstrate that the component's fatigue life meets or exceeds required service life; appropriate adjustment (reduced life) for environmental effects (e.g. "knock down" factors or methods) should be applied to correlate the test environment to the service environment.~~

~~PR4 testing may be performed on a separate test article than which was used for API 17D or PR3 validation.~~

Quality Assurance and Product Specification Level

General

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~~PSL 4S for HPHT equipment within the scope of API 17D shall conform to API 6A PSL 4 product standards with the following additions, modifications, or exceptions as outlined in D.8.2 through D.8.6.~~

~~PSL 4S equipment shall be marked with a unique identifier (serial number).~~

Pressure Testing

General

~~Hydrostatic body pressure tests of HPHT components during FAT shall follow API 17D PSL 3 for hydrostatic pressure test procedures and hold times. Functional pressure tests of HPHT components during FAT that contain or incorporate pressure-controlling parts [requiring low or rated working (differential) pressure tests] shall follow API 17D PSL 3G for pressure test procedures and hold times.~~

~~Painting may be performed prior to FAT provided it does not adversely affect the selected NDE method.~~

~~Body pressure testing at hydrostatic test pressures using gas as a test medium is not permitted. Only liquid test mediums are permitted at hydrostatic test pressures at ambient temperature.~~

Hydrostatic Body Test Pressure

~~For $RWP < 20,000$ psi (< 138.0 MPa), the hydrostatic body test pressure during FAT shall be a minimum of 1.5 times the equipment RWP as marked on the component. Hydrostatic body pressure tests during FAT shall be performed at ambient temperature.~~

~~For $RWP \geq 20,000$ psi (≥ 138.0 MPa), the hydrostatic body test pressure during FAT shall be a minimum of 1.25 times the equipment RWP. If linear elastic design methods are used in design verification, then the hydrostatic body test pressure during FAT shall be a minimum of 1.5 times RWP.~~

~~Acoustic emission, if used, should be performed in accordance with procedures specified in ASTM E569 to identify potential flaws, and the acceptance criteria should be agreed upon by the equipment manufacturer and the user/purchaser. The acoustic emission examination should be conducted throughout the duration of the hydrostatic body test.~~

~~Painting may be performed prior to hydrostatic pressure test provided it does not adversely affect the selected NDE method.~~

Test Pressure for Pressure-controlling Components

~~Functional pressure tests for HPHT equipment should follow PSL 3G procedures and hold times of API 17D, using gas as the test medium that will remain in the gas phase at functional test pressure. Functional pressure tests during FAT shall be performed at ambient temperature. Chart recording of pressure tests is required. Functional pressure tests during FAT should not exceed the specified RWP by more than 5 %.~~

~~Backseat testing of valve and choke stems (with or without actuators/operators) is not required.~~

Impact Testing

~~Charpy impact (CVN) shall be in accordance with API 17TR8. Material mechanical properties shall meet or exceed established acceptance criteria values at the assigned coupon testing temperature. Acceptable impact energy values shall also infer that the material's fracture toughness performance at elevated temperatures.~~

~~One set of three Charpy impact (CVN) specimens shall be in accordance with API 17TR8. Material mechanical properties should meet or exceed established acceptance criteria values at the assigned~~

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~~coupon testing temperature. Acceptable impact energy values shall also infer that the material's fracture toughness performance at elevated temperatures is met.~~

~~The CVN test temperature should correspond to one of the temperature classes specified in API 17D, e.g. X (0 °F/-18 °C) or V (35 °F/2 °C).~~

~~Minimum recommended CVN absorbed energy requirements are listed in Table D.2.~~

Table D.2— Minimum CVN Absorbed Energy in Longitudinal and Transverse Direction

Specified Minimum Yield Strength	Average	Single
Up to 75 ksi (517 MPa)	37 ft-lb (50 J) ^a	28 ft-lb (38 J) ^a
Over 75 ksi (517 MPa) Up to 85 ksi (586 MPa)	44 ft-lb (60 J)	33 ft-lb (45 J)
Over 85 ksi (586 MPa)	52 ft-lb (70 J)	39 ft-lb (53 J)
^a ——— For compliance with requirements in API 17G, the minimum absorbed energy in longitudinal direction shall be 44 ft-lb (60 J) average and 33 ft-lb (45 J) single.		

Alternate Material Selection

~~The user/purchaser may elect to specify alternative material performance, processing, or compositional requirements for carbon steel and low-alloy steel forgings per Annex C, which may exceed requirements in this annex.~~

NDE

~~The manufacturer shall define and qualify the NDE methods, probability of detection, size of flaws, its geometry orientation, and location. This may require multiple NDE methods to complete the evaluation and set the acceptance criteria. Each of these parameters shall be defined by the equipment designer as a part of the technical specification required for cyclic fatigue crack growth evaluation.~~

~~The manufacturer shall document the capability of their NDE methods to detect the minimum initial flaw size used in design verification fatigue assessments. Guidance for initial flaw size characterization is found in API 17TR8. NDE methods defined in ASME BPVC Section VIII, Division 2 or Division 3 should be used, according to the selected design methodology and defined by the manufacturer's initial flaw size.~~

~~Magnetic particle (MT) and ultrasonic testing (UT) NDE processes, methods, and procedures shall cover the entire volume.~~

Bolt Hole Repair

~~Weld repair of bolt holes, tapped holes, and machined blind holes used for closure or lifting bolting shall not be permitted. The use of threaded inserts with matching base material requirements to repair bolt holes, tapped holes, and machined blind holes is permitted. The manufacturer shall be responsible for design verification and validation of the thread insert repair.~~

(normative)

Mudline Suspension and Conversion Systems

General

Mudline suspension equipment is used to suspend casing weight at or near to the mudline, to provide pressure control, and to provide annulus access to the surface wellhead. Mudline equipment is used when drilling with a bottom-supported rig or platform and provides for drilling, abandonment, platform tieback completion, and subsea completion. During drilling/workover operations, the BOP is located at the surface. The casing annuli are not sealed at the mudline suspension; therefore, it is necessary to install mudline conversion equipment prior to installing a tubing completion and subsea tree.

Tieback adapters, mudline conversion equipment, and tubing heads are used to provide a preparation to accept the tubing hanger and a profile to which a subsea tree can be locked and sealed.

Major items of equipment used with mudline equipment are:

landing and elevation ring;

casing hangers;

casing hanger running tools and tieback adapters;

abandonment caps;

mudline conversion equipment;

mudline conversion tubing head.

Figure E.1 illustrates the items of equipment used in mudline suspension and conversion equipment.

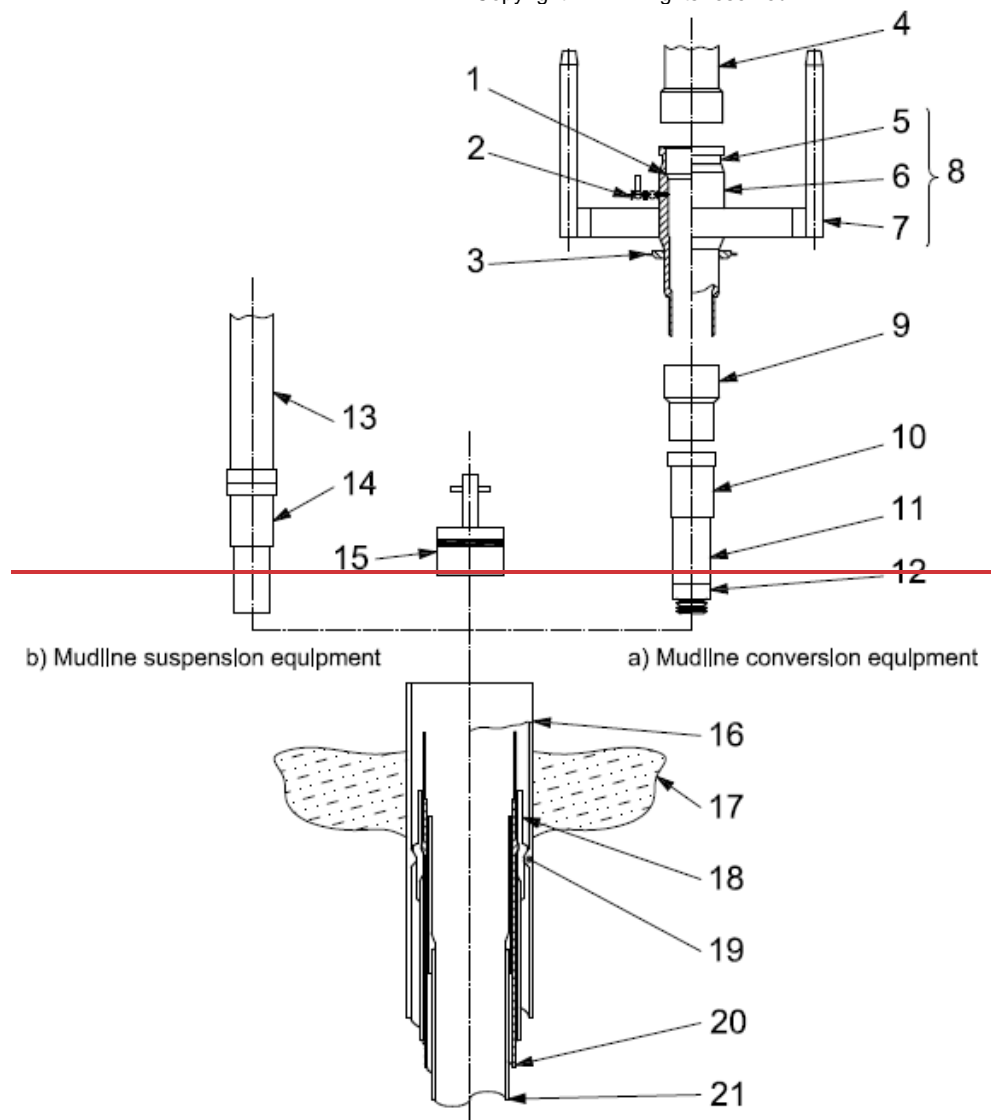
Calculation of Pressure Ratings for Mudline Suspension Equipment

Introduction

The purpose of this annex is to define methods for calculating RWP and test pressure for mudline equipment that are consistent with accepted engineering practice. Mudline equipment design is a unique combination of tubular goods and hanger equipment, and, therefore, it is not intended that these methods and allowable stresses be applied to any other type of equipment. Fatigue analysis, thermal expansion effects, and allowable values for localized bearing stress are beyond the scope of these RWP calculations.

As an alternative to the method presented in this annex, the designer may use the rules in ASME BPVC Section VIII, Division 2 modified in accordance with API 6X in which bending stresses in wall-section discontinuities can be treated as secondary stresses.

When using the alternative method, the calculation for the RWP shall be made in combination with loads applied by the rated running capacity (if applicable) and the rated hanging capacity as well as thermal loads. The designer shall ensure that strains resulting from these higher allowable stresses do not impair the function of the component, particularly in seal areas.



Key

- | | |
|--|---|
| 1 — tubing hanger profile | 12 — tieback tool (tieback-sub) |
| 2 — annulus outlet | 13 — casing riser (to jack-up) |
| 3 — structural support ring (optional) | 14 — casing hanger running tools (landing subs) or tieback tools (tieback subs) |
| 4 — workover completion riser | 15 — abandonment cap |
| 5 — connector profile | 16 — 30 in. (762 mm) conductor casing |
| 6 — wellhead adapter | 17 — mudline |

- 7

PGB
- 8

tubing heads
- 9

annulus seal assembly
- 10

tieback adapter
- 11

casing
- 18

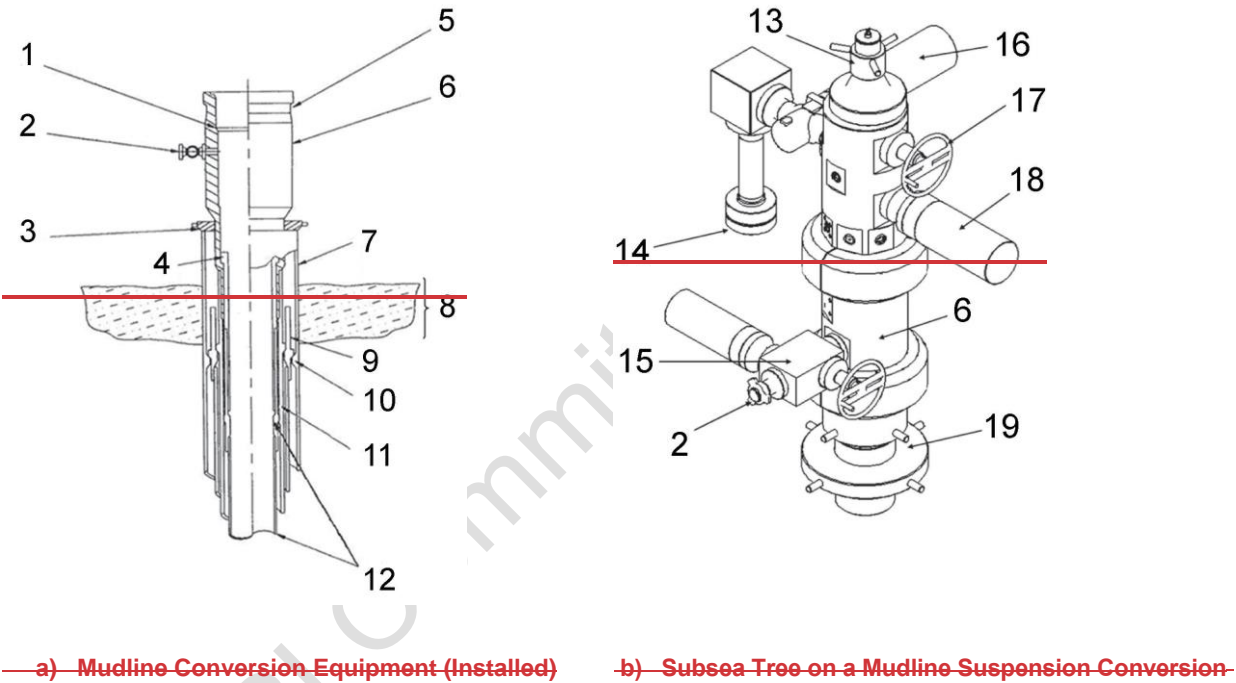
20 in. (508 mm) casing hanger
- 19

30 in. (762 mm) landing ring
- 20

13³/₈ in. (340 mm) casing hanger
- 21

9⁵/₈ in. (245 mm) casing hanger

Figure E.1—Mudline Suspension (Wellhead) and Conversion Equipment



Key

- 1

tubing hanger profile
- 2

annulus outlet
- 3

structural support ring (optional)
- 4

casing hanger tieback adapter
- 5

connector profile
- 11

mudline casing hanger, 13³/₈ in. (340 mm)
- 12

mudline casing hanger, 9⁵/₈ in. (245 mm)
- 13

tree cap
- 14

production outlet
- 15

annulus valves

6 — tubing head	16 — wing valve
7 — conductor casing, 30 in. (762 mm)	17 — swab valve
8 — mudline	18 — master valve
9 — mudline casing hanger, 20 in. (508 mm)	19 — mudline conversion
10 — mudline landing ring, 30 in. (762 mm)	

Figure E.2—Mudline Conversion Equipment

Determination of Applied Loads

The most highly stressed region in each component when subjected to the worst case combination of internal pressure and pressure end load shall be established.

In performing this assessment, bending and axial loads other than those induced by the pressure end caps and threaded end connections required for imposition of pressure end load may be ignored. Specifically, axial or bending loads caused by connection of the component to other equipment are not required in this assessment.

Loads applied through any casing threads that are machined into the component shall be included. The presence of threads cut into the wall of a component and the pressure end loads imparted to the main body of the component through these threads results in local bending stress that shall be included.

NOTE The general shape of the main body of the component can result in section bending stress, especially when pressure end load is added.

Determination of Stresses

After the location of the highest stress for any given component and loading condition have been determined, the stress distribution across the critical section shall be linearized to establish the membrane stress, S_m , the local bending stress, S_b , and peak stress, F , in the section; see Figure E.3 (see API 16Q). The linearization operation shall be performed on each component of stress. The individual linearized components shall then be used to calculate a von Mises equivalent stress through the cross section. The von Mises equivalent stress or distortion energy stress, S_e , shall be calculated as given in Equation (E.1):

$$S_e = \left[S_x^2 + S_y^2 + S_z^2 - S_x S_y - S_x S_z - S_y S_z + 3(S_{xy}^2 + S_{xz}^2 + S_{yz}^2) \right]^{1/2} \quad (E.1)$$

where

S_x, S_y, S_z are the component normal stresses at a point;

S_{xy}, S_{xz}, S_{yz} are the component shear stresses at a point;

subscripts x, y, and z refer to the orthogonal coordinate system.

