

Design and Manufacture of Subsea Well Intervention Equipment

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Introduction

This edition of API 17G has been updated and upgraded from a recommended practice to a standard. Its focus continues to be on through-BOP intervention riser system (TBIRS) and open-water intervention riser system (OWIRS). Its scope has been expanded to include the design and manufacture of components and equipment and the use of new technology. It also covers verification and validation, not only of components and equipment but also of subsea well intervention systems previously unrecognized by a specific standard.

This standard has been restructured to serve as the foundation for supplemental documents, so that similar hardware or practices may be recognized and referenced rather than repeating the information. To that end some of the equipment nomenclature mentioned in earlier editions of 17G has been changed to be more universal across more intervention methods. The supplemental documents that specifically address new subject areas of subsea well intervention will carry the 17G designation plus a numeric suffix (17G1, 17G2, etc.).

With the publishing of this document, the acronyms C/WO and CWOR have been discontinued. These terms have been replaced with through-BOP intervention riser system (TBIRS) and open-water intervention riser system (OWIRS), which are defined herein. Additionally, throughout the document, the term “riser or landing string” and “riser and landing string” are used and refer to OWIRS and TBIRS, respectively.

The overall objective of API 17G is to define auditable requirements that facilitate international standardization to enable safe and economic development of offshore oil and gas. It is intended for worldwide application in the petroleum industry. It is not intended to replace sound engineering judgment.

Users of API 17G should be aware that additional or different requirements may better suit the demands of a particular service environment, the regulations of a local authority, or other scenarios not specifically addressed here.

This standard is not intended to inhibit a manufacturer from offering, or the end user from accepting, alternative equipment or engineering solutions for the individual application. Where an alternative is offered, it is the responsibility of the manufacturer to identify any variations from this standard and provide details.

Finally, this standard is not intended to restrict or deter the development of new technology. Rather, it is intended to become the base standard from which new subsea well intervention technology can develop.

API 17G is an equipment/component-based standard. The supplemental documents to 17G will define system level requirements. It is important to note that manufacturers and integrators can design, manufacture, and supply individual equipment independent of overall system requirements. The end user or system integrator (on behalf of end user) is responsible for system engineering and for the system design and operation. System engineering should be conducted to ensure that subsea well intervention systems and their components are designed, manufactured, fabricated, operated, and maintained for their intended use, throughout their intended life.

The first of the supplement documents, API 17G1, defines system performance requirements and provides operational guidance for API 17G equipment. Operational guidance specifically includes barrier implementation and testing, equipment readiness and inspection, system monitoring and maintenance, and management of change.

Design and Manufacturing of Subsea Well Intervention Equipment

1 Scope

API 17G defines a minimum set of requirements for performance, design, materials, testing and inspection, hot forming, welding, marking, handling, storing, and shipping of new build subsea well intervention equipment [through-BOP intervention riser system (TBIRS) and open-water intervention riser system (OWIRS)] as defined herein.

The requirements in this standard apply to equipment whose rated working pressure (RWP) is less than or equal to 103.4 MPa (15,000 psi) or whose rated temperature is less than or equal to 177 °C (350 °F). Equipment ratings that exceed these limits are covered by this document and API 17TR8. For equipment whose ratings exceed the RWP of 103.4 MPa (15,000 psi) or the rated temperature of 177 °C (350 °F), API 17TR8 will take precedence in the event of conflicting requirements with this document.

Structural design methods and criteria given in API 17G are limited to components manufactured from materials that ensure ductile failure modes (e.g. carbon steels, low-alloy steels, and corrosion-resistant alloys). Components manufactured from materials that may not ensure ductile failure modes (e.g. composite materials, titanium, and titanium alloys) are beyond the scope of this standard.

Within this document, the following apply:

- all tables are normative, unless otherwise stated,
- all figures are typical and informative in nature,
- all instances of NOTE and EXAMPLE provide guidance and as such are typical and informative in nature.

