

Specification for Subsea Wellhead and Tree Equipment

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Specification for Subsea Wellhead and Tree Equipment

1 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.

2 Normative References

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

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 B16.11 ¹, *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 D1414 ², *Standard Test Methods for Rubber O-Rings*

DNV-RP-B401 ³, *Cathodic Protection Design*

ISO 8501-1 ⁴, *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 AS4059 ⁶, *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*

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 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.

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**

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****CRA**

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**

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.

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**

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**

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)**

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**

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**

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**

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.

3.2 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
<i>BPVC</i>	<i>Boiler and Pressure Vessel Code</i>
BSL	bolting specification level
CGB	completion guidebase
CID	chemical injection—downhole
CIT	chemical injection—tree
CRA	corrosion-resistant alloy
CRM	corrosion-resistant material
C_v	flow coefficient (US customary units)
EDP	emergency disconnect package (see API 17G)
<i>EF</i>	enhancement factor
ER	equivalent round
FAT	factory acceptance test

FEA	finite element analysis
GRA	guidelineless re-entry assembly
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
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

4 Application, Service Conditions, and Production Specification Levels

4.1 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.

a) 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);
- 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).

b) 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.

c) 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.

d) 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;
- bore protectors and wear bushings.

e) Tubing hanger systems:

- tubing hangers (PSL 2, 3, 3G);
- running tools (PSL 2, 3).

f) 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.

4.2 Service Conditions

4.2.1 Pressure

For this specification, pressure measurements shall be gauge pressure.

4.2.2 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.

4.2.3 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).

4.3 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.

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.

5 Common System Requirements

5.1 Design and Performance Requirements

5.1.1 General

5.1.1.1 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.

5.1.1.2 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.

5.1.1.3 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:

- a) component validation to the required minimum temperature as specified in 5.1.7;

- b) 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;
- c) component validation to the standard operating temperature range combined with additional material documentation supporting suitability for operation at the transitional temperature range.

5.1.1.4 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
^a As defined by NACE MR0175/ISO 15156. ^b In accordance with NACE MR0175/ISO 15156. ^c CRA required on retained fluid wetted surfaces only; CRA cladding of low-alloy or stainless steel is permitted (see 5.3.3). ^d CRA as defined in 3.1.11. NACE MR0175/ISO 15156 definition of CRA does not apply.		

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).

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

5.1.1.5 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.

5.1.1.6 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).

5.1.1.7 Operating Force or Torque

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

5.1.2 Service Conditions

5.1.2.1 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.

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.			
^g 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 those 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.

5.1.2.2 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 in. (mm)	Rated Working Pressure psi (MPa)
API line pipe (sizes)	1/2 (12.7)	10,000 (69.0)
High-pressure connections	Test and gauge connector ports per API 6A	≥ 15,000 (103.5)

5.1.2.3 Temperature Ratings

5.1.2.3.1 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)].

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.

5.1.2.3.2 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.

5.1.2.3.3 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.

5.1.3 Design Methods and Criteria

5.1.3.1 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.

5.1.3.2 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.

5.1.3.3 Pressure-controlling Components

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

5.1.3.4 Pressure-containing Components

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

5.1.3.5 Bolting

5.1.3.5.1 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.

5.1.3.5.2 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
^a See API 6A for guidance on bolting material selection. ^b For 105 ksi (725 MPa) 0.2 % offset yield strength studs, bolts, or cap screws $\geq 2.5"$, the bolting material shall be ASTM A320/A320M L43. ^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.		

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).

5.1.3.5.3 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.

5.1.3.5.4 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).

5.1.3.5.5 Closure and Critical Bolting

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.

5.1.3.5.6 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.

5.1.3.6 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.

5.1.3.7 Design of Equipment for Lifting

5.1.3.7.1 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.

5.1.3.7.2 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.

5.1.3.7.3 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.