The linearization operation can be done by hand calculation, but it is more often done using a computer program. If a computer program or FEA post-processing program is used, caution shall be used to verify that the program is calculating the linearization stresses correctly. A check on computer output is highly

~~recommended. One such simple check for FEA post-processing programs is to construct an FEA model of a simple beam in four point bending. This model should be analyzed for plane strain conditions and should have a beam depth made up of at least five elements. The linearized von Mises stress through the center section of such a beam should produce no von Mises membrane stress.~~

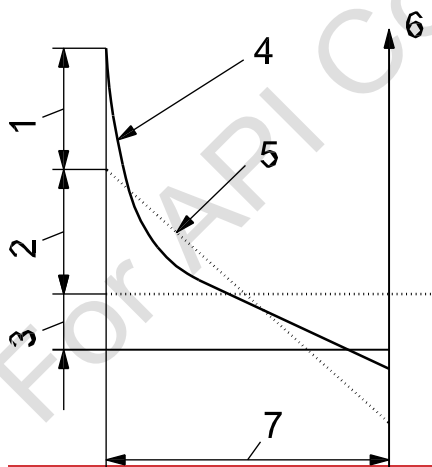
~~The von Mises stress values of interest in the cross section of the component being studied are the linearized membrane (net section) stress, and the linearized local bending stress as shown in Figure E.3. These values consider the multiaxial stress condition at a point since they are von Mises equivalent stresses.~~

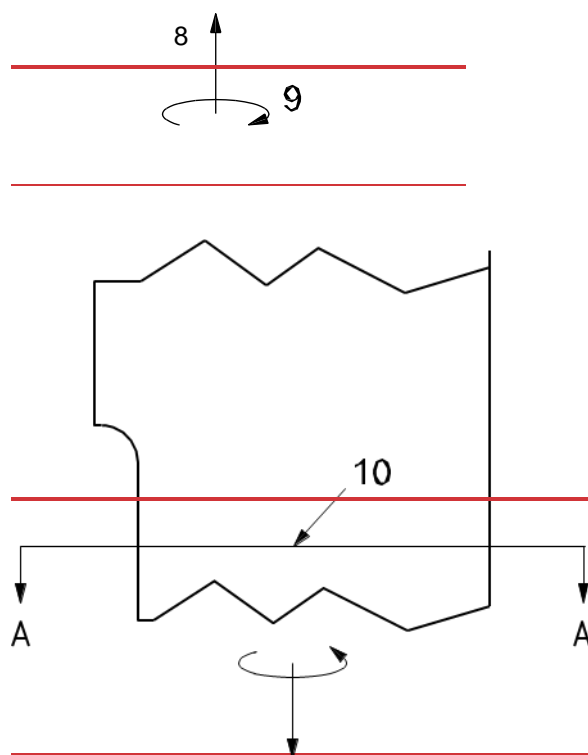
~~Allowable Stress Levels for Working and Test Conditions~~

~~NOTE 1 — The allowable stress levels for test and working conditions are based on percentages of membrane-plus-bending and membrane-only stress required to yield the material. The local membrane and bending stress calculated in E.2.3 are primary stresses since they are the stresses required to provide static equilibrium of the section with the applied pressure and end loads.~~

~~To establish allowable levels for this case, the limiting situation of full section yielding shall be defined.~~

~~NOTE 2 — Assuming the simple case of a rectangular beam and an elastic/perfectly plastic material, a plot of limiting membrane-plus-bending versus membrane-only stress can be made (see ASME BPVC Section II and ASME BPVC Section VIII). Figure E.4 shows the limiting values of various combinations of membrane-plus-bending and membrane-only stresses normalized using the minimum specified material yield strength, S_{MYS} , which is the allowable limit on local primary membrane and local primary membrane-plus-bending stress. The limit stress ratio for membrane only is 1.0, and for bending only, the limit is 1.5. If a membrane stress less than $\frac{2}{3}S_{MYS}$ is added to a large bending stress, the membrane-plus-bending stress ratio may exceed 1.5. This is due to the stiffening effect of the membrane stress and shifting of the beam's neutral axis. This increase in bending capacity when axial load is applied is generally ignored.~~

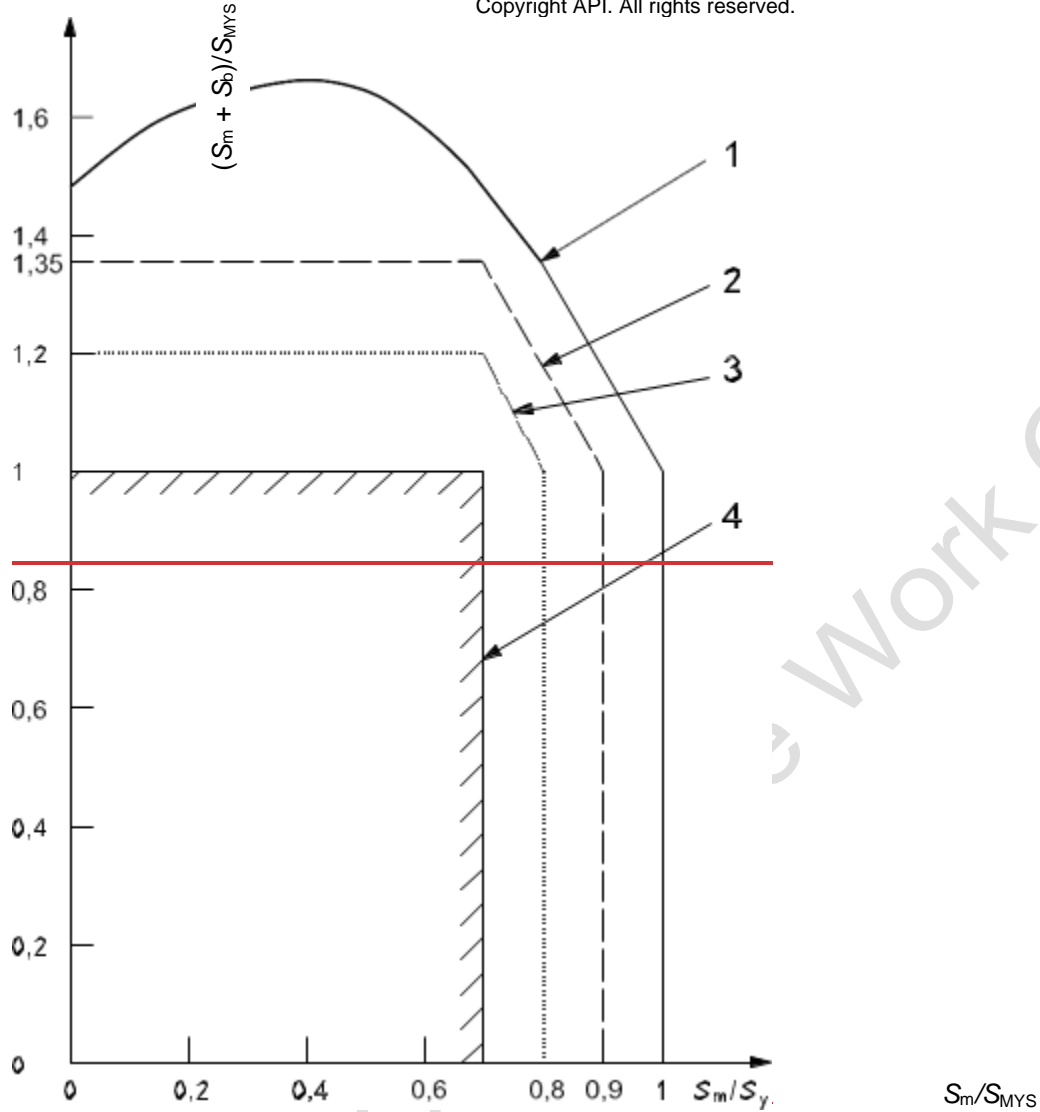




Key-

- | | |
|--------------------------------------|---|
| 1 — local peak stress, F | 6 — stress |
| 2 — local bending stress, S_b | 7 — thickness |
| 3 — net section member stress, S_m | 8 — tensile load |
| 4 — total stress distribution | 9 — local bending moment |
| 5 — equivalent linear distribution | 10 — vertical plane through axisymmetric part |

Figure E.3—Stress Distribution, Axisymmetric Cross Section, Mudline Suspension Components



Key

S_m — membrane stress

S_b — bending stress

S_y — yield strength

1 — limit stress

2 — test pressure limit

3 — RWP for suspension equipment

4 — RWP for conversion equipment

Figure E.4—Limiting Stress Values, Mudline Suspension Components

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(informative)

Assembly Guidelines of API Bolted Flanged Connections

Scope

General

Successful use of API bolted flanged connections require knowledge of their capabilities and careful assembly. This annex provides the provisions for assembly and bolt make-up for type 6BX integral, welding neck, and blind flanges as defined in API 6A and type 17SS integral, welding neck, and blind flanges as defined in this part of API 17D.

Introduction

An assembly procedure for bolted flanged connections is defined. Its purpose is to ensure structural integrity and control of leak tightness for the API bolted flanged connections.

Recommended Bolting Make-up Tension/Torque

NOTE 1 — API flanges are designed and analyzed based on bolt tension in Equation (F.1) generated by using two bolting material yield strengths: 80 ksi or 105 ksi. These two values represent the minimum and maximum bounds for yield strengths used in calculating bolt tensions for API flange applications.

Flange applications using bolt tensions generated from minimum material yield strengths outside of these bounds should be analyzed as OECs per 7.4. Bolting with minimum yield strengths greater than the maximum specified for an API flange applications (such as Alloy 718 at 120 ksi) may be allowed provided the required bolt tension used in Equation (F.1) is calculated based on 105 ksi material yield strength (not 120 ksi) to maintain API flange design integrity and avoid possible flange overload.

Low-strength connection bolting for flanges as defined in F.1.1, such as ASTM A193/A193M grade B7M and ASTM A320/320M grade L7M, shall be made up using a validated bolt preload method that achieves a tensile make-up stress sufficient to ensure flange face circumferential contact at RWP and normal operating loads, while not exceeding yield under test conditions and under worst-case load conditions. Low-strength bolting is defined as having a material yield strength of 80,000 psi (550 MPa).

NOTE 2 — Bolt load scatter can affect joint performance. Use of alternative make-up methods or bolt designs to limit scatter for critical bolting is advised and to be agreed with the user/purchaser.

Table F.1 provides example torque values for ASTM A193/A193M grades B7 and B16, and ASTM A320/320M grades L7 and L43, and for ASTM A193/A193M grade B7M, and ASTM A320/320M grade 7M bolting material. This table provides calculated torque values based on the material yield strengths listed in paragraphs 1 and 2 of this subsection and a 0.07 friction coefficient.

Some factors that affect the relationship between nut torque and bolt tension stress are:

thread pitch, pitch diameter, and thread form;

surface finish of thread faces and nut bearing surface area;

degree of parallelism of nut bearing area with flange face;

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~~type of lubrication or coating of the threads (the friction factor associated with lubricants or coatings can vary up to 20 %);~~

~~nut bearing surface area.~~

~~It should be recognized that torque applied to a nut is only one of several ways to approximate tension and stress in a fastener. The main requirement is to reach the applied tension stress range listed in this subsection and to achieve gasket seating and hub face circumferential contact. The example torque values listed in Table F.1 are provided only as an informative guide, and manufacturer's torque tables(s) shall be supported by documented validation results.~~

~~Flange bolting torques are calculated as given in a) through e).~~

~~Hexagon size (heavy hex nuts) equals $1.5D + 0.125$ in. ($1.5D + 3.175$ mm), where D is the bolt diameter, expressed in inches (millimeters).~~

~~The flange bolt torque, T , expressed in SI units of newton-meters, is given by Equation (F.1):~~

$$T = \frac{F(P)[(1/N) + \pi(f)(P)(\sec 30^\circ)]}{2 \times 10^3 [\pi(P) - (f)(1/N)(\sec 30^\circ)]} + \frac{(h + D + 3.175)(F)(f)}{4 \times 10^3} \quad (F.1)$$

~~where~~

~~D is the bolt thread major diameter, expressed in millimeters;~~

~~A_s is the effective stress area, expressed in square millimeters, equal to:~~

$$A_s = 0.7854 \left(D - \frac{0.9743}{n} \right)^2 \quad (F.2)$$

~~F is the bolt tension, expressed in newtons, equal to A_s times the bolt stress;~~

~~N, n is the number of threads per millimeter;~~

~~P is the pitch diameter, expressed in millimeters;~~

~~f is the friction factor (dimensionless);~~

~~h is the hexagon size, expressed in millimeters;~~

~~The flange bolt torque, T , expressed in imperial units of foot-pounds, is given by Equation (F.3):~~

$$T = \frac{F(P)[(1/N) + \pi(f)(P)(\sec 30^\circ)]}{2(12) [\pi(P) - (f)(1/N)(\sec 30^\circ)]} + \frac{(h + D + 0.125)(F)(f)}{4(12)} \quad (F.3)$$

~~where~~

~~D is the bolt thread major diameter, expressed in inches;~~

~~A_s is the effective stress area, expressed in square inches, equal to:~~

$$0.7854 \left(D - \frac{0.9743}{n} \right)^2 \quad (F.4)$$

F is the bolt tension, expressed in pounds, equal to A_s times the bolt stress;

N, n is the number of threads per inch;

P is the pitch diameter, expressed in inches;

f is the friction factor (dimensionless);

h is the hexagon size, expressed in inches;

Table F.1—Example Flange Bolt Torques (0.07 Friction Factor) for 67 % Yield Strength Tension

Bolt Size		L7, L43, B7, or gr660 Material				L7M or B7M Material			
		Bolt Tension		Make-up Torque		Bolt Tension		Make-up Torque	
in., TPI	mm	lbf	kN	ft-lb	N-m	lbf	kN	ft-lb	N-m
$\frac{1}{2}$ -13 UNC	12.70	9983	44	47	64	7606	34	36	49
$\frac{5}{8}$ -11 UNC	15.88	15,899	71	91	124	12,114	54	70	94
$\frac{3}{4}$ -10 UNC	19.05	23,529	105	158	214	17,927	80	120	163
$\frac{7}{8}$ -9 UNC	22.23	32,483	144	251	340	24,749	110	191	259
1-8 UN	25.40	42,614	190	373	505	32,468	144	284	385
1 $\frac{1}{8}$ -8 UN	28.58	55,609	247	535	726	42,368	188	408	553
1 $\frac{1}{4}$ -8 UN	31.75	70,330	313	739	1001	53,584	238	563	763
1 $\frac{3}{8}$ -8 UN	34.93	86,777	386	987	1339	66,116	294	752	1020
1 $\frac{1}{2}$ -8 UN	38.10	104,951	467	1286	1744	79,963	356	980	1329
1 $\frac{5}{8}$ -8 UN	41.28	124,852	555	1640	2223	95,126	423	1249	1694
1 $\frac{3}{4}$ -8 UN	44.45	146,480	652	2052	2782	111,604	496	1563	2120
1 $\frac{7}{8}$ -8 UN	47.63	169,834	755	2528	3428	129,397	576	1926	2612
2-8 UN	50.80	194,915	867	3072	4166	148,506	661	2341	3174
2 $\frac{1}{4}$ -8 UN	57.15	250,256	1113	4384	5943	190,671	848	3340	4528
2 $\frac{1}{2}$ -8 UN	63.50	312,505	1390	6022	8165	238,099	1059	4588	6224
2 $\frac{5}{8}$ -8 UN	66.68	346,218 ^a	1540 ^a	6975 ^a	9457 ^a	263,786	1173	5315	7205
2 $\frac{3}{4}$ -8 UN	69.85	381,659 ^a	1697 ^a	8023 ^a	10,878 ^a	290,788	1293	6113	8289

^a Calculation uses 105-ksi yield strength—only applicable for L43 or GR660 when bolt size > 2.5".

Guidelines for Assembly

Introduction

Leak-free bolted flanged connections are the result of many selections/activities having been made/performed within a relatively narrow band of acceptable limits. One of these activities essential to

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~~leak-free performance is the connection assembly process. The provisions outlined in Annex F cover the assembly elements essential for consistent leak-tight performance of API flanged connections. Written procedures, incorporating the features of these provisions, shall be developed for use by the qualified connection assemblers.~~

~~NOTE 1 — There are many ways to assemble an API bolted flanged connection and Annex F is intended to provide provisions to those responsible for preparing bolted flanged connection assembly (make-up) procedures or for qualifying bolted flange connection assembler.~~

~~NOTE 2 — The types of bolt-up tools and load control techniques covered by Annex F are not intended to exclude or limit other tools and techniques that are certified to produce an equivalent or better bolt preload scatter value.~~

~~Examination of "Working" Surfaces~~

~~All flange working surfaces should be cleaned and examined before assembly. A nonabrasive cloth may be used to clean all working surfaces to remove grease, preservation coatings, and dirt. Working surfaces are intended to have metal-to-metal contact during make-up, hence any painting on a flange's working surfaces should be removed. Adherent coatings, such as PTFE or plating, are acceptable on the flange working surfaces. Light oils may be used if galling or fretting is a concern.~~

~~Examine the ring groove surfaces of both connection flanges for appropriate surface finish and for damage to surface finish, such as scratches, nicks, gouges, and burrs. Indications running radially in the outer ring groove (leak path) are of particular concern. Unacceptable scratches and dents in the groove and flange face require re-machining. Correct any radial defect in the groove that exceeds the depth of serrations. The defects may be removed by lightly polishing with a fine abrasive wet or dry paper around the gasket seat circumference. Ensure that the rework area blends in uniformly and avoid local polishing of the defect. Report any questionable imperfections for appropriate disposition.~~

~~A new gasket shall be used whenever a flange is opened and re-made. Check the gasket contact surfaces of both surfaces for any mechanical damage and for surface roughness. Reject damaged or questionable gaskets. Gaskets may be reused for testing purpose. A new gasket shall always be used for final assembly. If required, light oil can be used to lubricate the gasket during seating. Take care that no solid particles are present in the lubricant. Report any questionable results.~~

~~Examine stud and nut threads for deformation and damage, such as rust, corrosion, cracks, and burrs. Previously used bolts should be thoroughly cleaned (such as wire brushing) before being reused. Inspect studs that have been subjected to high-cycle external loading with an appropriate NDE technique. Replace questionable parts.~~

~~Examine nut bearing surfaces of flanged for scores, burrs, galling marks etc. Remove protrusions.~~

~~Alignment of Mating Surfaces~~

~~Flanges should be aligned both axially and rotationally to the design plane within specified tolerances. Any pipe or other connection that affects the alignment should be properly supported. The use of bolt load to achieve flange alignment is not permitted. There should be just sufficient gap to insert the gasket in case of horizontal assembly. The flange faces should be aligned within 0.02 in. per each 7.875 in. (0.5 mm per each 200 mm) measure across any diameter (0.15°), and flange bolt holes should be aligned with 0.12 in. (3 mm) offset (see Figure F.1). Report any questionable misalignment or use of excessive loads to align the flanges.~~

~~Dimensions in US customary units-~~

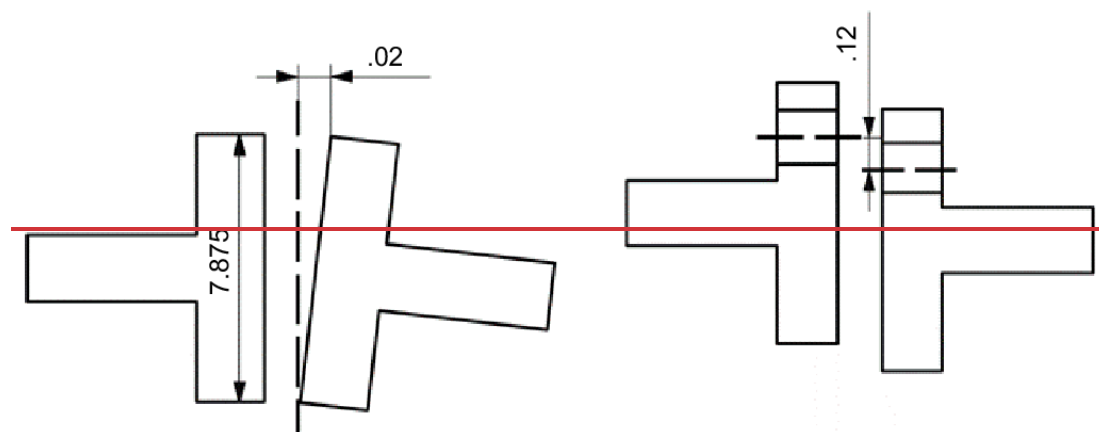


Figure F.1—Flange-to-flange Alignment Tolerances

Installation of BX Gaskets

Check that the BX/SBX gasket complies with specified ring number and material specification.