The standard covers equipment that is connected to a fluid conduit tieback riser, either inside the marine riser (TBIRS) or open water (OWIRS). Intervention equipment such as riserless light well intervention systems, downline connected equipment, and remotely operated vehicle (ROV) intervention equipment are outside the scope of this standard.

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.

API Technical Report 5C3, *Calculating Performance Properties of Pipe Used as Casing or Tubing*

API Recommended Practice 5C5, *Procedures for Testing Casing and Tubing Connections*

API Specification 5CRA, *Specification for Corrosion-resistant Alloy Seamless Tubes for Use as Casing, Tubing, and Coupling Stock*

API Specification 5CT, *Specification for Casing and Tubing*

API Specification 5DP, *Specification for Drill Pipe*

API Specification 5L, *Specification for Line Pipe*, 45th Edition

API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*, 20th Edition

API Standard 6ACRA, *Age-hardened Nickel-based Alloys for Oil and Gas Drilling and Production Equipment*

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

API Recommended Practice 6HT, *Heat Treatment and Testing of Carbon and Low Alloy Steel Large Cross Section and Critical Section Components*

API Specification 7K, *Drilling and Well Servicing Equipment*

API Specification 8C, *Drilling and Production Hoisting Equipment (PSL 1 and PSL 2)*

API Specification 16A, *Specification for Drill-through Equipment*, 2004

API Specification 16C, *Choke and Kill Equipment*

API Recommended Practice 16ST, *Coiled Tubing Well Control Equipment Systems*

API Recommended Practice 17B, *Recommended Practice for Flexible Pipe*

API Specification 17D, *Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment*, Second Edition, 2011

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

API Specification 17L1, *Specification for Flexible Pipe Ancillary Equipment*

API Recommended Practice 17N, *Recommended Practice on Subsea Production System Reliability, Technical Risk, and Integrity Management*

API Recommended Practice 17Q, *Recommended Practice on Subsea Equipment Qualification*

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

API Technical Report 17TR8, *High-pressure High-temperature Design Guidelines*

API 17TR12, *Consideration of External Pressure in the Design and Pressure Rating of Subsea Equipment*

API Standard 18LCM, *Product Life Cycle Management System Requirements for the Petroleum and Natural Gas Industries*

API Specification 20B, *Open Die Shaped Forgings for Use in the Petroleum and Natural Gas Industry*

API Standard 20C, *Closed Die Forgings for Use in the Petroleum and Natural Gas Industry*

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*

API 579-1/ASME FFS-1, *Fitness-for-Service*

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

ANSI/ASME B18.2 ¹, *Square and Hexagon Bolts and Nuts*

ANSI/ASME B18.3, *Socket Cap, Shoulder, Set Screws, and Hex Keys*

ASME Boiler and Pressure Vessel Code (BPVC), Section V: *Nondestructive Examination*

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

ASME Boiler and Pressure Vessel Code (BPVC), Section VIII: *Pressure Vessels; Division 2: Alternative Rules*, 2015 Edition

ASME Boiler and Pressure Vessel Code (BPVC), Section VIII; *Division 3: Alternative Rules for Construction of High Pressure Vessels*

ASME Boiler and Pressure Vessel Code (BPVC), Section IX, *Welding and Brazing Qualifications*, 2015 Edition

ASNT ACCP-CP-1 ², *Central Certification Program Document CP-1*

ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing* (2011 Edition), and *ASNT Standard Topical Outlines for Qualification of Nondestructive Testing Personnel* (ANSI/ASNT CP-105-2011)

ASTM A370 ³, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products*, 2015 Edition

ASTM A388/A388M, *Standard Practice for Ultrasonic Examination of Steel Forgings*, 2015 Edition

ASTM A453/A453M, *Standard Specification for High-Temperature Bolting, with Expansion Coefficients Comparable to Austenitic Stainless Steels*, 2015 Edition

ASTM A923, *Standard Test Methods for Detecting Detrimental Intermetallic Phase in Duplex Austenitic/Ferritic Stainless Steels*, 2014 Edition