5.1.4 Miscellaneous Design Information

5.1.4.1 Tolerances

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

- a) The tolerance for dimensions with format X . X is ± 0.1 in. (X is ± 2.5 mm).
- b) The tolerance for dimensions with format X . XX is ± 0.02 in. (X . X is ± 0.5 mm).
- c) The tolerance for dimensions with format X . XXX is ± 0.005 in. (X . XX is ± 0.13 mm).
- d) Dimensions listed as $XXXX/YYYY$ are considered the maximum dimension ($XXXX$) and the minimum dimension ($YYYY$), overriding the nominal tolerances to accommodate certain geometries.

5.1.4.2 End and Outlet Bolting

5.1.4.2.1 Hole Alignment

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

5.1.4.2.2 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.

5.1.4.3 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.

5.1.4.4 Test, Vent, Injection, and Gauge Connections

5.1.4.4.1 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.

5.1.4.4.2 Test and Gauge Connection Ports

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

5.1.4.5 Coatings (External)

5.1.4.5.1 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.

5.1.4.5.2 Color Selection

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

5.1.4.6 Cathodic Protection

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.

5.1.4.7 Monitoring

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

5.1.5 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.

5.1.6 Design Review

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

5.1.7 Validation

5.1.7.1 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.

5.1.7.2 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.

5.1.7.3 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.

5.1.7.4 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.

5.1.7.5 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) ^c	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.			
^a Temperature cycles shall be in accordance with API 6A. ^b Before and after the pressure cycle test, a low-pressure, 300 psi ± 30 psi (2 MPa ± 0.2 MPa), leak-tightness test shall be performed. ^c Subsea wellhead running tools are not included. ^d A choke-actuator/operator cycle is defined as total choke stroke from full-open to full-close or full-close to full-open. ^e For PR1, per PMR. For PR2, refer to API 17TR7 (see 7.8.3.3). ^f Manual valves or manual chokes operated by an actuator shall be qualified as an actuated valve or actuated choke. ^g API ring joint gaskets are excluded from this requirement.			

5.1.7.6 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.

5.1.7.7 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.

5.1.7.8 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) 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.
- b) 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.
- c) Scaling may be used to verify the members of a product family in accordance with API 6A.

5.1.7.9 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.

5.2 Materials

5.2.1 General

5.2.1.1 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.

5.2.1.2 Heat Treatment and Qualification Test Coupons

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

5.2.2 Corrosion

5.2.2.1 Corrosion from Retained Fluids

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

5.2.2.2 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;
- crevice corrosion;
- dissimilar metals effects;
- cathodic protection effects;
- coatings.

5.3 Welding

5.3.1 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.

5.3.2 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.

5.3.3 Hardfacing and Overlays

5.3.3.1 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).

5.3.3.2 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.

5.4 Quality Control

5.4.1 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.

5.4.2 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).

5.4.3 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.

5.4.4 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.

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

5.4.5.1 Hydrostatic Pressure Testing

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.

5.4.5.2 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.

5.4.6 Additional Testing for PSL 3G Equipment

5.4.6.1 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.

5.4.6.2 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.

5.4.6.3 Gas Body Test for Assembled Equipment

The test shall be conducted under the following conditions.

- a) The test shall be conducted at ambient temperature.
- b) The test medium shall be nitrogen.
- c) 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.
- d) 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.
- e) 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.
- f) 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.

5.4.6.4 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.

- a) 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.
- b) The test shall be conducted at ambient temperatures.
- c) The test medium shall be nitrogen.
- d) 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.
- e) Testing shall consist of two, monitored holding periods.
- f) The primary test pressure shall equal RWP.
- g) The primary test monitored hold period shall be 15 minutes.
- h) The pressure shall be reduced to zero between the primary and secondary hold points, but not by opening the valve.
- i) The secondary test pressure shall be 300 psi $\pm$ 30 psi (2 MPa $\pm$ 0.2 MPa).
- j) The secondary test monitored hold period shall be 15 minutes; the upstream pressure is then vented to zero, but not by opening the valve.
- k) The valves shall be fully opened and fully closed between tests.
- l) Bidirectional valves shall be tested on the other side of the gate or plug using the same procedure.

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.

5.4.6.5 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.