Position the gasket such that it is concentric with the groove, taking suitable measures to ensure that it is adequately supported during the positioning process.

Ensure that the gasket remains in place during the assembly process. A dab or two of grease may be used to retain the gasket in place when assembling.

NOTE More than two dabs may be required to retain the gasket in place (especially for larger gaskets); but it is important that the majority of the gasket groove is free from grease except for the dabbed locations and that the majority of the gasket is also free from grease (except for dabbed locations). Grease around the full circumference of the gasket or gasket groove or the use of an excessive number of grease dab locations and grease dab size can result in a hydraulic lock condition occurring when making up the joint, which can prevent the gasket from fully seating in the gasket groove, otherwise cause the joint to leak or cause damage to the gasket and/or the gasket groove.

Installation of Bolts

Verify compliance with bolt and nut specifications for the following: material grades, coating, diameter, length of bolts, and nut thickness equal to the bolt diameter (heavy hex series nut).

The nut thread and nut-bearing surface should be lubricated in accordance to the qualified procedure when torque tools are used. Ensure that the lubricant is chemically compatible with the bolt/nut materials and the exposed environment. Particular care should be taken to avoid lubricant chemistry that can result in stress corrosion cracking.

The nuts shall engage the threads for the full depth of the nut. Corrosion of excess thread can hinder joint disassembly. A practice that facilitates connection disassembly is to fully engage the nut on one end (with no part of the bolt projecting beyond the nut) so that all excess length is located on the opposite end. The excess threads should not project more than 0.5 in. (13 mm) beyond the nut, unless required for use of hydraulic tensioners. Hydraulic bolt tensioners require excess thread length of about one bolt diameter for engagement of a pull adapter.

Tightening of the Bolts

Calibrated tools shall be used. Use the selected tightening method, tighten the connection using load-increment rounds of 30 %, 60 %, then 100 % of the specified make-up torque value, in addition to using the crisscross tightening sequence pattern as shown in Figure F.2. Do not tighten the connection while it is subject to pressure or mechanical loads.

Check that the flange face gap at the raised face is closed all around the circumference of the connection.

Bolt tension (or torque) should be rechecked after a flange (or bolted clamp) has been subjected to the initial hydrostatic pressure tests (body test or RWP test). In some instances, the bolting can undergo some minor yielding during the test. Retighten the bolts, as necessary, to 100 % of the make-up tension (torque).

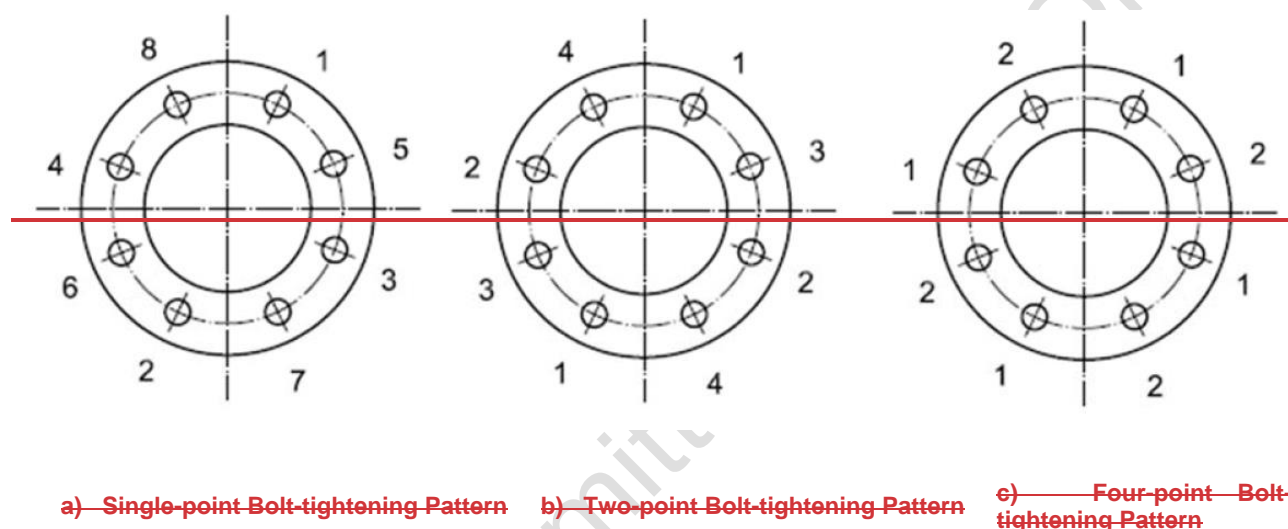


Figure F.2—Cross-bolt Torque Tightening Sequence for One Tool, Two Tools, and Four Tools

Connection Disassembly

Always check, never take for granted, that the connection has been de-pressurized. Ensure that there are no built-in loads in the connection due to restraints. Loosen bolts in the order of a crisscross pattern (see Figure F.2) as follows.

Start with loosening the nuts to 60 % of the target torque in a cross pattern.

Check the gap around the circumference and loosen nuts in the order required to accomplish a reasonably uniform gap.

Loosen the nuts to 30 % of the target torque.

If the gap around the circumference is reasonably uniform, proceed with nut removal on a rotational basis. If the gap around the circumference is not reasonably uniform, make the appropriate adjustments by selective loosening before proceeding with nut removal on a rotational basis.

If flange bolting or nuts are fully loosened, they shall be cleaned, and all accessible surfaces shall be visually examined for damage. If gaskets are reused for testing purpose, marks should be placed on the gaskets to ensure that new gaskets are used for the final assembly.

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~~NOTE 1 — When loosening bolting, the elastic recovery of the clamped parts can result in excessive loads on the unloosened bolts and flange.~~

~~Loosening and re-tightening of flange bolting may result in a different torque to tension relationship and consequently may require an alternative validated torque table.~~

~~NOTE 2 — Refer to API 6AR for flange bolting that has been in service.~~

Records


Manufacturers shall document recommended make-up tension (or torque) as a part of the end connection assembly record for each assembled connection. A typical record is provided in Table F.2.

Table F.2—Flange Connection Make-up Record

BOLTED FLANGE CONNECTION MAKE-UP RECORD					
ASSEMBLY					
Assembled by: _____ Date: _____					
Cleaning and examination of components prior to assembly					
Clean and check that ring groove and BX gasket seating surfaces are free for damage	<input type="checkbox"/>	Clean bolts and nuts and check that they are free from damage	<input type="checkbox"/>		
Clean and check that the nut bearing surface of flanges are free of paint, dirt, and galling marks				<input type="checkbox"/>	
Check applied flange connection components					
Bolt material			Nut material		
Bolt diameter and length			Bolt/nut coating		
Gasket size and material		New BX gasket used for final assembly		<input type="checkbox"/>	
Lubrication of bolt/nut “working surfaces”					
Check that applied lubrication on bolt end threads/nut bearing surface corresponds with the lubrication used for establishing torque tables			<input type="checkbox"/>	Applied lubrication:	
Alignment and installation of bolts					
Studs free to move within bolt holes	Yes <input type="checkbox"/> No <input type="checkbox"/>		Maximum flange face gap in or mm		
Hand tight torque ft.lb or N.m			Minimum flange face gap in or mm		
TIGHTENING OF BOLTS					
Target bolt load		Tool type:		Number of tools:	

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30 %-preload		60 %-preload		100 %-preload	
Torque	Pump-pressure	Torque	Pump-pressure	Torque	Pump-pressure
Face-to-face contact			Torque by: _____ Date: _____		
UNANTICIPATED PROBLEMS AND THEIR SOLUTIONS					
CONTROL		By: _____ Date: _____			
Target-preload:	Torque:	Tool:	Pump-pressure:	Preload-acceptable:	Flange face contact:

For API Committee Work Only

(informative)

Design and Testing of Pad Eyes for Lifting

General

The purpose of this annex is to provide a recommended practice for the design and verification of lifting pad eyes (including pad eye lift subs) used as lifting and handling points for equipment covered in this specification. This annex has been written to provide a single unified set of design calculations intended to meet or exceed pad eye designs proffered by different regional lift codes. However, it is still the responsibility of the designer to compare and verify that pad eye designs from this annex indeed meet or exceed local code requirements.

Assemblies and equipment that are handled between supply boat and rig exceeding 22,500 pounds MGW should feature additional pad eyes for handling (tag lines) or tie down (transportation, sea fastening, etc.). These unmarked (non-red) pad eyes are outside the scope of this annex.

To reduce the likelihood of compounding design margins or load amplification factors, Table G.1 lists enhancement factors for different load ratings. These factors are designed to be simple to use and conservative, incorporating the effects of skew lifting angles, submerged lift hydrodynamic forces, vessel heave, and the “n-1” rule to account for the loss of a sling leg during a lift. Enhancement factors are higher at smaller loads, as they are more unstable and susceptible to dynamic load variations (larger when compared to the static load). Allowable stresses and design margin acceptance criteria in this annex are based on 85 % of material yield strength unless stated otherwise.

Table G.1—Enhancement Factors for Pad Eyes on Subsea Equipment

Weight- (MGW)	Enhancement Factors (<i>EF</i>) ^{1,2}				
	lb	1-Pad Eye	2-Pad Eyes	3-Pad Eyes	4-Pad Eyes
kg					
≤ 2000	≤ 4409	7.50	4.00	3.50	2.50
2500	5512	7.00	4.00	3.00	2.00
3000	6614	6.50	4.00	3.00	2.00
3500	7716	6.00	4.00	3.00	2.00
4000	8818	6.00	4.00	3.00	2.00
4500	9921	5.75	3.50	3.00	2.00
5000	11,023	5.50	3.50	3.00	2.00

5500	42,125	5.50	3.50	3.00	2.00
6000	43,228	5.25	3.50	3.00	2.00
7000–20,000	45,432– 44,092	5.00	3.00	2.00	1.50
21,000– 25,000	46,297– 55,116	5.00	3.00	1.50	1.25
>25,000	>55,116	3.00	2.00	1.50	1.25
¹ —— For intermediate MGW values, the EF may be interpolated. Recommended minimum values for EF take into account design factors for the effects of hydrodynamic drag and added mass for submerged lifts. Consult DNVGL-ST-E273 or DNV-ST-N001 for different EF values for lifts in air. ² —— EF values may be reduced to 5.00, 3.00, 3.00, 2.00, respectively, for all MGW payloads < 14,330 lb (< 6500 kg), if vessel heave kept below 10 ft. (3 m) during a lift.					

This annex does not cover pad eyes used for functions other than lifting. In addition, this annex does not cover the maintenance of reusable lifting devices to which the (subsea hardware) lifting pad-eye is attached. Guidelines for reusable lifting devices (lifting frames and appliances) can be found in 5.5.3.

This annex assumes that shackles are used to interface with the lifting (point) pad eyes, and sling lift angle (see Figure G.3) is 30 degrees from vertical or less, but not to exceed 45 degrees.

Structural framing design that incorporates lifting pad eyes into the overall structure of offshore and subsea structures (such as offshore jackets, offshore decks and platforms, subsea manifolds and templates, subsea mudmats, subsea PLETs and sleds) should be designed to withstand the same design loads as the pad eyes and take into account structural loads from subsea equipment installation (such as buckling due to compressive loads created by slings) and subsequent operation, as discussed in 5.1.3.6.

Design

Pad Eye Materials

Pad-eye plate should be constructed from special or primary steel meeting API 2H minimum or equivalent. Pad-eye lift subs should be constructed from bar stock or round forgings meeting API 6A minimum or equivalent.

NOTE API 2H plate material typically has a S_{MYS} of 42,000 psi (289 MPa) or 47,000–50,000 psi (324–345 MPa); API 6A forged material typically has a S_{MYS} of 60,000 psi (414 MPa) or 75,000 psi (517 MPa).

If the lifting load is transferred through the plate thickness (z-axis) plates with specified (documented) through thickness properties shall be used.

Design Lift Temperature

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~~The design lift temperature should not be greater than the (statistically) lowest daily air temperature for the area where the lift takes place. In the absence of a design temperature designation, the design temperature should be -4°F (-20°C).~~

~~NOTE—Lifts performed in temperatures colder than -4°F (-20°C) are considered outside the scope of this annex.~~

~~Ductility~~

~~Primary members and lift points (pad eyes) of lifting equipment should be manufactured with materials that have sufficient ductility while supporting the load at the temperatures at which the equipment is being lifted. Impact material properties for pad eyes should follow API 2H, API 6A, or DNVGL-ST-E273 requirements for a given planned design lift temperature.~~

~~Corrosion~~

~~If lifting is required after prolonged exposure in aggressive environments or after possible damage to cathodic protection systems, a risk assessment should be performed.~~

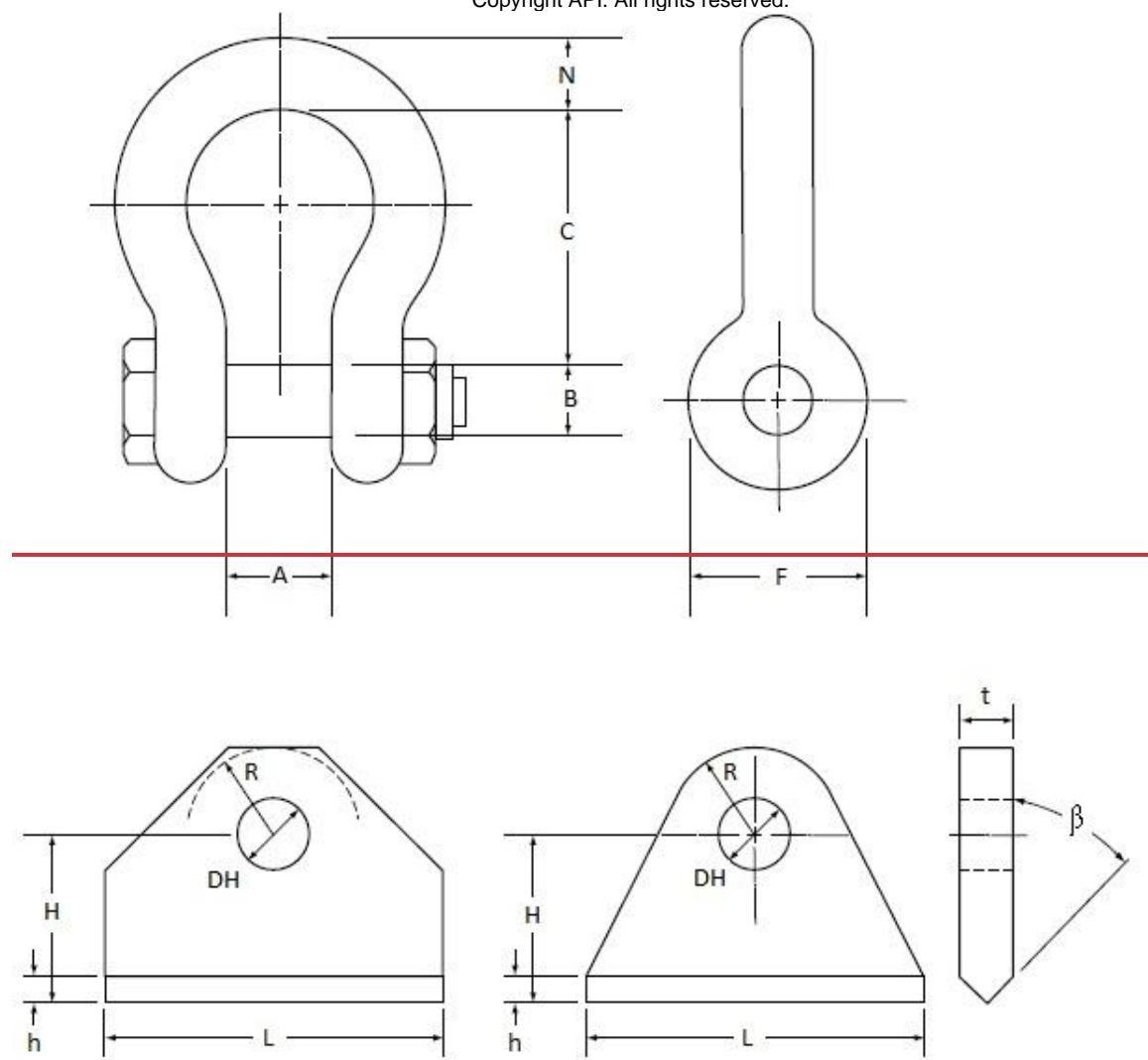
~~Certification and Inspection~~

~~All lifting equipment primary members in the load path and lift points (pad eyes) should require material certification and NDE in accordance with 5.4.4.~~

~~Manufacturing Dimensions~~

~~General~~

~~The basic dimensions of pad eyes are calculated in accordance with design rules below (see Figure G.1) and the overall shape of a lifting shackle. A summary of the design loads and calculated design stresses based on these dimensions is found in G.3.~~



Key

- A — shackle jaw width
- B — shackle bolt diameter
- C — shackle inside length
- N — shackle loop thickness
- F — shackle flange width
- L — pad eye length
- D_H — hole diameter
- R — minimum distance from center of bolt hole to pad eye edge
- t — pad eye thickness

h — pad eye weld thickness, equal to $t/2$ for full penetration welds

H — height from base to center of pad eye hole

β — bevel angle for weld preparation

Figure G.1—Shackle and Pad Eye Profiles and Dimensions (Not to Scale)

Manufacturing tolerances for pad eye geometry should follow dimensioning guidelines as defined in 5.1.4.2.

NOTE For a pad eye thickness larger than 2.0 in. (50.8 mm), see API 6A for recommended weld geometries.

Pad Eye Bolt Hole (D_H)

The pad eye hole diameter shall be selected to fit the shackle pin diameter.

The shackle pin diameter should not be less than 94 % of the pad eye hole diameter.

Pad eye bolt holes should be drilled or machined. Holes flame cut by hand are not acceptable.

Pad Eye Thickness (t)

The pad eye thickness, t , should not be less than 75 % of the shackle jaw width, A , as given by Equation (G.1):

$$t \geq 0.75 \times A \quad (G.1)$$

EXAMPLE If $A = 60.96$ mm (2.40 in.), then $t \geq 0.75 \times 60.96 = 45.72$ (0.75 \times 2.40 = 1.80 in.).