ASTM E10, *Standard Test Method for Brinell Hardness of Metallic Materials*

ASTM E18, *Standard Test Methods for Rockwell Hardness of Metallic Materials*

ASTM E21, *Standard Test Methods for Elevated Temperature Tension Tests of Metallic Materials*

ASTM E94, *Standard Guide for Radiographic Examination Using Industrial Radiographic Film*

ASTM E110, *Standard Test Method for Rockwell and Brinell Hardness of Metallic Materials by Portable Hardness Testers*

ASTM E140, *Standard Hardness Conversion Tables for Metals Relationship Among Brinell Hardness, Vickers Hardness, Rockwell Hardness, Superficial Hardness, Knoop Hardness, Scleroscope Hardness, and Leeb Hardness*

ASTM E384, *Standard Test Method for Microindentation Hardness of Materials*

¹ ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.

² American Society for Nondestructive Testing, 1711 Arlingate Lane, P.O. Box 28518, Columbus, Ohio 43228, www.asnt.org.

³ ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

ASTM E399, *Standard Test Method for Linear-Elastic Plane-Strain Fracture Toughness K_{Ic} of Metallic Materials*

ASTM E428, *Standard Practice for Fabrication and Control of Metal, Other than Aluminum, Reference Blocks Used in Electronic Testing*

ASTM E562, *Standard Test Method for Determining Volume Fraction by Systematic Manual Point Count*, 2011 Edition

ASTM E709, *Standard Guide for Magnetic Particle Testing*

ASTM G48, *Standard Test Methods for Pitting and Crevice Corrosion Resistance of Stainless Steels and Related Alloys by Use of Ferric Chloride Solution*, 2011 Edition (Includes all amendments and changes through Reapproval Notice, 2015)

AWS D1.1 ⁴, *Structural Welding Code—Steel*

BS 7448 ⁵, *Fracture mechanics toughness tests: Method for determination of K_{Ic} , critical CTOD and critical J values of metallic materials*

BS 7608, *Guide to fatigue design and assessment of steel products*, 2014 Edition (Includes all amendments and changes through Amendment 1, December 1, 2015)

BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*, 13th Edition (Includes all amendments and changes through CRGD, September 30, 2015)

DNVGL-RP-0034 ⁶, *Steel forgings for subsea applications*

DNVGL-RP-C203, *Fatigue design of offshore steel structures*

DNV-OS-F101, *Submarine Pipeline Systems*

DNV-RP-B401, *Cathodic Protection Design*

DNV-RP-F112, *Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection*

EN 1418 ⁷, *Welding personnel—Approval testing of welding operators for fusion welding and resistance weld setters for fully mechanized and automatic welding of metallic materials*, 1997 Edition

EN 10204:2004, *Metallic products—Types of inspection documents*

ISO 783:1999 ⁸, *Metallic materials—Tensile testing at elevated temperature* This standard has been revised by: ISO 6892-2:2011

ISO 3834-2:2005, *Quality requirements for fusion welding of metallic materials—Part 2: Comprehensive quality requirements*

⁴ American Welding Society, 8669 NW 36th Street, No. 130, Miami, Florida, 33166, www.aws.org.

⁵ British Standards Institution, Chiswick High Road, London, W4 4AL, United Kingdom, www.bsi-global.com.

⁶ DNV GL, Veritasveien 1, 1363 Hovik, Norway, www.dnvgl.com.

⁷ European Committee for Standardization (CEN-CENELEC), Avenue Marnix 17, B-1000 Brussels, Belgium, www.cen.eu.

⁸ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.