5.4.7 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.

5.4.8 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 .

5.4.9 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.

5.5 Equipment Marking

5.5.1 General

Equipment shall be marked with the following minimum information:

- "API 17D";
- 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.

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.

5.5.3 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.

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.

5.6 Storing and Shipping

5.6.1 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.

5.6.2 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.

5.6.3 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.

5.6.4 Loose Seals and Ring Gaskets

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

5.6.5 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.

5.6.6 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.

5.6.7 Electrical/Electronic Systems

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

5.6.8 Shipments

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

5.6.9 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.

5.6.10 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.

6 General Design Requirements for Subsea Tree Systems

6.1 General

6.1.1 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.

6.1.2 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.

6.1.3 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.

6.1.4 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.

6.1.5 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.

6.2 Tubing Head and Tree Valving

6.2.1 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.

6.2.2 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.

6.2.3 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.

6.2.4 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.

6.2.5 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.

6.2.6 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.

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.

6.2.7 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.

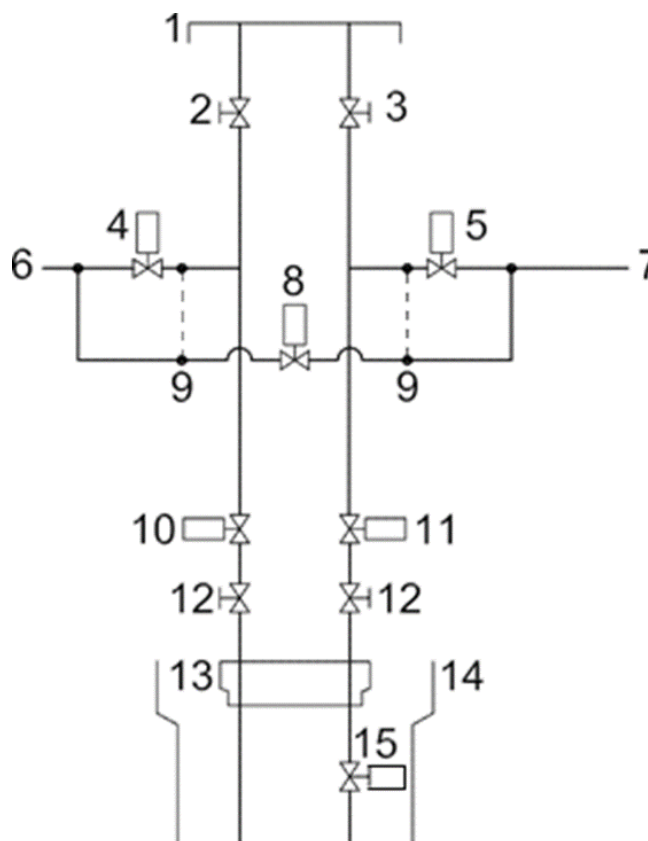
6.2.8 Production (Injection) and Annulus Flow Paths

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.