To avoid excessive clearance between the shackle jaws and the pad eye, increasing the pad eye thickness or adding cheek plates are acceptable. Cheek plate thickness should not be used in bearing or tear-out stress calculations. If added strength desired, reduce cheek plate thickness and increase pad eye thickness (t). However, the pad eye thickness should not exceed 90 % of the shackle jaw width, A , to provide adequate clearance for fitting the shackle over the pad eye, as given in Equation (G.2):

$$t \leq 0.90 \times A \quad (G.2)$$

EXAMPLE If $A = 60.96$ mm (2.40 in.), then $t \leq 0.90 \times 60.96 = 54.864$ mm (0.90 \times 2.40 = 2.16 in.).

See G.3.3 for stress calculations with respect to t .

Pad Eye Radius (R)

The pad eye design should allow free movement of the shackle and sling termination without fouling the pad eye. In general, the radius, R , of the pad eye is taken as 1.75 to 2 times the pad eye bolt hole diameter, D_H . See G.3.3.1 for stress calculations with respect to R . A greater value of R ($R \geq 2.0 \times D_H$) may be used to improve the calculated value of the tear-out stress, provided this does not cause a clearance issue for the wire rope with the thimble inside the shackle eye. See G.3.3.3 for tear-out stress calculation.

For lifting sub pad eyes that are machined from bar stock, pad eye length (L) is approximately equal to the shoulder OD of the lifting sub's thread profile.

Distance from Base to Center Line of Pad Eye Bolt Hole (H) and Weld Height (h)

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~~The minimum distance from the base of the pad eye to the centerline of the pad eye bolt hole (H) should be sufficient to ensure that the shackle jaw does not interfere with the weld height (h).~~

~~This is done by adding clearance as shown in Equation (G.3):~~

$$~~H = \left(\frac{F}{2} + h \right) + C \quad (G.3)~~$$

~~where~~

~~C (clearance) is 12.7 mm (0.5 in.) for shackles with $F_p \leq 13,000$ lb (57,827 N);~~

~~C (clearance) is 25.4 mm (1.0 in.) for shackles with $F_p > 13,000$ lb (57,827 N);~~

~~F is the shackle pin flange width as defined in Figure G.1;~~

~~h is the weld height.~~

~~The calculated value of H may be increased for extra shackle or rigging clearance.~~

~~See G.3.3.4 for stress calculations with respect to weld height (h).~~

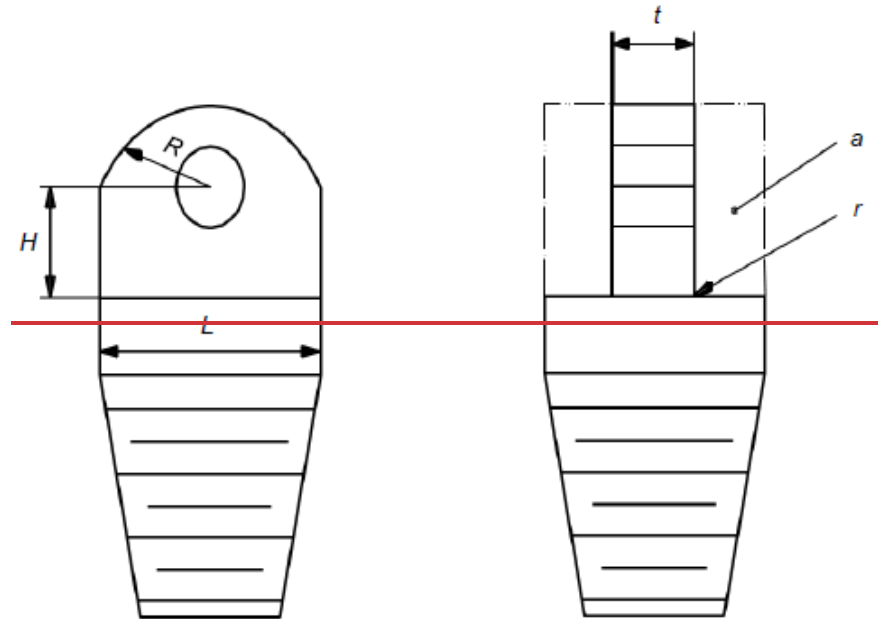
~~For lifting subs that are machined from bar stock (see Figure G.2), H is calculated as given in Equation (G.4):~~

$$~~H = \left(\frac{F}{2} \right) + C \quad (G.4)~~$$

~~where~~

~~C (clearance) is 12.7 mm (0.5 in.) for shackles with $F_p \leq 13,000$ lb (57,827 N);~~

~~C (clearance) is 25.4 mm (1.0 in.) for shackles with $F_p > 13,000$ lb (57,827 N).~~



Key

L — pad-eye length

R — minimum distance from center of bolt hole to pad-eye edge

t — pad-eye thickness

H — height from base to center of pad-eye hole

r — fillet radius (typical both sides)

a — region of material machined away

Figure G.2—Pad Eye Lift Sub Dimensions (Not to Scale)

Pad Eye Length (L)

Recommended minimum value of a pad-eye length, L , given by Equation (G.5) is:

$$L = 2 \times R \quad (G.5)$$

Actual pad-eye length may depend on geometric constraints. For example, a pad-eye with 60-degree tapered sides has a length

$$L = \frac{R}{\cos 30^\circ} + (H - h) \tan 30^\circ$$

NOTE See G.3.3 for weld throat stress calculations.

G.2.3 Other Design Requirements

Other design requirements are as follows.

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~~Pad eyes should not protrude outside the boundaries of the host structure and should, as far as possible, be designed to avoid damage from other equipment.~~

~~Lifting points should be positioned to preclude, as far as possible, the risk of slings fouling against the host structure or its cargo during normal use.~~

~~To prevent lateral bending moments, the pad eyes should be aligned with the sling to the center of lift. In other words, the sling load should be in the plane of the pad eye's plate.~~

~~In some instances, the sling arrangement and its resultant positioning of the pad eye can locate the pad eye along a "weaker" moment-of-inertia plane of the structural member to which the pad eye is affixed. (Structural I beams and H beams are especially susceptible.) It is necessary to pay special attention to locate these weaker orientations and reinforce the structural beam with stiffener webs, plates, doubler saddles, etc., as appropriate.~~

~~In some instances, fillet welded cheek plates are used to fill up the space between the pad eye and the shackle jaw width. The thickness associated with these cheek plates should not be taken into account when calculating the pad eye bearing or tear-out stress.~~

~~To avoid deformation during welding of the structural member to which the pad eye is being affixed [in cases where the pad eye thickness is > 0.25 in. (6.35 mm) greater than the structural member cross sectional thickness], reinforcement such as stiffeners, plates, doubler saddles, etc. may be used, as appropriate.~~

~~Pad eyes should be located such that sufficient access is maintained for NDE of the pad eye welds and load testing (see G.4).~~

~~Pad eyes welded onto the primary structure and/or with cheek plates welded on are subjected to heat affected zones that could locally reduce the yield strength of those materials.~~

~~Design Calculations and Loading Criteria~~

~~General~~

~~Assumptions~~

~~The following may apply:~~

~~Load is lifted by single crane.~~

~~Spreader bars are not used for lifting, although in controlled environments they can be used.~~

~~Equipment is not pressurized during transportation.~~

~~Cheek plate thickness shall not be used for calculating stress.~~

~~For subsea submerged applications, installation/lift will ensure no slack slings.~~

~~Sling Angle~~

~~The sling angle, γ , is defined as depicted in Figure G.3.~~

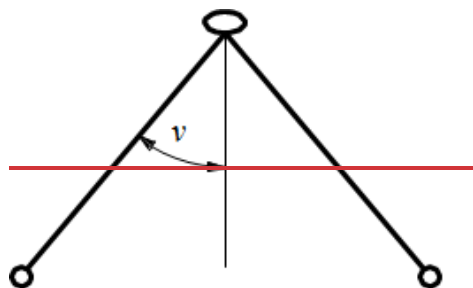


Figure G.3—Pictorial Representation of Lifting Set Showing the Angle of Sling Leg from Vertical

The sling angle from vertical, v , should not exceed 45 degrees.

Pad-Eye Design

To prevent equipment lifts from overturning (tipping) on a moving deck, pad eyes should be located to withstand the following tilt angles in any direction without overturning as follows:

for vessel heave of 10 feet (3 meters): 15 degrees;

for vessel heave of 20 feet (6 meters): 30 degrees.

Design stresses for lift points should not exceed 85 % of the specified yield strength of the pad eye material at the design load, F_P :

Multi-point lift points should be designed so that they can be lifted from $(n - 1)$ legs, where n is the number of lift points. Multipoint lift points should address the effect of the sling-leg angle from vertical in accordance with Figure G.3.

For single pad eyes, the total vertical design load (F_P) is given in Equation (G.6):

$$F_P = EF \times MGW \quad (G.6)$$

where

MGW for permanently installed equipment is the maximum gross weight of the permanently installed equipment. Calculations should also account for any increase from anticipated amount of seawater that could be entrained within the subsea hardware from a subsea lift into the air.

MGW for reusable lifting devices needs to account for the added weight from: lift frames (such as spreader bars and strong-back beams), cargo (such as lifting permanently installed equipment), rigging, plus any additional seawater entrainment from lift frames.

EF is the enhancement factor (see Table G.1), based on MGW , incorporating the $(n - 1)$ leg lifting design practice where n is the number of lift points, including submerged hydrodynamic effects (drag and added mass), and motion effects associated with vessel heave [assumed up to 20 feet (6 meters)].

For multiple pad eyes, the design load, F_P , for each pad eye should be calculated as given in Equation (G.7):

$$F_p = \frac{EF \times MGW}{\cos \nu} \quad (G.7)$$

where

sling angle (ν) from vertical is used for design (see Figure G.3).

The angle from vertical, ν , shall not exceed 45° .

For a sling angle (ν) of 45° , the design load F_p , as given by Equation (G.8), is expressed as:

$$F_p = \frac{EF \times MGW}{\cos 45^\circ} \quad (G.8)$$

Calculation Methodology

Calculated Stress Basis for Pad Eye Dimensions of Plate Thickness (t)

The criteria specified in G.3.3 ensure that the “hot spot” stresses at the bolt hole are below the minimum specified yield strength.

Contact Stress Between the Shackle Bolt and Pad Eye Hole

For larger shackle pin diameters ($B \geq 0.94 \times D_H$), the contact stress is calculated as follows, per Equation (G.9):

$$\sigma_c \geq 0.045 \sqrt{\frac{F_p \times E}{D_H \times t}} \quad (G.9)$$

where

F_p is the resulting sling load on the pad eyes;

E is the elastic modulus of the material;

D_H is the pad eye hole diameter;

t is the thickness of pad eye at hole/material thickness.

For smaller pin diameters ($B < 0.94 \times D_H$), the following Equation (G.10) is used:

$$\sigma_c \geq 0.18 \sqrt{\frac{F_p \times \left(\frac{1}{D_{pin}} - \frac{1}{D_H} \right) \times E}{t}} \quad (G.10)$$

where

allowable stress is $\sigma_e \leq 0.85 \times S_{MYS}$.

Tear-out Stress at Pad Eye Hole

The tear-out stress is calculated by Equation (G.11):

$$\sigma_t \geq \frac{3 \times F_p}{(2 \times R - D_H) \times t} \quad (G.11)$$

where

allowable stress is $\sigma_t \leq 0.85 \times S_{MYS}$

NOTE 1 — Do not include the thickness of cheek spacers when calculating the tear-out stress.

NOTE 2 — The “3” in Equation (G.11) is a stress-concentration factor for the shackle bolt hole and is applicable for both single-point and multi-point lift.

A greater value of R ($R \geq 2.0 \times D_H$) may be used to improve the calculated value of the tear-out stress, provided this does not cause a clearance issue for the wire rope with the thimble inside the shackle eye.

If fillet-welded doubler saddles plates are used, the saddle plate dimensions should be the pad eye length, L , for the minimum length and width, and the pad eye weld height, h , for the minimum saddle plate thickness.

All lift pad eyes and related primary member welds shall be full penetration welds and considered “critical welds” per Section 5. If the pad eye is to be secured to a flat structural surface by fillet welding, Section 5 requires that the pad eye be fabricated with the appropriate bevels (see the example in Figure G.1). See API 6A for weld geometry practices.

If the pad eye is a forged or an integral part of the structure and the load is transferred directly into the structure, then pad eye design calculations should be commensurate with the integral design.

Weld Calculations for Full-penetration Fillet Weld

Shear stress due to the horizontal component of the force at the throat of the weld is found in Equations (G.12) to (G.22). They are based on classical equations for model 45° fillet welds to ensure that the weld is sufficient to withstand shear and bending stresses.

$$S_S = \frac{S_F}{A_w} \quad (G.12)$$

where

S_F — is the shear force acting on pad eye weld = F_p ;

F_p — is the pad eye design load;

ν — is the sling angle, as shown in Figure G.3; or for a single pad eye lift, the maximum skew angle of the sling just before the load is lifted off the ground;

A_w — is the total throat area = $2 \times (0.707 \times h \times (L + t))$;

h — is the weld size (full penetration) = $0.5 \times t$;

~~t is the thickness of the pad eye;~~

~~L is the length of the pad eye.~~

~~The calculation for the shear stress, S_s , can then also be as given in Equation (G.13):~~

~~$$S_s = \frac{F_p \sin \nu}{A_w} \quad (G.13)$$~~

~~The permissible stress for butt or fillet welds in shear is determined using a design margin for the weld in shear of 0.577/0.40, or 1.44 (based on the distortion energy theory as the criterion of failure) as given in Inequality (G.14):~~

~~$$2.5 \leq \frac{S_{MYS}}{S_s} \quad (G.14)$$~~

~~where~~

~~S_{MYS} is the specified minimum yield strength of the pad eye base and weld material.~~

~~Tensile stress due to the vertical component of the force at the throat of the weld, tensile stress, S_t , is calculated as given in Equation (G.15):~~

~~$$S_t = \frac{T_p}{A_w} \quad (G.15)$$~~

~~where~~

~~T_p is the tensile force acting on pad eye weld = $F_p \times \cos \nu$.~~

~~Tensile stress as given by Equation (G.16):~~

~~$$S_t = \frac{F_p \cos \nu}{A_w} \quad (G.16)$$~~

~~Allowable stress for butt welds in tension is $0.6 \times S_{MYS}$, as derived from inequality (G.17):~~

~~$$(S_{MYS} / S_t) \geq 1.67 \quad (G.17)$$~~

~~Bending stress at throat due to the horizontal component of the force — Bending stress, S_b , is calculated as given in Equation (G.18):~~

~~$$S_b = \frac{M_y}{I_w} \quad (G.18)$$~~

~~where~~

M is the bending moment $= F_p \times \sin \nu \times H$;

y is the dimension from neutral axis to end of weld $= (L + 2h)/2$;

I_w is the moment of inertia of weld $= 0.707 h \times I_u$;

I_u is the unit moment of inertia of weld $= \frac{L^2(3+L)}{6}$;

h is the weld size (full penetration) $= 0.5 \times t$.

Design margin as given by inequality (G.19):

$$(S_{MYS}/S_b) \geq 1.52 \quad (G.19)$$

where

S_{MYS} is the specified minimum yield strength of the pad eye base and weld material.

Maximum Shear Stress Theory at Throat

Total direct vertical stress, S_d , is the superposition of the tensile stress, S_t , and bending stress, S_b , as given in Equation (G.20):

$$S_d = S_b + S_t \quad (G.20)$$

The maximum shear stress, τ_{max} , at the weld is as given in Equation (G.21):

$$\tau_{max} = \sqrt{\left(\frac{S_d}{2}\right)^2 + S_s^2} \quad (G.21)$$

where

S_s is the shear stress on the pad eye weld;

S_b is the bending stress on the pad eye weld;

S_t is the tensile stress on the pad eye weld.

The allowable stress for butt or fillet welds in shear is determined using a design margin for the weld in shear of 0.577/0.40, or 1.44 (based on the distortion energy theory as the criterion of failure) as given in Inequality (G.22):

$$2.5 \leq \frac{S_{MYS}}{\tau_{max}} \quad (G.22)$$

where

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~~S_{MYS} —is the specified minimum yield strength of the pad eye base and weld material.~~

Factory Testing of Equipment Lift Points and Primary Load Path Members

General

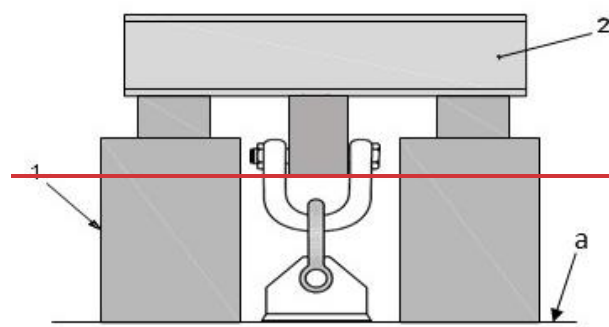
~~Permanently installed equipment (as defined in 5.1.3.6) is lifted during manufacture, transportation, and subsequently installed subsea. This equipment is seldom lifted during its operational life.~~

~~Reusable lifting device (such as tools as defined in 5.1.3.7, lift frames, baskets, or transportation handling equipment) is lifted repeatedly during its operational lifetime.~~

~~Welds on lift pad eyes and primary members in the lifting load path shall follow weld requirements as specified in 5.3.2 and 5.4.3. All lift point and primary member welds in the load path shall be designated as “critical welds.”~~

Testing and Inspection

~~Each welded lift pad eye and its adjacent mounting area shall be individually (vertical) proof load tested to at least two and one-half (2.5) times the individual lift pad eye's MGW. An example of an individual vertical proof load test is shown in Figure G.4.~~



Key

1 — hydraulic or mechanical ram

2 — I beam or structure with pad eye support

a — area around lift pad eye should be designed to provide clearance and structural support for the vertical proof load test

Figure G.4—Localized Testing of Fabricated Pad Eyes

~~The individual pad eye test load of a multi-point lift pad eye should not exceed 2.5 times the individual pad eye's marked load lift capacity. For example, a subsea assembly that has an MGW of 10,000 lb (4536 kg) and designed for a four-part sling lift is marked by each of the four lift pad eyes as: 4 × 2500 lb. Therefore, the pad eye's lift load capacity is 2500 lb, and the vertical proof load should not exceed 2.5 times 2500 lb, or 6250 lb (2835 kg).~~

~~Where practical, the entire equipment assembly should also be load tested (load test by overhead lift through all lift points) to 1 times the MGW to demonstrate sling angle, alignment, and load stability with respect to the equipment's center of gravity. Load testing beyond the equipment's MGW is not required. The MGW is defined in Equation (G.7).~~

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~~Visual examination and magnetic particle examination, or dye (liquid) penetrant, LP shall be performed on the lift pad eye's tear-out region and adjacent welds in the load path after load testing as shown shaded in gray in Figure G.5. This is in addition to any examination of welds at the time of fabrication.~~

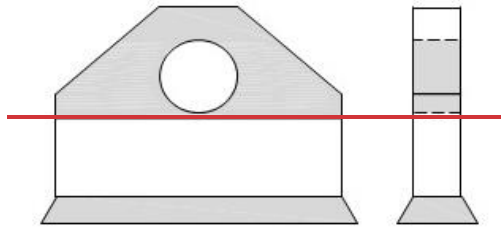


Figure G.5—NDE Regions on Fabricated Pad Eyes

Maintenance

~~Pad eyes and framework on permanently installed equipment may not be practical or accessible subsea for inspection or testing.~~

Marking Requirements

~~Pad eyes intended for lifting are painted red and properly marked per 5.5.2.~~

~~(informative)~~

~~Design and Testing of Subsea Wellhead Running, Retrieving, and Testing Tools~~

~~General~~

~~Annex H addresses the design and testing of tools for running, retrieving, and testing all subsea wellhead components, including guidance equipment, housings, casing suspension equipment, annulus sealing equipment, and protective devices.~~

~~Design~~

~~Loads~~

~~The following loads may apply:~~

~~suspended weight;~~

~~external bending and tension loads;~~

~~internal and external pressure;~~

~~torsional loads;~~

~~pressure separation loads, which shall be based on worst-case sealing conditions (leakage to the largest redundant seal diameter shall be assumed, unless relief is provided as described in 5.1.2.1);~~

~~installation/workover overpull;~~

~~environmental loads;~~

~~mechanical installation (impact) loads;~~

~~hydraulic coupler thrust and/or preloads.~~

~~End Connections~~

~~Tool joints shall be in accordance with API 5DP. Casing threads shall be in accordance with API 5B or with the manufacturer's written specification. The tool shall have an adequate dimension for tonging. The load capacity of the tool shall not be inferred from the choice of end connections for the tool.~~

~~Torque-operated tools shall preferably use left-hand torque for make-up and right-hand torque for release to prevent back-off of casing/tubing/drill pipe threads during operation/disconnection.~~

~~Vertical Bore~~

~~Tools with through-bore shall have a sufficient ID and internal transitions to allow the passage of tools required for subsequent operations in accordance with the manufacturer's written specification.~~

~~Outside Profile~~

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~~The length, outside profile, and fluid-bypass area should be designed to minimize surge/swab pressure and for ease of running while tripping and circulating.~~

~~Load Capacity~~

~~Tool load ratings shall be in accordance with the manufacturer's written specification.~~

~~Vent~~

~~The conductor housing running tool shall be provided with a vent or system of vents. This system of vents is used either to fill the conductor with fluid during running or to allow the passage of cuttings during a jetting operation.~~

~~Pressure Rating~~

~~The pressure and depth rating of the tool shall be in accordance with the manufacturer's written specification.~~

~~Materials~~

~~Selection~~

~~The materials used in these tools shall be chosen for strength, and it is not necessary that they be resistant to corrosive environments. They shall conform to the manufacturer's written specification.~~

~~NOTE—If exposure to severe stress-cracking environments is expected, special practices beyond the scope of this specification can be required.~~

~~Coatings~~

~~Coatings shall conform to 5.1.4.5.~~

~~Testing~~

~~Validation~~

~~Validation shall conform to 5.1.7.~~

~~Factory Acceptance Testing~~

~~All tools shall be tested and dimensionally inspected to confirm their correct operation prior to shipment from the manufacturer's facility. Tools with hydraulic operating systems shall have the hydraulic system tested in accordance with the manufacturer's written specification. This hydrostatic test shall consist of three parts:~~

~~primary pressure-holding period;~~

~~reduction of the pressure to zero (atmospheric);~~

~~secondary pressure-holding period.~~

~~Each holding period shall not be less than 3 minutes, the timing of which shall not start until the external surfaces of the body members have been thoroughly dried, the test pressure has been reached, and the equipment and the pressure-monitoring gauge have been isolated from the pressure source.~~

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~~Hydrotesting to RWP is sufficient for running tools that are assembled entirely with previously hydrotested equipment.~~

For API Committee Work Only

~~(informative)~~

~~Procedure for the Application of a Coating System~~

~~General~~

~~Annex I covers a system for the application of a standard protective paint coating to subsea equipment.~~

~~Purpose~~

~~The purpose of this protective coating procedure is to ensure the proper preparation of the material and proper application of the coating. There is a number of paint companies that manufacture high-quality two-part epoxy-polyamide or polyamine paints suitable for coating subsea equipment. This annex describes how to apply this type of paint to the subsea equipment. This annex describes only one of the many acceptable coating systems and should be regarded as typical of how coating systems should be applied.~~

~~Surface Preparation~~

~~Required Finish~~

~~All surfaces to be coated shall be grit blasted to near-white metal finish in accordance with one of the following standards:~~

~~NACE No. 2;~~

~~SSPC-SP 10;~~

~~ISO 8501-1.~~

~~Required Cleanliness~~

~~Any oil and/or grease shall be removed with an appropriate solvent before priming.~~

~~Atmospheric Conditions~~

~~Blast cleaning shall not be carried out on wet surfaces, nor shall blast cleaning be carried out when surfaces are less than 5 °F (3 °C) above dew point.~~

~~Air Supply~~

~~The compressed-air supply used for blasting shall be supplied at a minimum pressure of 70 psi (0.5 MPa) and shall be free from water and oil.~~

~~Use of Chemicals~~

~~No acid washes or other cleaning solutions, including inhibited washes intended to prevent rusting, shall be used on metal surfaces after they have been blasted.~~

~~Surface Laminations~~

~~Surface laminations shall be ground out and weld splatter shall be removed. Other surface irregularities, including rough capping, undercut and slag, together with sharp or rough edges, fins and burrs, shall be power wire-brushed, ground, chipped, or blasted as necessary to render the substrate suitable for coating.~~

Masking

~~Areas that are not being painted and that require protection shall be adequately masked.~~

Rust Removal

~~If any rust forms after initial blasting, the rusted surfaces shall be re-blasted and cleaned prior to priming.~~

Priming

Cleaning

~~All sand and dust shall be blown from the surfaces being primed with dry, oil-free compressed air or nitrogen gas.~~

Application

~~The primer shall be applied with spray, preferably airless spray equipment.~~

Timing

~~Blast cleaned surfaces shall be coated with the specified primer within 4 hours after grit blasting.~~

Humidity

~~The primer shall be applied within the relative humidity specified by the paint manufacturer.~~

Coating Systems

Typical Coating Materials

The following are typical coating materials:

primer: polyamide or polyamine or epoxy primer, 2.5/4.0 mils dry film thickness;

finish coat: polyamine glass flake epoxy, 12/20 mils dry film thickness.

~~Alternative coatings may be used providing that none of the products contains heavy metals such as lead, chrome, etc.~~

Drying Times

~~Drying times between coats shall be strictly in accordance with the paint manufacturer's instructions.~~

Instructions Preparation/Application

~~All coatings shall be mixed, thinned, and applied in accordance with the manufacturer's instructions.~~

Legislative Requirements

~~All products used shall meet any applicable legislation in the country of manufacture and country where used with regard to volatile organic compounds.~~

Finish Coat Color

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~~Finish-coat color for subsea equipment shall meet the requirements of API 17H.~~

~~Touch-up of Coating System~~

~~General~~

~~All touch-up coatings shall be the same manufacturer's materials as the original coatings. Where sandblasting is impractical, power wire brushing to remove all oxidation is acceptable. The area within 6 in. (150 mm) of the damaged area may also be wire brushed or lightly sanded by hand to roughen the epoxy to promote adhesion.~~

~~Repair of Coating Damage Down to Metal~~

~~Clean area with solvent to remove all oil and grease; wire brush if shiny. If the manufacturer supplies a solvent to assist during repairs, apply the solvent to the coated areas adjacent to the damaged area. When the adjacent coating becomes tacky, apply the coating system described in I.5.1.~~

~~Repair of Epoxy Coating Damage Not Extending to Metal~~

~~Sand and feather out the area being repaired. Clean off with dry, oil-free compressed air or nitrogen gas. Apply the high-solid epoxy coatings as necessary to achieve the original finish.~~

~~Inspection~~

~~Coating Thickness~~

~~A calibrated paint-film thickness device shall be used to measure thickness of the dry film at each stage of the painting process.~~

~~Correcting Coating Thickness~~

~~When dry-film thicknesses are less than those specified, additional coatings shall be applied as necessary to achieve specified thickness.~~

~~Coating Defects~~

~~All coatings shall be free of pin holes, voids, bubbles, and other holidays.~~

(informative)

Validation of Valves and Actuators/Operators

Scope

Annex J provides a method of conducting validation on valves conforming to this specification, by prescribing the types of cycles and the order in which the cycles are to be performed.

General Requirements

A cycle is completed when the valve moves through the positions listed in Table J.1. Pressure, if required in the cycle, would be applied against the closed valve sealing mechanism and then the valve opened against full differential pressure. Unless otherwise noted, all testing specified in this annex shall be performed on the same (single) valve or actuator/operator, without the valve or actuator/operator being disassembled, without maintenance on the valve or actuator/operator, without the addition of lubricant or sealant to the valve or actuator/operator, and without replacing seals or components within the valve or actuator/operator.

Table J.1—Valve Cycle Position

Valve Style	Starting Position	Intermediate Position	Final Position
Fail-closed	Closed	Open	Closed
Fail-open	Open	Closed	Open
Fail-in-place	Closed	Open	Closed
Manual	Closed	Open	Closed

In the event of failure during validation, subsequent testing shall start from the beginning of the validation per this annex. However, troubleshooting such as stroking of the valve and re-starting a seal test are permitted.

Hyperbaric cycles may be performed in a suitable test fixture simulating hyperbaric pressure.

During the hyperbaric functional cycles, valve internal pressure and chamber pressure shall be monitored to prevent overpressure of the chamber due to valve leakage.

Testing of valves shall be performed in one flow direction only, unless otherwise specified.

Endurance cycles and hyperbaric cycles may be performed in either order, but both shall be performed after the PR2 sequence per API 6A, F.2.2.

Hydrostatic testing shall conform to API 6A, F.1.7, and gas testing shall conform to API 6A, F.1.8, unless specified otherwise.

Validation of Actuated Valves

General

~~The following tests shall be conducted on an actuated valve assembly. The valve shall be tested in one of two configurations:~~

~~With an actuator conforming to this specification.~~

~~NOTE—In this configuration, the valve can be validated if all requirements of J.3 are satisfied, and the fluid powered actuator can be concurrently validated if all requirements of J.4 are satisfied. Refer to J.5 for manual valves.~~

~~With a test actuator or fixture that provides the functionality and output forces/torques required of a production style actuator.~~

Initial Function Test of Valve

~~Before performing all testing described below, the valve shall undergo FAT per 7.10.4.2.2. The valve is not required to be submerged.~~

Endurance Cycling Test

~~NOTE 1—The full execution of J.3.3 completes the 600 endurance cycles required by Table 5.~~

~~The initial test sequence shall be performed as per API 6A, F.2.2 for PR2 valves.~~

~~NOTE 2—This satisfies 200 of the 600 endurance cycles and the 3 temperature cycles required by Table 5.~~

~~A total of 200 hyperbaric cycles shall be performed in accordance with Annex N (of this specification), except that testing shall be conducted at a temperature not to exceed 120 °F (49 °C). After closure of the valve bleed the downstream pressure to 1 % or less of the test pressure.~~

~~NOTE 3—This satisfies the 200 pressure/load cycles and 200 of the 600 endurance cycles required by Table 5.~~

~~Additional cycles shall be performed in accordance with API 6A, F.2.2.2.2, except the number of cycles shall be 200.~~

~~NOTE 4—This will satisfy 200 of the 600 endurance cycles required by Table 5.~~

Final Testing

~~After all testing described above is completed, the valve shall be subjected to a gas body and seat test in accordance with 5.4.6.3 and 5.4.6.4, except that the low pressure test shall be performed at 500 psi \pm 30 psi (3.5 MPa \pm 0.2 MPa). Low pressure tests conducted below 500 psi are acceptable if agreed by the manufacturer and user/purchaser. The leakage acceptance criteria shall be in conformance with API 6A—Table F.1, except that no external leakage (e.g. from a stem seal or bonnet gasket) is allowed.~~

~~The tested valve shall be disassembled and inspected. All relevant items should be photographed. Documentation of the examination shall include a written statement that the valve did not sustain damage or wear to an extent that the performance requirements were not satisfied.~~

Validation of Hydraulic Actuators

General

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~~The following test shall be conducted on an actuator assembly. The actuator shall be tested in one of two configurations.~~

~~With a valve conforming to this specification.~~

~~NOTE In this configuration, the valve can be validated if all requirements of J.3 are satisfied, and the fluid powered actuator can be concurrently validated if all requirements of J.4 are satisfied. Refer to J.5 for manual valves.~~

~~With a test valve or fixture that provides the functionality and output forces/torques required of a production-style valve.~~

~~A cycle is defined as moving the operating portion of the actuator from the normal position to its full opposite position and back to normal. If the bonnet assembly is part of the actuator, validation of the stem seal and bonnet design shall be performed to validate these design elements to the requirements for valves.~~

Initial Function Test of an Actuator

~~Actuators shall be subjected to a functional test per 7.10.4.2.3.1, 7.10.4.2.3.2, and 7.10.4.2.3.3; 7.10.4.2.3.4 shall be performed as well if a compensation system is required by the manufacturer for validation.~~

Endurance Cycle Testing

~~NOTE 1 The full execution of J.4.3 completes the 600 endurance cycles required by Table 5.~~

~~The initial test sequence shall be performed as per API 6A, F.2.3 for PR2 actuators.~~

~~NOTE 2 This satisfies 200 of the 600 endurance cycles and the three temperature cycles required by Table 5.~~

~~A total of 200 hyperbaric cycles shall be performed in accordance with Annex N (of this specification), except that testing shall be conducted at a temperature not to exceed 120 °F (49 °C).~~

~~NOTE 3 This satisfies the 200 pressure/load cycles and 200 of the 600 endurance cycles required by Table 5.~~

~~Testing shall also be performed to satisfy the requirements of 7.10.4.1.3 and may be performed at any time during the hyperbaric testing.~~

~~Additional cycles shall be performed in accordance with API 6A, F.2.3.2.2 except the number of cycles shall be 200.~~

~~NOTE 4 This satisfies 200 of the 600 endurance cycles required by Table 5.~~

Final Testing

~~After the testing listed above is completed, the actuators shall be subjected to a functional test per 7.10.4.2.3.3. The testing specified in 7.10.4.2.3.4 shall also be performed if a compensation system is required by the manufacturer for validation.~~

~~The tested actuator shall be disassembled and inspected. All relevant items should be photographed. Documentation of the examination shall include a written statement that the actuator did not sustain damage or wear to an extent that the performance requirements were not satisfied.~~

Validation of Valves with Manual Operator (ROV/Diver Operated)

General

~~The following tests shall be conducted on a valve with manual operator (ROV/diver operated).~~

Initial Function Test of Valve

~~Initial function testing shall be performed as specified in J.3.2.~~

Pressure/Temperature Testing

~~Pressure/temperature testing shall be performed in conformance with API 6A, F.2.2. Unless the requirements of 5.1.7.2 apply, validated designs modified for subsea use shall not require revalidation; only the additional validation is required.~~

Hyperbaric Pressure Testing

~~The hyperbaric pressure testing cycles may be completed on a different valve than that which was tested to satisfy J.5.3. For example, if a manual valve has been validated per API 6A and the subsea version is the same design that did not undergo substantive change (see 5.1.7.2) for the addition of ambient pressure seals (e.g. a sealed bearing cap), then the hyperbaric pressure cycles alone may be performed on the subsea version.~~

~~Testing shall be performed to verify operability of the manual valve in installed conditions (water depth) per the manufacturer's written specification. The actuator should operate smoothly (no evidence of stick-slip movement, sometimes referred to as chatter) in either direction. The hyperbaric test pressure shall be based on the maximum rated seawater depth specified by the manufacturer. The valve shall operate smoothly throughout its cycle (from fully closed to fully open, and back to fully closed). 200 cycles shall be performed at RWP and maximum hyperbaric pressure.~~

~~Before the opening of the valve, the pressure downstream of the gate shall be reduced to less than 1 % of the RWP.~~

~~If the design of the pressure-containing seals (e.g. body-to-bonnet seals and stem seals) and the stem motion (linear or rotary) is identical to that of an actuated valve, validation of the actuated (or manual) valve shall be acceptable as validation of the manual (or actuated) valve.~~

Final Testing

~~Final testing shall be performed as specified in J.3.4.~~

Other Valves

Check Valves

~~Check valves shall be validated per the requirements in Annex J and Table J.1 for fail-closed valve to complete a total of 400 endurance cycles, 3 temperature cycles, and 200 pressure/load cycles.~~

Initial Function Test of Valve

~~Testing shall be performed as specified in J.3.2.~~

Endurance Cycling Test

~~NOTE 1 — The full execution of J.6.1.2 completes the 400 endurance cycles required by J.6.1.~~

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~~The initial test sequence shall be performed as per API 6A, F.2.2 for PR2 valves.~~

~~NOTE 2 — This satisfies 200 of the 400 endurance cycles and the 3 temperature cycles required by J.6.1.~~

~~A total of 200 hyperbaric cycles shall be performed in accordance with Annex N (of this specification), except that testing shall be conducted at a temperature not to exceed 120 °F (49 °C) and that testing does not require to open the valve with a differential pressure of RWP applied on valve bore sealing mechanism. After closure of the valve bleed the downstream pressure to 1 % or less of the test pressure.~~

~~For check valves without any penetrations running through the body wall, 200 endurance cycles in accordance with API 6A, F.2.2.2.2 may be performed in lieu of the 200 hyperbaric cycles.~~

~~NOTE 3 — This satisfies the 200 pressure/load cycles and 200 of the 400 endurance cycles required by J.6.1.~~

~~Final Testing~~

~~Final testing shall be performed as specified in J.3.4.~~

~~Needle Valves~~

~~Needle valves shall be validated per the requirements in Annex J for actuated or manual valves as applicable.~~

~~Documentation~~

~~Documentation shall be per API 6A, F.1.15. In addition, the following shall be contained or referenced:~~

~~names and affiliations of designated witnesses and of test facility personnel supervising the testing;~~

~~assembly and component traceability as specified by the manufacturer (assembly number, part numbers, revisions, serial numbers, material, weld nondestructive examinations, etc.);~~

~~critical dimensions.~~

(informative)

Screening Tests for Material Compatibility

General

As reservoirs and environment become more complex and subject to acute temperature changes, injection of chemical additives into remote subsea completions is done to refine the fluid-flow properties of wellbore fluids and inhibit the formation of precipitates and crystalline structures that can block fluid flow. These additives are often proprietary mixtures formulated specifically to deal with specific wellbore fluid properties. This annex is presented as a means to provide a standardized set of procedures to validate the additive's compatibility with materials associated with the subsea completion hardware to screen for adverse results that can:

degrade or erode the metallic and nonmetallic materials used for pressure containment and sealing mechanisms;

degrade the overall design life of the subsea hardware.