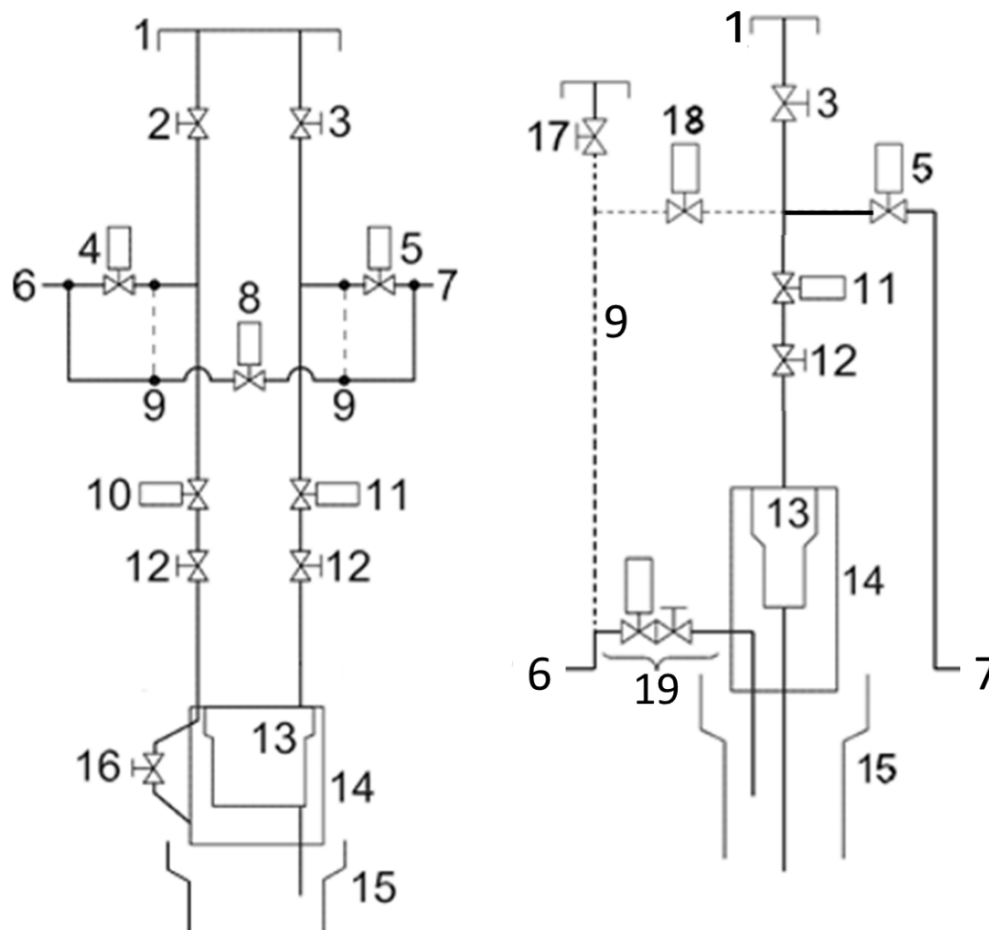
NOTE A schematic for a typical vertical dual-bore subsea tree is illustrated in Figure 1. Figure 2 illustrates vertical trees with tubing heads. Figure 3 illustrates horizontal subsea trees.

**Key**

- | | |
|---|--|
| 1 tree cap (swab closure) | 9 optional crossover piping routing |
| 2 annulus swab valve (ASV) (manual or fail-closed or optional plug) | 10 AMV |
| 3 PSV (manual or fail-closed or optional plug) | 11 PMV |
| 4 annulus wing valve (AWV) | 12 optional lower master (manual or fail-closed) |
| 5 production wing valve (PWV) | 13 tubing hanger |
| 6 annulus (to umbilical line or service line) | 14 subsea wellhead |
| 7 production | 15 SCSSV |
| 8 XO | |