Listed in this annex are three levels of screening. Level 1 identifies possible chemical and/or physical changes in selected materials. Level 1 is intended to provide general information that can be published by either chemical suppliers and/or manufacturers. Level 2 looks for chemical and/or physical changes in nonmetallic materials, such as swelling, when the material resides in a confined space. Level 2 testing also uses more specific concentrations and operating conditions defined by the user/purchaser for a particular application. Level 2 results are likely to be proprietary and project-specific and might not necessarily be directly comparable to other published level 2 data. Level 3 is an in-depth test to determine the useful operating life of nonmetallic materials in the presence of the additive using accelerated life estimation testing procedures based on the Arrhenius principle.

Level 1 Screening Tests

Unconfined Testing—Placement

Place test specimen in a container with no significant deflection of test specimen.

Elastomers

Test Parameters

The following test parameters apply.

Specimen: O-ring number 214, 0.984 in. (25.0 mm) ID, 0.139 in. (3.53 mm) width.

Container: Covered but not airtight, with a volume that shall be no less than 6.1 in.³ (100 cm³).

Concentration: Neat (full strength; no dilution) and in solution at a concentration typically recommended for the application; solution shall be added during the testing to maintain a 25:1 to 27:1 ratio of fluid volume to seal volume.

Temperature: 140 °F (60 °C); if the boiling point or flash point is close to 140 °F (60 °C), the chemical supplier shall determine the appropriate steps to obtain acceptable results with user/purchaser approval.

Pressure: Ambient.

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~~Duration: 32 days with measurements taken at the start and after 1 day, 2 days, 4 days, 8 days, 16 days, and 32 days; all test samples shall be taken from the same material batch.~~

~~Measurements: For the following measurements, remove the test sample from the oven, towel dry immediately, and cool to $68^{\circ}\text{F} \pm 2^{\circ}\text{F}$ ($20^{\circ}\text{C} \pm 1^{\circ}\text{C}$) prior to taking measurements. Record the weight change, hardness change, and percent volume change within 3 hours after removal from the oven.~~

~~Day 0: Perform tensile test in accordance with ASTM D1414.~~

~~Day 1: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 2: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 4: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 8: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 16: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 32: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 32: Place a sample in an evacuated desiccator at a maximum pressure of 1.5 psi (0.01 MPa) and ambient temperature; allow to dry for 1 week, then perform tensile test in accordance with ASTM D1414.~~

~~Test vessel: The vessel shall be rated for use with the test chemicals, materials, temperatures, and pressures. The fluid capacity shall be such that the ratio of fluid volume to seal volume is in the range 25:1 to 27:1.~~

Acceptance Criteria for Compatibility

The following acceptance criteria shall apply:

percent weight change: $\pm 10\%$;

hardness change: _____

for < 90 durometer (Shore A), $+10/-20$ points;

for 90 durometer (Shore A), $+5/-20$ points;

for > 90 durometer (Shore A), $+5/-20$ points;

percent volume change: $+25\%/-5\%$;

appearance: no blistering, cracking, disintegration, or change in the appearance of the chemical (color, precipitates, etc.) with no magnification.

Metals

Test Parameters

The following test parameters apply.

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~~Specimen: Recommended sample size is 1.0 in. × 3.0 in. × 0.25 in. (25.4 mm × 76.2 mm × 6.35 mm). Specimen may be coated, clad, or plated to test coating/plating material compatibility. An uncoated control specimen of the base metal and size shall be tested in a separate test vessel.~~

~~Minimum ratio of volume to surface area shall be 1:6; surface finish shall be 125 μ in. (3.2 μ m) RMS or better.~~

~~Container: Covered but not airtight, with a volume that shall be no less than 6.1 in.³ (100 cm³).~~

~~Concentration: Neat (full strength; no dilution) and in solution at a concentration typically recommended for the application; solution shall be added during the testing to maintain a 25:1 to 27:1 ratio of fluid volume to seal volume.~~

~~Temperature: 140 °F (60 °C); if the boiling point or flash point is close to 140 °F (60 °C), the chemical supplier shall determine the appropriate steps to obtain acceptable results with user/purchaser approval.~~

~~Pressure: Ambient.~~

~~Duration: 4 weeks with measurements taken at the start, after 1 week, after 2 weeks, and after 4 weeks.~~

~~Test vessel: The vessel shall be rated for use at the test chemicals, materials, temperatures, and pressures. The fluid capacity shall be such that the ratio of fluid volume to seal volume is in the range of 25:1 to 27:1.~~

~~Photographs shall be taken to document the initial surface finish and final surface finish.~~

Acceptance Criteria for Compatibility

The following acceptance criteria shall apply.

~~Appearance: No change in the color or in the observable finish at 10× magnification, or in the appearance (color, precipitates, etc.) of the chemical.~~

~~Corrosion rate: Report mils per year. Using 100 % survey on a minimum of the two largest sides, define pitting and depth using 10× magnification.~~

~~Surface finish: 125 μ in. (3.2 μ m) RMS or better (no change).~~

Level 2 Screening Tests

Confined Testing—Nonmetallic Materials (Elastomers and Plastics)

The following test parameters apply.

~~Specimen: O-ring number 214, 0.984 in. (25.0 mm) ID, 0.139 in. (3.53 mm) width.~~

~~Test container: With recommended O-ring gland dimensions for number 214 O-ring, static application.~~

~~Concentration: Neat (full strength; no dilution) and also in solution at a concentration typically recommended for the application; solution shall be added during the testing to maintain a 25:1 to 27:1 ratio of fluid volume to seal volume.~~

~~Temperature: 140 °F (60 °C); if the boiling point or flash point is close to 140 °F (60 °C), the chemical supplier shall determine the appropriate steps to obtain acceptable results with user/purchaser approval.~~

~~Pressure: Ambient.~~

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~~Duration: 32 days with measurements taken at the start, after 1 day, after 2 days, after 4 days, after 8 days, after 16 days, after 32 days; all test samples shall be taken from the same material batch.~~

~~Measurements: For the following measurements, remove the test sample from the oven, towel dry immediately, and cool to $68^{\circ}\text{F} \pm 2^{\circ}\text{F}$ ($20^{\circ}\text{C} \pm 1^{\circ}\text{C}$) prior to taking measurements. Record the weight change, hardness change, and percent volume change within 3 hours after removal from the oven.~~

~~Day 0: Perform tensile test in accordance with ASTM D1414.~~

~~Day 1: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 2: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 4: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 8: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 16: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 32: Towel dry; determine changes in weight, hardness, percent volume, and appearance.~~

~~Day 32: Place a sample in an evacuated desiccator at a maximum pressure of 1.5 psi (0.01 MPa) and ambient temperature; allow to dry for 1 week, then perform tensile test in accordance with ASTM D1414.~~

~~Test vessel: The vessel shall be rated for use with the test chemicals, materials, temperatures, and pressures. The fluid capacity shall be such that the ratio of fluid volume to seal volume is in the range 25:1 to 27:1.~~

Acceptance Criteria for Compatibility

The following acceptance criteria shall apply:

percent weight change: $\pm 10\%$;

hardness change: _____

for < 90 durometer (Shore A), $+10/-20$ points;

for 90 durometer (Shore A), $+5/-20$ points;

for > 90 durometer (Shore A), $+5/-20$ points;

percent volume change: $+25\%/-5\%$;

percent tensile strength change: $\pm 50\%$;

percent change in the % elongation: $\pm 50\%$;

percent change in the 50 % modulus: $\pm 50\%$;

appearance: no blistering, cracking, disintegration, or change in the appearance of the chemical (color, precipitates, etc.) with no magnification.

Level 3 Screening Tests

Life Estimation and Aging

To approximate the life of a nonmetallic material for use in a severe service environment, tests should be conducted in the specific environment under accelerated temperature and/or pressure conditions. Without some type of accelerated testing, it can be difficult to quantify the service life of an elastomeric component. Elevated temperature and/or pressure testing can provide a useful method for estimating nonmetallic material capabilities under realistic conditions.

Life estimation testing may be considered as the best estimate of long-term service life to evaluate the long-term performance of a nonmetallic material in a severe service environment. The basic technique involves collecting time-to-failure data at elevated temperatures (higher than the maximum anticipated service temperature) and plotting the results on semi-log graph paper. The vertical scale is the log of the time to failure and the horizontal scale is the reciprocal of the absolute temperature (see API 6J1—Figure 1, for a typical life estimation plot). Alternately, the time to failure at the service temperature also can be calculated from the appropriate mathematical equations.

Certain precautions should be exercised when performing accelerated temperature and/or pressure tests. It should be verified experimentally that the failure mechanism (and activation energy) does not change with elevated temperatures or pressures. In addition, it shall be recognized that gas diffusion can occur through an elastomer seal at an accelerated rate and this shall be properly accounted for if this is used as failure criteria. It also may be helpful to test a nonmetallic material with known field performance as a reference for comparison; see level 2 tests. Stagnant fluids and gases can give better or worse life estimation than if the fluids are periodically refreshed.

Examples of accepted industrial procedures that use Arrhenius aging techniques include:

API 6J1;

ASTM D3045;

ASTM D2990;

ISO 23936 (all parts);

UL 746B.

Aging tests and life estimation of elastomeric materials should be as given in API 6J1, Section 5 and Figure 2, or in ISO 23936. Reporting should be as given in ISO 23936. Specimen size should be similar to an O-ring number 325, with an ID of 1.475 in. (37.47 mm) and a width of 0.210 in. (5.33 mm).

Aging tests and life estimation of thermoplastic materials should be as given in ISO 23936. Reporting should be as given in ISO 23936. Specimen size should be similar to an O-ring number 325, with an ID of 1.475 in. (37.47 mm) and a width of 0.210 in. (5.33 mm).

—Rapid Gas Decompression Testing

Rapid gas decompression tests should be as given in ISO 23936. Reporting should be as given in ISO 23936. Specimen size should be similar to an O-ring number 325, with an ID of 1.475 in. (37.47 mm) and a width of 0.210 in. (5.33 mm).

(informative)

Subsea Tubing Hanger

Subsea tubing hangers are located in the wellhead, tubing head (wellhead conversion assembly), or horizontal tree.

They suspend the tubing, seal off the production, and provide sealing pockets for the production and control stabs as a minimum. Horizontal trees also have annular seals for the horizontal side outlets.

Tubing hangers having multiple bores require orientating relative to the PGB to ensure that the tree engages with the tubing hanger when installed. It is normal to orientate tubing hangers with horizontal production outlets to give a smooth flow passage between the tubing hanger and horizontal tree. Concentric tubing hangers do not necessarily require orientation, unless required because of providing downhole instrumentation.

After installation, the tubing hanger is locked into the mating wellhead, tubing head, etc., to resist the force due to pressure in the production casing and to resist thermal expansion. Lock mechanisms may be mechanically or hydraulically actuated depending on water depth and specific project requirements.

Major elements of the tubing hanger system are:

tubing hanger:

concentric (see Figure L.1);

multiple bores (see Figure L.2);

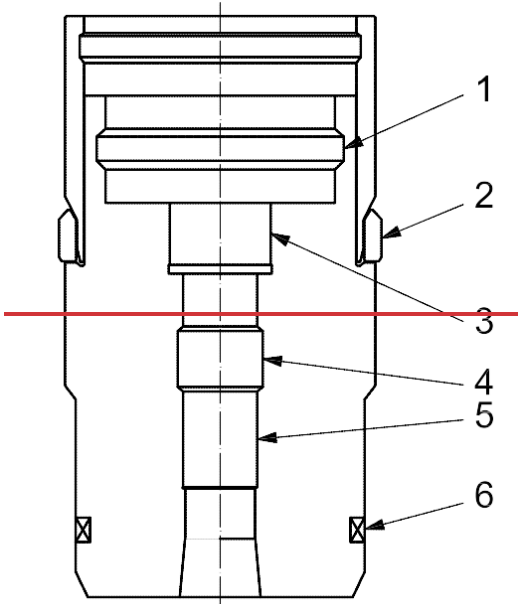
horizontal tree (see Figure L.3);

horizontal tree, extended (see Figure L.4);

tubing hanger running tool;

orientation device;

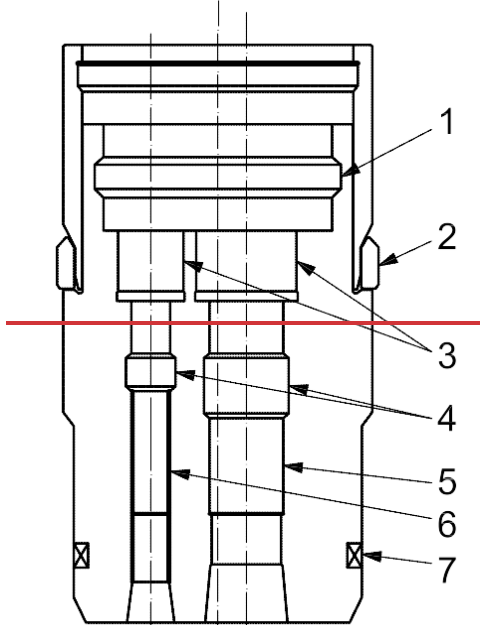
miscellaneous tools.



Key-

- 1 — running tool latching groove
- 2 — lockdown
- 3 — stab sub seal pockets
- 4 — wireline plug profiles
- 5 — production bore
- 6 — seal

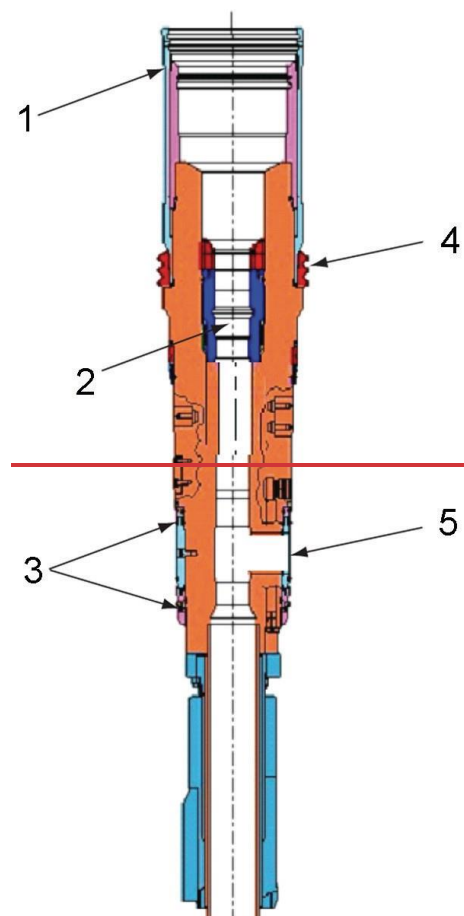
Figure L.1—Concentric Tubing Hanger



Key

- 1 — running tool latching groove
- 2 — lockdown
- 3 — stab sub seal pockets
- 4 — wireline plug profiles
- 5 — production bore
- 6 — annulus bore
- 7 — seal

Figure L.2—Tubing Hanger with Multiple Bores



Common names for individual components are included in the numbered key.

Key

running tool latching groove

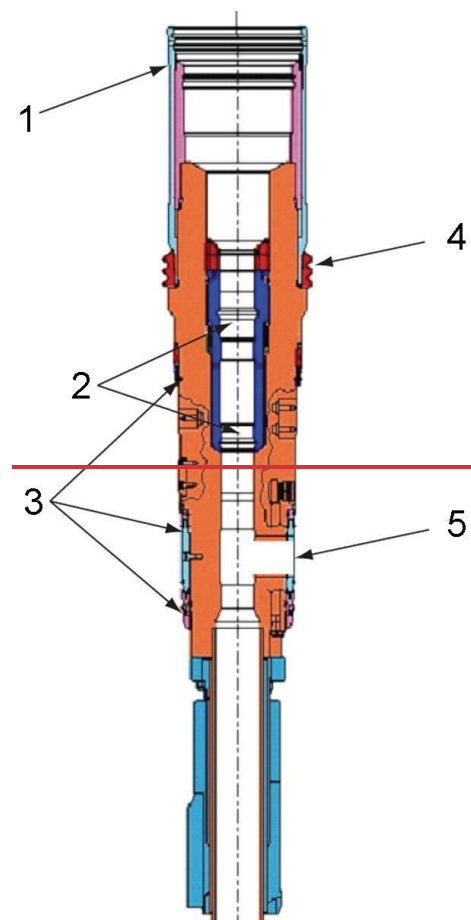
wireline plug profile or closure device

seal

lockdown

production outlet

Figure L.3—Tubing Hanger for Horizontal Tree



Common names for individual components are included in the numbered key.

Key

running tool latching groove

wireline plug profile or closure devices, two

seal

lockdown

production outlet

Figure L.4—Extended Tubing Hanger for Horizontal Tree

(informative)

Drill-through Mudline Suspension Systems

Drill-through mudline suspension equipment is used to suspend casing weight at or near to the mudline and to provide pressure control. Drill-through mudline suspension equipment is used when drilling with a bottom-supported rig when it is anticipated that the well can be completed subsea. During drilling, workover, and completion operations, the BOP is located at the surface. The system differs from mudline suspension in that the surface casing is suspended from a wellhead (high-pressure) housing and subsequent casing strings use wellhead-like hangers and annulus seal assemblies. The hangers have positive landing shoulders; therefore, their OD is normally too large to allow running them through casing tiebacks. It is usual to use risers having a pressure rating and bore equivalent to the surface BOP for the installation of casing hangers, seal assemblies, internal abandonment caps, and tubing hangers. The wellhead (high-pressure) housing contains the necessary profile for locking down the tubing hanger and has an external profile to which the subsea tree can be locked; therefore, drill-through mudline requires no-conversion equipment.

Major items of equipment used with drill-through mudline suspension are:

conductor (low-pressure) housing;

surface casing hanger;

wellhead (high-pressure) housing;

casing hangers;

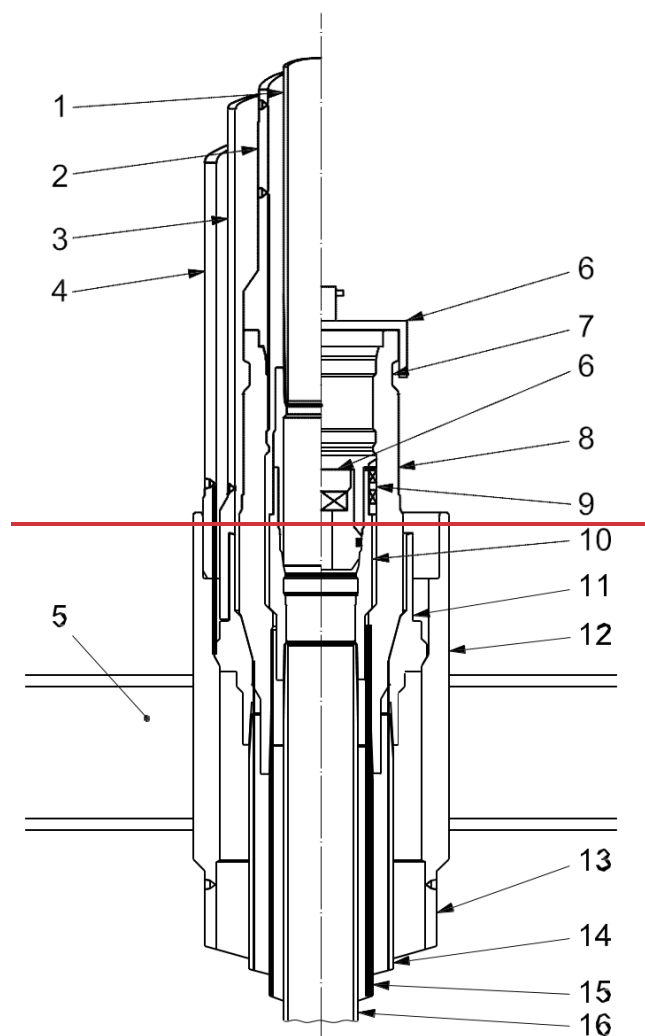
annulus seal assemblies;

bore protectors and wear bushings;

abandonment caps;

running, retrieving, and test tools.

Figure M.1 illustrates the items of equipment used in drill-through mudline suspension systems.



Key

- 1 — casing, 9⁵/₈ in. to 10³/₄ in. (244 mm to 273 mm)
- 2 — riser, 16 in. (406 mm)
- 3 — riser, 24 in. (610 mm)
- 4 — environmental tieback pipe
- 5 — guidance equipment
- 6 — abandonment cap
- 7 — connector profile
- 8 — wellhead (high-pressure) housing
- 9 — seal assembly
- 10 — production casing hanger

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11 — ~~hanger, 18⁵/₈ in. to 20 in. (473 mm to 508 mm)~~

12 — ~~conductor (low-pressure) housing~~

13 — ~~conductor, 30 in. (762 mm)~~

14 — ~~casing, 18⁵/₈ in. to 20 in. (473 mm to 508 mm)~~

15 — ~~casing, 13³/₈ in. (340 mm)~~

16 — ~~casing, 9⁵/₈ in. to 10³/₄ in. (244 mm to 273 mm)~~

Figure M.1—Drill-through Mudline Suspension System

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(informative)

Hyperbaric Testing Guidelines

Table N.1 lists subsea equipment that should be subjected to hyperbaric (external) pressure testing to validate performance under installed (water-depth) conditions. The hyperbaric test pressure should be based on the maximum rated water depth (1.0x water depth pressure) specified by the manufacturer for the equipment. If agreed between the user/purchaser and the manufacturer, the hyperbaric test medium should be maintained at $40^{\circ}\text{F} \pm 10^{\circ}\text{F}$ ($4^{\circ}\text{C} \pm 5^{\circ}\text{C}$) throughout the test.

For static components, the functional cycles specified in Table N.1 should be internal pressure cycles from RWP to fully depressurized (atmospheric pressure), while continuously subjected to external hyperbaric pressure.

For equipment with moving parts, the functional cycles specified in Table N.1 should be dynamic operation cycles (see 5.1.7.7), such that full operating motion of the equipment is achieved; e.g. for valves and chokes, a cycle should consist of starting from the fully closed position, applying a differential bore pressure of RWP, then actuating open under differential pressure and stroking to the full open position with bore pressure vented to atmospheric. The specified number of cycles should be completed with the equipment continuously subjected to external hyperbaric pressure.

During the hyperbaric functional cycles, leakage should not exceed that specified in API 6A, Annex F, for PR2F. A single internal hydrostatic test (see 5.4) should be performed for acceptance after all hyperbaric functional cycles have been completed and hyperbaric conditions depressurized to atmospheric pressure. Hold time should be 15 minutes minimum. Leakage should not exceed the acceptance criteria for hold periods specified in API 6A, Annex F, for PR2F.

If agreed between the manufacturer and the user/purchaser, the hyperbaric functional test cycles can be considered as contributing to the 600 life cycle/endurance cycles required by Table 5. For example, a valve and actuator/operator assembly may be subjected to a total of 400 functional cycles, of which 200 are hyperbaric as described in this annex, and 200 are as described in API 6A, Annex F, PR2F, including 20 cycles at maximum rated temperature and at minimum rated temperature.

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Table N.1—Hyperbaric Testing Guidelines

Component	Operational Cycles While Under Hyperbaric Pressure
Metal seal exposed to retained fluids	200 ^b
Metal seal not exposed to retained fluids	3 ^b
Nonmetallic seal exposed to retained fluids	200 ^b
Nonmetallic seal not exposed to retained fluids	3 ^b
QEC	NA
Wellhead/tree/tubing head connectors	NA
Tubing heads	NA
Manual valves	200
Valve operated with actuators	200
Tree cap connectors	NA
Manual subsea chokes	200
Subsea chokes operated with actuators	200
Subsea wellhead casing hangers	NA
Subsea wellhead annulus seal assemblies (including backup annulus seal assemblies)	NA
Subsea tubing hangers, HXT internal tree caps, and crown plugs	NA
Poppets, sliding sleeves, and check valves	200
Mudline tubing heads	NA
Mudline wellhead, casing hangers, tubing hangers	NA
Running tools (including tree running tool connectors) ^a	NA

~~Subsea wellhead running tools are not included.~~

~~Applicable if seal is directly exposed to hyperbaric conditions in service.~~

(informative)

Vertical Subsea Trees

~~Vertical subsea trees are installed either on the wellhead or on a tubing head, after the subsea tubing hanger has been installed through the drilling BOP stack and landed and locked into the wellhead or tubing head. The production flow path is through the valves mounted in the vertical bore(s) and either out of the top of the tree during workover and testing [in special applications production (injection) may be via the top of the tree] and during production (injection) via the production outlet that branches off the vertical bore.~~

~~The subsea tree may have a concentric bore or may have multiple bores. Annulus access may be through one of the tree bores or it may be through a side outlet in the tubing head, below the tubing hanger.~~

~~The production outlet may be at 90° to the production bore or may be angled to best suit flow requirements.~~

~~Figure O.1 and Figure O.2 illustrate the major items of equipment in vertical subsea trees. The arrangements shown are typical and should not be construed as requirements.~~

~~Major items of equipment in a subsea tree are:~~

~~CGBs and tubing head;~~

~~tree wellhead connector;~~

~~tree stabs and seal subs;~~

~~valves, valve blocks, and valve actuators/operators;~~

~~tree re-entry interface;~~

~~tree cap;~~

~~tree cap running tool;~~

~~tree piping;~~

~~tree guide frame;~~

~~tree running tool;~~

~~flowline connectors;~~

~~flowline connector support frame;~~

~~subsea chokes and actuators/operators;~~

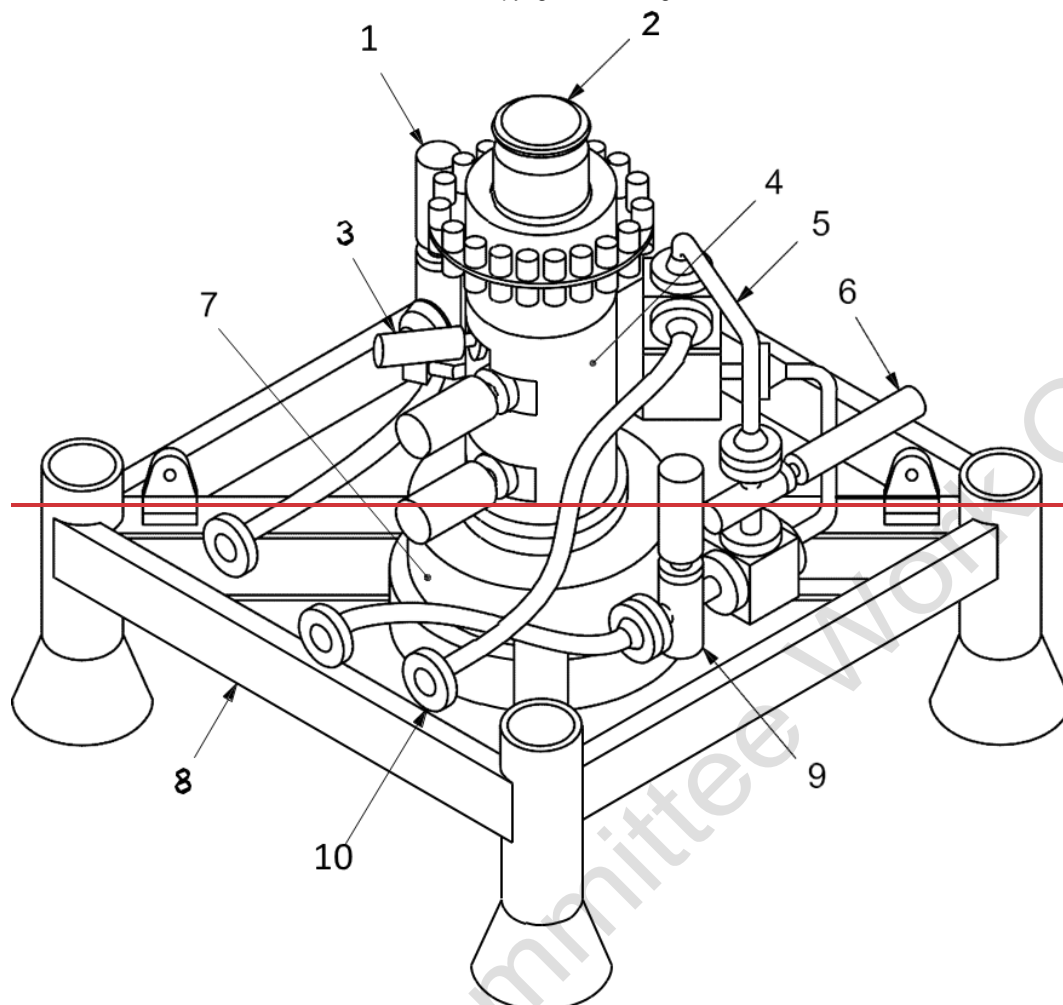
~~tree-mounted control interfaces;~~

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~~control pod interface.~~

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Key

PWV — 6 — XOV

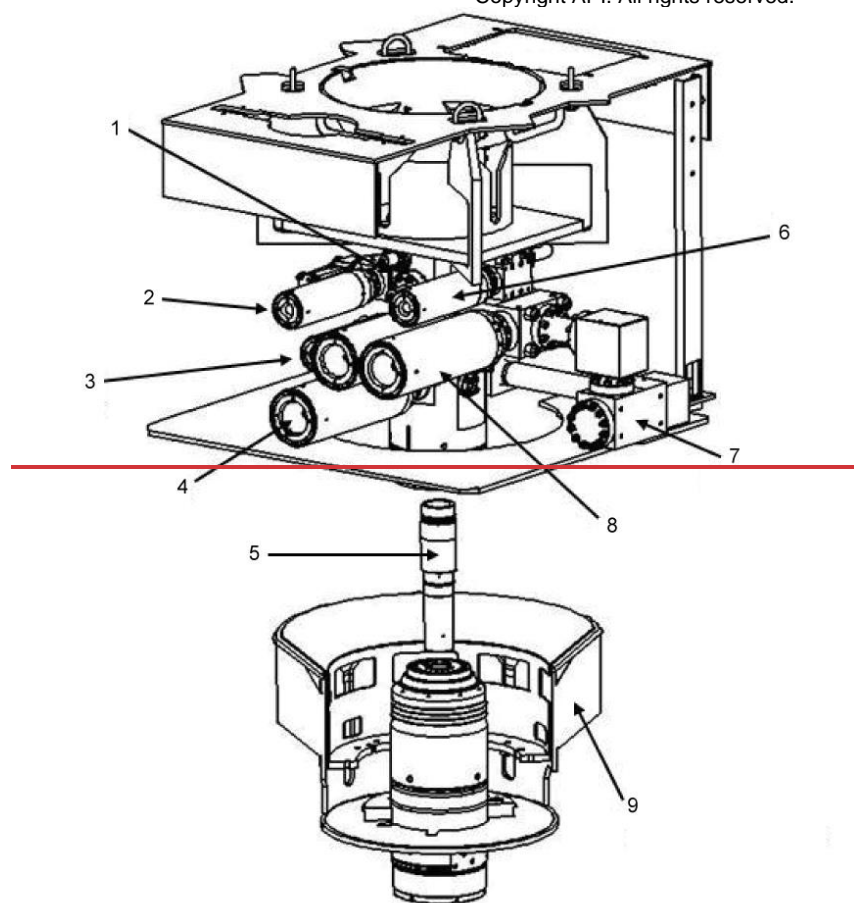
tree cap 7 — tree connector

PSV — 8 — tree guide frame

master valve block — 9 — AWW

flow loop 10 — flowline connection

Figure O.1—Guideline Style Vertical Tree



Key

- | | | |
|----------------|---------------------|----------------------------|
| 1 swab valves | 5 tubing hanger | 9 GRA, CGB, or tubing head |
| 2 AMV | 6 XOV | |
| 3 AMV | 7 production outlet | |
| 4 master valve | 8 wing valve | |

Figure O.2—Guidelineless Style Vertical Tree

(informative)

Horizontal Subsea Trees

Several options are available for horizontal tree arrangements. These offer different benefits for installation, retrieval, and maintenance. These are addressed for information only. No attempt is made within this specification to evaluate or recommend an option.

Horizontal subsea trees may be installed after drilling and installation of the complete wellhead system and prior to installation of the tubing completion and tubing hanger. For this mode of operation, the BOP is installed on top of the horizontal subsea tree and the tubing hanger and tubing completion is run through the BOP and landed off on a landing shoulder in the bore of the horizontal subsea tree. The production flow path exits horizontally through a branch bore in the tubing hanger between seals and connects to the aligned production outlet. A typical tree of this type is illustrated in Figure P.1. The arrangement shown in Figure P.1 requires that the tubing completion be retrieved prior to retrieving the tree. The arrangement also includes a pressure-containing internal tree cap above the tubing hanger to provide a second barrier.

In an alternative arrangement, the tubing hanger and internal tree cap are combined into a single extended tubing hanger system suspended in the horizontal tree. It doubles up on the number of isolation plugs and annular seals for barrier protection and features a debris cap that can also serve as a backup locking mechanism for the tubing hanger.

A guidelineless version of the horizontal tree, which is typically a funnel-down arrangement, is shown in Figure P.2. The extended neck on top of the tree is required for clearance for the BOP's re-entry funnel and "swallow" of its connector.

A third configuration, generally referred to as the "drill-through" horizontal tree, allows the installation of the horizontal tree immediately after the wellhead (high-pressure) housing is landed. This system allows carryout of the drilling and installation of casing strings through the horizontal tree, minimizing the number of times it is necessary to run and retrieve the BOP stack. In this configuration, the diameter of the tree bore protector and tubing hanger orientation system should drift the casing hanger and annulus seal assembly.

Horizontal trees may also be used with mudline suspension equipment and drill-through mudline suspension equipment and may, additionally, be configured for artificial lift completions, such as electric submersible pumps or hydraulic submersible pumps.

Horizontal subsea trees use many of the same items of equipment as vertical trees. However, equipment that differs significantly includes:

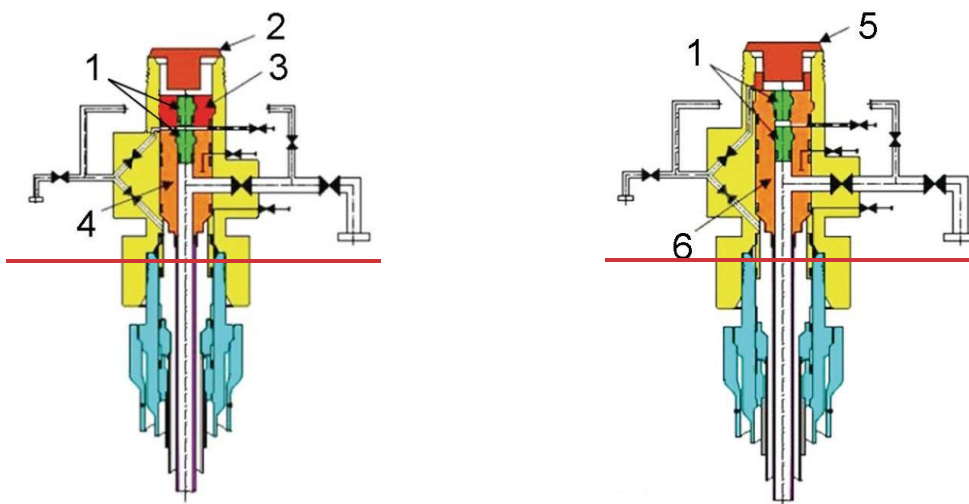
tree body;

tubing hanger;

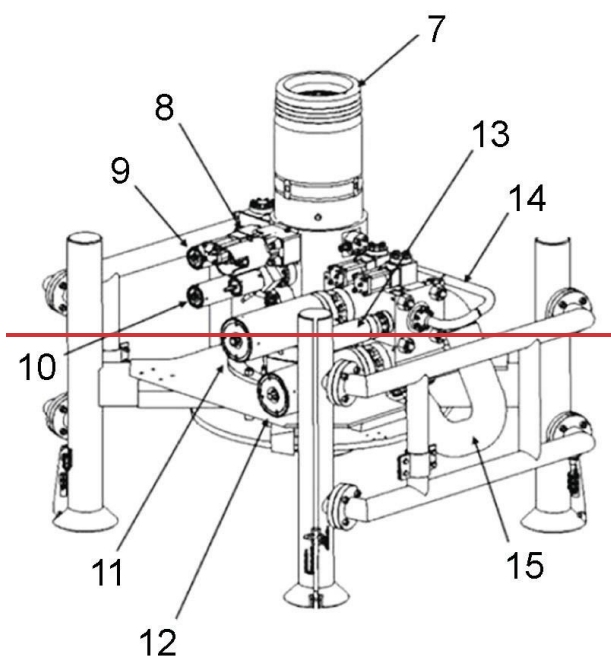
isolation plugs (left in place);

tree cap.