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

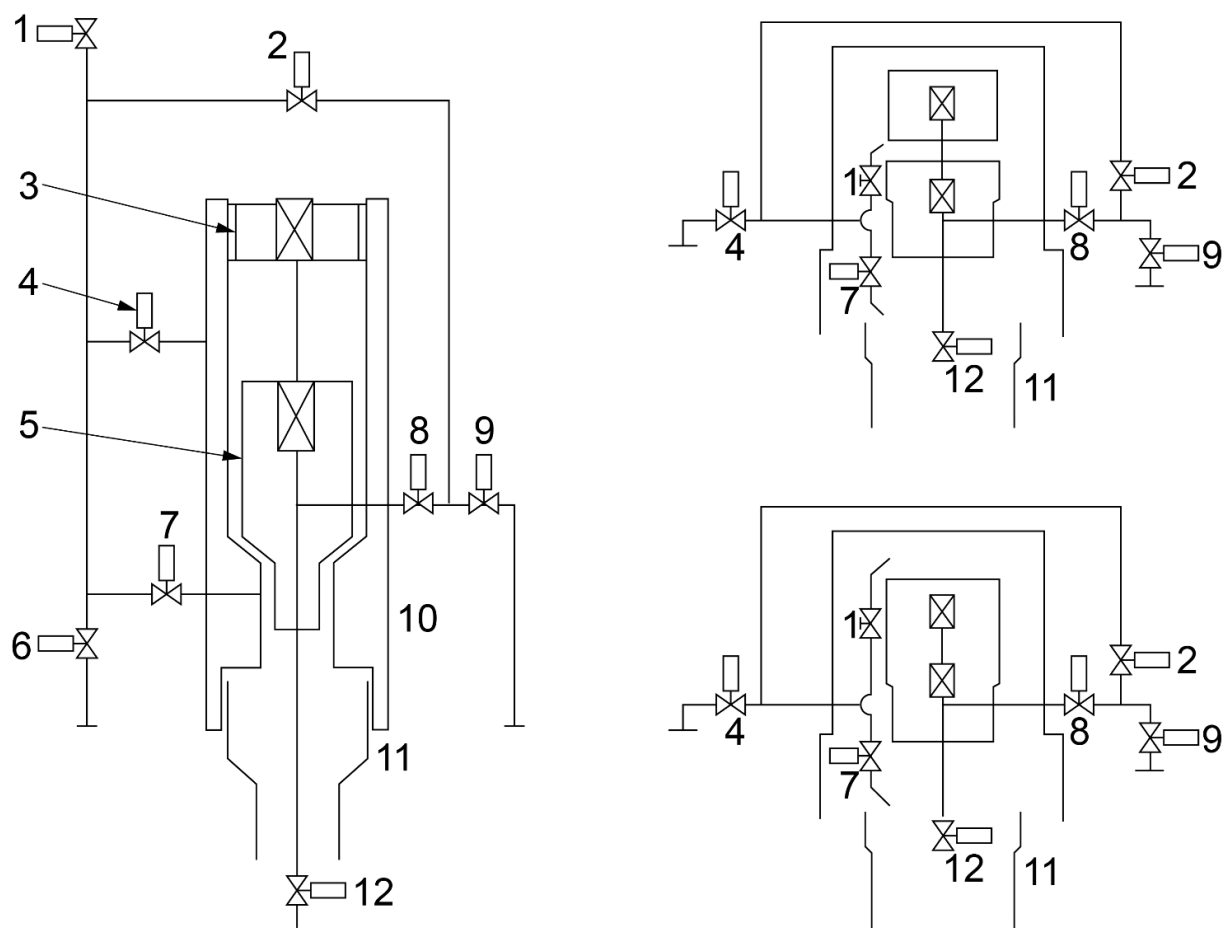


Key

- | | |
|--|--|
| 1 tree cap (swab closure) | 11 PMV |
| 2 ASV (manual or fail-closed or optional plug) | 12 optional lower master (manual or fail-closed) |
| 3 PSV (manual or fail-closed or optional plug) | 13 tubing hanger |
| 4 AWW | 14 tubing head |
| 5 PWV | 15 subsea wellhead |
| 6 annulus (to umbilical line or service line) | 16 annulus isolation valve (AIV) |
| 7 production | 17 optional ASV (WVO or AAV) (manual or fail-closed) |
| 8 XO | 18 optional XO |
| 9 optional crossover piping routing | 19 annulus valves (manual and fail-closed or both fail-closed) |
| 10 AMV | |

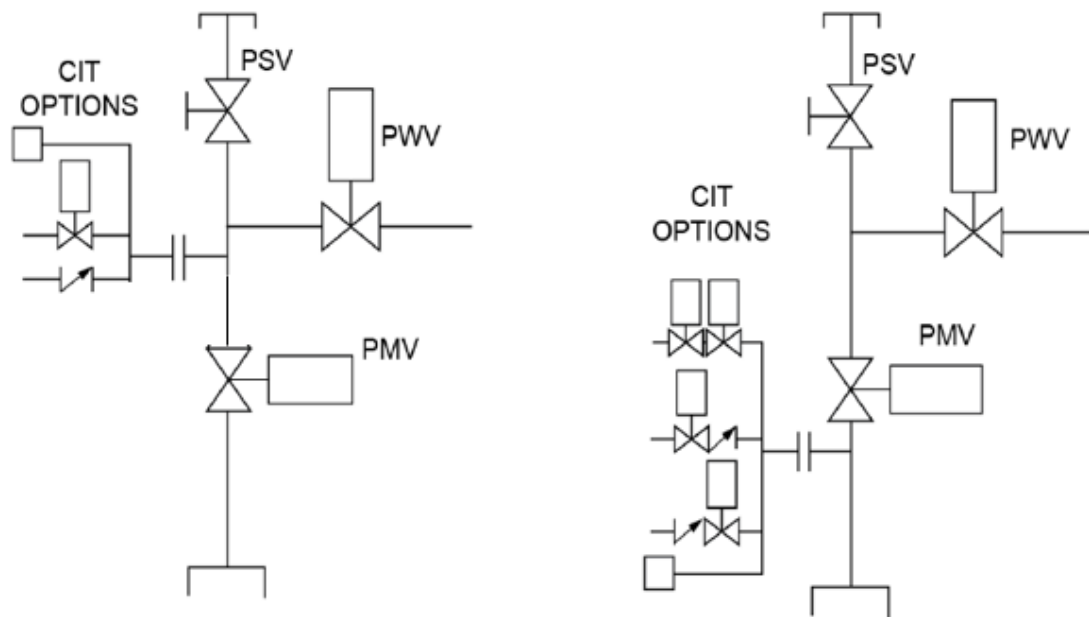
NOTE The dotted inclusions are optional. A non-pressure-containing tree cap can be considered when two swab closures are included.

Figure 2—Example of Vertical Trees on Tubing Heads

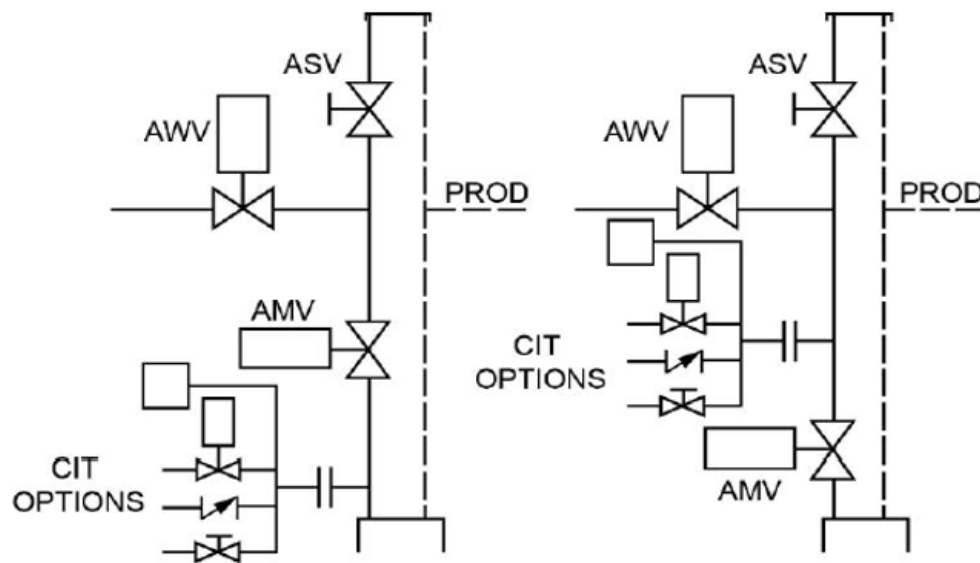
**Key**

- | | |
|--|--------------------|
| 1 ASV (WOV or AAV) (manual or fail-closed) | 7 AMV |
| 2 XOV | 8 PMV |
| 3 tree cap | 9 PWV |
| 4 AWV | 10 tree body |
| 5 tubing hanger | 11 subsea wellhead |
| 6 optional AWV | 12 SCSSV |

Figure 3—Examples of Horizontal Trees



a) Production Bore Penetrations



b) Annulus Bore Penetrations

Figure 4—Examples of Bore Penetrations