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Common names for individual components are included in the numbered key. The two items not identified are the casing hangers (blue) and tree (yellow).



Key

1	crown-plugs	6	extended tubing hanger	11	master valve
2	debris-cap	7	re-entry interface	12	wing valve
3	internal tree cap	8	ASV	13	XOV
4	tubing hanger	9	AWV	14	crossover flowloop
5	locking cap	10	AMV	15	production outlet

Section 3 Figure P.1—Guideline Style Horizontal Tree: The definitions shall be added and all subsequent definitions updated

3.1.50

Rated working pressure small-bore lines

RWP-SB

Maximum internal pressure (up to 2500psi [17.2MPa] over the tree system RWP) that the Small-Bore Lines are designed to contain and/or control.

3.1.70

Underwater Safety Valve (USV)

Automatic valve assembly installed at a subsea well location that closes on loss of power supply.

NOTE where used in this specification, the term USV is understood to include a valve and actuator.

3.1.71

USV actuator

Device that causes the USV to open when power supply is supplied and to close automatically when power is lost or released.

3.1.72

USV valve

Portion of the USV that contains the well stream and shuts off flow when closed.

Section 5.1.2.1: Update paragraph 1 to the following:

Where small-bore lines [e.g. surface-controlled subsurface safety valve (SCSSV) control lines, chemical injection lines] pass through a cavity such as the tree/tubing hanger cavity, the equipment bounding that cavity shall be hydrostatically pressure tested at or above the maximum rated working pressure (RWP-SB) of any of those small-bore lines, unless a means is provided to monitor and relieve cavity pressure (see Table 6, 7.9.1 and 9.1.7 for additional information).

Table 5

Change "Valve operated with actuators" to " valve operated by actuators"

Section 5.4.5.1. Split paragraph 4 into the following 2 paragraphs:

Momentary pressure drops during the hold period due to sensitivity/noise in electronic data acquisition systems are permitted so long as the final pressure recorded is above the specified minimum test pressure and measurement devices have remained isolated from the pressure source throughout the entire hold period.

NOTE: If a pressure-monitoring gauge and/or chart recorder is used for documentation purposes, the chart record may have a pressure settling rate not exceeding 3 % of the test pressure, or 300 psi (2 MPa) per hour, whichever is less.

Section 5.4.5.2: The following shall be added:

Valves with nonstandard bores shall follow API 6A drift requirements.

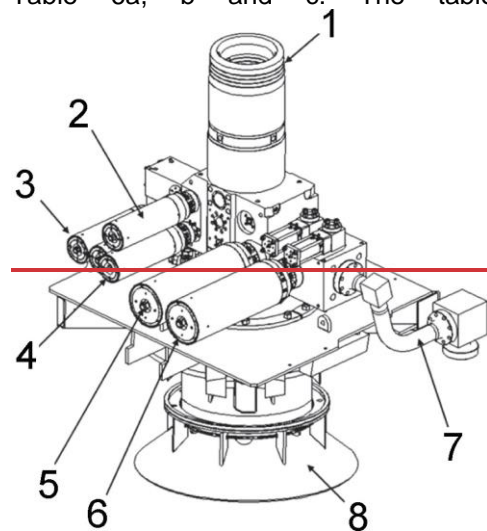
Section 6.2.11: The section shall be updated to the following:

"Threaded connections for chemical injection penetrations shall not be used when inboard of the two closure devices"

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Table 6a, b and c: The tables shall be updated as indicated in the red box



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Key

~~re-entry interface~~ 5 ~~master valve~~

ASV 6 wing valve

AWV 7 production outlet

AMV 8 guidelineless re-entry funnel (funnel down)

Figure P.2—Guidelineless Style Horizontal Tree

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⁷—American National Standards Institute, 1899 L Street, NW, 11th Floor, Washington, DC 20036, www.ansi.org.

⁸—American Welding Society, 8669 NW 36 Street, # 130, Miami, Florida 33166, www.aws.org.

⁹—The International Society of Automation, 67 T.W. Alexander Drive, Research Triangle Park, North Carolina 27709, <https://www.isa.org>.

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~~ISO 10426 (all parts), Petroleum and natural gas industries—Cements and materials for well cementing~~

~~ISO 11961, Petroleum and natural gas industries—Steel drill pipe~~

~~ISO 23936 (all parts)¹⁴, Petroleum, petrochemical and natural gas industries—Non-metallic materials in contact with media related to oil and gas production (formerly: NORSOK M-710, Qualification of non-metallic sealing materials and manufacturers), 2011~~

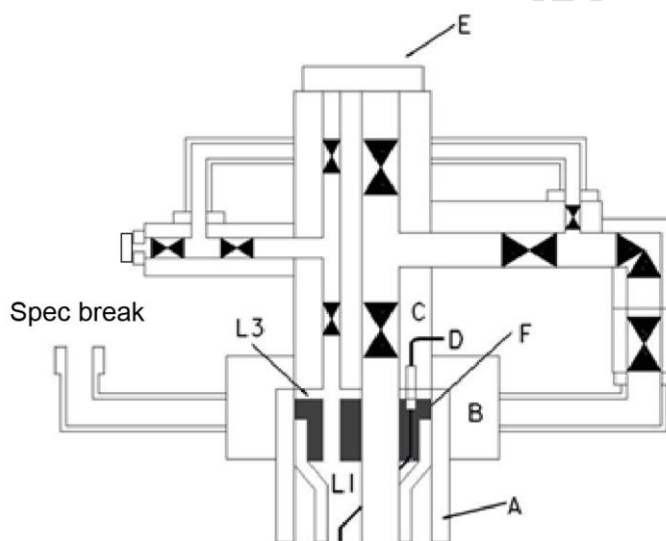
~~MIL-STD 120, Gage Inspection~~

~~MSS SP 55¹², Quality Standard for Steel Castings for Valves, Flanges and Fittings and Other Piping Components—Visual Method for Evaluation of Surface Irregularities~~

~~SAE/AS 568, Aerospace Size Standard for O-Rings~~

~~UL 746B¹³, Polymeric Materials—Long Term Property Evaluations~~

a) Vertical Subsea Tree



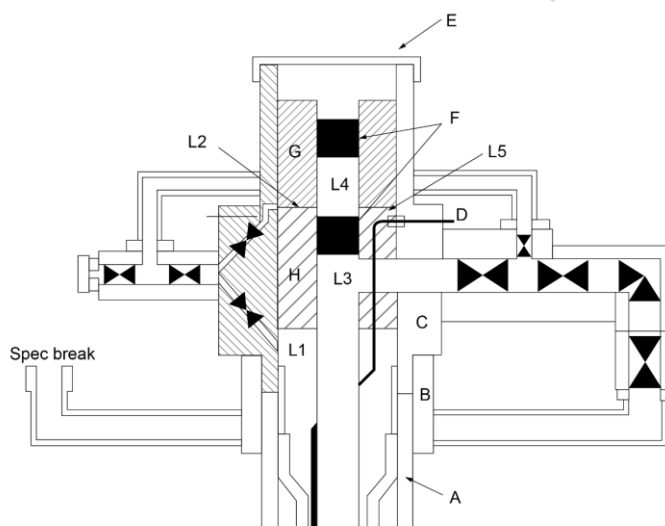
Position	Description	Working Test Pressure	Hydrostatic Body Test Pressure	Lockdown Retention Test Pressure
A	Subsea wellhead	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
B	Tubing head connector, tubing head, and tree connector	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
C	Valves, valve block	$1.0 \times \text{RWP}$	$1.5 \times \text{RWP}$	NA
D	Downhole flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-containing)	$1.0 \times \text{RWP-SB}$	$1.5 \times \text{RWP-SB}$	NA

¹⁴—~~Parts 1 and 2, Thermoplastics and Elastomers, have been published. Parts 3 to 5 are under development.~~

¹²—~~Manufacturers Standardization Society, 127 Park St. NE, Vienna, Virginia 22180, <http://msshq.org>.~~

¹³—~~UL, 333 Pfingsten Road, Northbrook, Illinois 60062, <https://www.ul.com>.~~

	Downhole flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-controlling)	1.0 × RWP-SB	1.0 × RWP-SB	NA
E	Tree cap (flow passages below tree cap and lock mechanism)	1.0 × RWP	1.5 × RWP	NA
F	Tubing hanger	1.0 × RWP	1.5 × RWP	NA
L1	Below installed tubing hanger	NA	NA	1.1 × RWP
L2 (not shown)	Above tubing hanger plug	NA	NA	1.0 × RWP
	Below tubing hanger plug	NA	NA	1.1 × RWP
L3	Gallery	1.0 × RWP-SB	NA	NA

b) Horizontal Subsea Tree with Separate Internal Tree Cap


Position	Description	Working Test Pressure	Hydrostatic Body Test Pressure	Lockdown Retention Test Pressure
A	Subsea wellhead	1.0 × RWP	1.5 × RWP	NA
B	Tree connector	1.0 × RWP	1.5 × RWP	NA
C	Valves, valve block	1.0 × RWP	1.5 × RWP	NA
D	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-containing)	1.0 × RWP-SB	1.5 × RWP-SB	NA
	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-controlling)	1.0 × RWP-SB	1.0 × RWP-SB	NA

	SCSSV flow passages and seal subs (SCSSV, other hydraulic, injection) (pressure-controlling)	1.0 × RWP-SB	1.0 × RWP-SB	NA
E	Debris cap	PMR	PMR	NA
F	Crown plugs	1.0 × RWP	1.5 × RWP	NA
G	ROV tree cap	PMR	PMR	NA
H	Tubing hanger	1.0 × RWP	1.5 × RWP	NA
L1	Below installed tubing hanger	NA	NA	1.5 × RWP
L2	Above lower crown plug	NA	NA	1.0 × RWP
	Below lower crown plug	NA	NA	1.5 × RWP
L3	Above upper crown plug	NA	NA	1.0 × RWP
	Below upper crown plug ^a	NA	NA	1.5 × RWP
L4	Gallery	1.0 × RWP-SB	NA	NA

^a If a lower crown plug is in place during the upper-crown-plug test from below, then the lower crown plug shall be pressure-equalized from above and below the lower crown plug during the test.

Section 7.1.3: Add the following note

NOTE: Manufacturer name and date of manufacture does not need to be included if already included elsewhere on the assembly.

Section 7.9.1: Paragraph 3 updated to the following:

Stab subs and seal subs in the production and annulus bore should conform to standard maximum pressure ratings of 5000 psi (34.5 Mpa), 10,000 psi (69 Mpa), or 15,000 psi (103.5 Mpa) as covered by this specification. The effects of pressure acting externally on stabs and seal subs shall be addressed up to the tree pressure rating, pressure rating of any seal sub in the annulus envelope outside the seal stab, or the hyperbaric pressure rating, whichever is greatest. Stab subs or seal subs used to conduct SCSSV control fluid, other hydraulic fluids, or injected chemicals shall be rated to a working pressure (RWP-SB) equal to or greater than the SCSSV control pressure or injection pressure, respectively, whichever is the higher, and be limited to 2500 psi (17.2 Mpa) plus the RWP of the tree.

Section 7.10.6.1.2: Paragraph 2 updated to the following:

The USV shall be of a fail-close design. The USV shall be designed to operate, without damage to the valve or actuator, when the valve is actuated open or closed, pressurized or depressurized, under any internal valve body pressure within its pressure rating, and under external pressure up to the maximum depth rating.

Section 7.10.6.1.3: Paragraph 1 updated to the following:

USVs shall satisfy the performance requirements specified in Section 5 and shall be validated as specified by API 6AV1 for the sandy service class designated by the manufacturer.

Section 7.10.6.1.3: Paragraph 3 updated to the following

An independent test agency, as defined by API 6AV1, shall conduct the API 6AV1 portion of USV validation and prepare the test report. The manufacturer shall submit a USV of the same basic design and materials

of construction for the API 6AV1 validation tests. An independent test agency is not required for other USV validation per Section 5.

Section 7.10.6.3: Update Title to the following

USV Factory Acceptance Testing

Section 7.16.6.3: Update section to the following:

All assembled USVs with USV actuators shall pass all applicable tests per API 17D as required in 7.10.4. All test data records shall be in accordance with 7.10.6.5.

Add the following Sections:

7.10.6.5 USV Records

Record requirements for USVs shall be in accordance with 5.4.1 with the following additional requirements

7.10.6.5.1 Shipping Report

The test agency and test report number for Class II or Class III safety valves shall be identified in the shipping report, as shown in the example of **Figure 1**. Other formats are acceptable, but they shall include the same information as a minimum.

USV Assembly Shipping Report	
USV Manufacturer _____	
Valve part no. or model _____	Serial no. _____
Size _____	Rated working pressure _____ PSL _____ Material class _____
Temperature class _____ or Temperature rating: Max. _____ Min. _____	
Service class _____	Test agency _____ Test report no. _____
Accepted by _____	Date of manufacture (month and year) _____
Actuator data: (circle type): Hydraulic Electric	
Manufacturer _____ Date of manufacture (month and year) _____	
Part/model no. _____	Serial no. _____ Size _____
Max. supply pressure rating _____ Temperature rating _____	
Accepted by _____	Date of manufacture (month and year) _____
'USV' valve and actuator assembly	
Assembler/manufacturer _____	
Assembly part no. or model _____	Serial no. _____
Accepted by _____	Date of manufacture (month and year) _____

Figure 1--- Example of USV Shipping Report

7.10.6.5.2 Test Data Sheet

All test data shall be recorded on a test data sheet. An example is shown in **Figure 2**. Other formats to included applicable tests are acceptable, but they shall include the same information as a minimum.

USV Assembly Factory Acceptance Test Data Sheet			
USV Manufacturer _____			
Valve part no. or model _____		Serial no. _____	
Size _____		Rated working pressure _____	
PSL _____		Temperature class/rating _____	
Service class _____		Test agency _____	
		Test report no. _____	
Actuator data: (circle type): Hydraulic Electric / Manufacturer _____			
Part/model no. _____		Serial no. _____	
Max. supply pressure _____		Size _____	
		Temperature rating _____	
		PSL _____	
Actuator seal test: Performed by _____ Date _____			
At 20 % of supply pressure rating:			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
At 100 % of supply pressure rating:			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Actuator operational test: Performed by _____ Date _____			
Number of cycles completed _____		Comment (opt) _____	
Valve shell test: Performed by _____ Date _____			
Primary hold period:			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Secondary hold period:			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Valve seat test: Performed by _____ Date _____			
Primary hold period (Side A):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Secondary hold period (Side A):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Tertiary hold period (Side A):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Primary hold period (Side B):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Secondary hold period (Side B):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Tertiary hold period (Side B):			
Start time _____	Pressure at start _____	End time _____	Pressure at end _____
Certified by _____		Title _____	
Company _____		Date _____	

Figure 2--- Example of a USV Factory Acceptance Test Data Sheet

7.10.6.5.3 USV Records Furnished to Purchaser

The following shall be furnished to the purchaser for each valve:

- Completed functional test datasheet as specified in FIGURE 11;
- Shipping report in accordance with Figure 1;
- USV Operating manual shall be furnished to the purchaser;
- Assembly traceability records.

7.10.6.5.4 Minimum Contents of Manufacturer's USV Operating Manual

The design information for USVs shall include the following:

- Type, model and size for which the manual is applicable;
- Performance requirements for which these types, model and sizes are suitable;
- Temperature and working pressure ranges for which the unit(s) is designed;
- Drawing and illustrations giving dimensional data of unit(s), as required, for installation or operation;
- Assembly diagram showing individual parts in proper relationship top one another;
- Parts list.

7.10.6.5.5 Failure Reporting

NOTE: Failure reporting is an essential element of the US federal regulatory program covering gas and oil production in the Outer Continental Shelf of the Gulf of Mexico.

After receiving a failure report from the operator, the manufacturer of the USV equipment shall respond within 6 weeks of receipt, describing progress in the failure analysis. The manufacturer shall also notify the operator in writing of the results of the analysis and the corrective action.

If the failure analysis causes the equipment manufacturer to change the design, assembly, or operating procedures of a model of equipment, the manufacturer shall, within 30 days of such changes, report them in writing to all purchasers and known operators of equipment having potential problems.

Section 7.16.2.6: Update bullet 3 to the following

- Testing—All testing for inboard piping shall conform to the requirements in accordance with 5.4. All testing for outboard piping shall be in accordance with the specified piping code, or 5.4, whichever is appropriate.

Section 7.16.2.6: Update Bullet 4 to the following

- Materials—Materials for inboard piping shall conform to 5.2. Material for outboard piping and pipe fittings shall conform to the requirements of the specified piping code or 5.2, whichever is appropriate. For example, wall thickness calculated using ASME B31.3 requires the use of ASME B31.3 allowable material stresses.

Section 7.17.2.2: Update to the following

Flowline connectors shall have an RWP equal to the RWP of the tree. The design of the flowline connector shall be in accordance with API 17R and the stress allowables per 5.1 or the selected outboard piping code

with respect to movement and alignment conditions. Integral hydraulics shall be in accordance with API 17R and 5.4.7.

Section 7.19.2.6: Update paragraph 2 to the following

For a line that penetrates the wellbore (for example chemical injection):

Annex Q: Add New informative Annex

Subsea Wellhead Annulus Seal Qualification

For API Committee Work Only