ISO 9606-1:2012, *Qualification testing of welders—Fusion welding—Part 1: Steels*

ISO 9712:2012, *Non-destructive testing—Qualification and certification of NDT personnel*

ISO 12107, *Metallic materials—Fatigue testing—Statistical planning and analysis of data*

ISO 12135:2002, *Metallic materials—Unified method of test for the determination of quasistatic fracture toughness*

ISO 14732:2013, *Welding personnel—Qualification testing of welding operators and weld setters for mechanized and automatic welding of metallic materials*

ISO 15156-1:2015, *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production—Part 1: General principles for selection of cracking-resistant materials*

ISO 15156-2:2015, *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production—Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons*

ISO 15156-3:2015, *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production—Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys*

ISO 15609-1:2004, *Specification and qualification of welding procedures for metallic materials—Welding procedure specification—Part 1: Arc welding*

ISO 15614-1:2004, *Specification and qualification of welding procedures for metallic materials—Welding procedure test—Part 1: Arc and gas welding of steels and arc welding of nickel and nickel alloys*

ISO 15614-7:2007, *Specification and qualification of welding procedures for metallic materials—Welding procedure test—Part 7: Overlay welding*

ISO 15653:2010, *Metallic materials—Method of test for the determination of quasistatic fracture toughness of welds*

NACE MR0175⁹, *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production*, 2015 Edition (Identical to ISO 15156-1:2015, ISO 15156-2:2015, ISO 15156-3:2015)

NACE TM0177-2005, *Laboratory testing of metals for resistance to sulfide stress cracking and stress corrosion cracking in H₂S environments*

SAE AMS 2750¹⁰, *Pyrometry*

⁹ NACE International, 15835 Park Ten Place, Houston, Texas 77084, www.nace.org.

¹⁰ SAE International, 400 Commonwealth Drive, Warrendale, Pennsylvania, 15096, www.sae.org.

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

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

3.1.1

auxiliary line

Conduit (excluding choke and kill lines) attached to the outside of the riser main pipe.

NOTE 1 The line is normally used for landing string circulation, riser circulation, tubing annulus circulation, tubing annulus pressurization, and well kill.

NOTE 2 Both the TBIRS and OWIRS may employ an auxiliary line.

3.1.2

barrier

Device or object that prevents flow across itself.

3.1.3

blowout preventer

BOP

Equipment installed on the wellhead or wellhead assemblies to contain wellbore fluids either in the annular space between the casing and the tubulars or in an open hole during well drilling, completion, and testing operations.

NOTE BOPs are not gate valves, workover/intervention control packages, subsea shut-in devices, well control components, intervention control packages, diverters, rotating heads, rotating circulating devices, capping stacks, snubbing or stripping packages, or non-sealing rams.

3.1.4

bolting

All-thread studs, tap-end studs, double-ended studs, headed bolts, cap screws, screws, and nuts.

3.1.5

BOP spacer joint/BOP spanner joint

Specialized riser joint assembly used when the landing string is deployed inside a drilling riser and subsea drilling BOP to install, retrieve, and orient a subsea tubing hanger.

3.1.6

critical bolting

Bolting used to assemble/join wellbore pressure-containing parts (including end and outlet connections) whose failure would result in a release of wellbore fluid to the environment.

NOTE Examples include flange bolting, bonnet bolting, end connection bolting on BOPs, ram door bolting, hub clamp bolting, studs and nuts on top of a hydraulic connector, and clamp bolts.

3.1.7

critical section

Section of the component whose material properties must meet the specified minimum mechanical strength and toughness requirements.

3.1.8

design life

Period for which subsea equipment can be used for its intended purpose with anticipated maintenance, but without substantial repair or replacement being necessary, including storage and working periods.

NOTE The design life includes the entire period from start of manufacture to termination of the subsea equipment.

3.1.9

design validation

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

NOTE Design validation can include one or more of the following (this is not an all-inclusive list):

- prototype tests;
- functional and/or operational tests of production products;
- tests specified by industry standards and/or regulatory requirements;
- field performance tests and reviews.

3.1.10

design verification

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

NOTE Design verification activities can include one or more of the following (this is not an all-inclusive list):

- confirming the accuracy of design results through the performance of alternative calculations,
- review of design output documents independent of activities of design and development,
- comparing new designs to similar proven designs.

3.1.11

extended factory acceptance testing

EFAT

Test conducted to verify that the specified requirements, for a set of interfacing products, have been fulfilled.

3.1.12

external loads

Loads that include global load effects like axial loads, bending moment, torque, and shear.

3.1.13

extreme load condition

Unavoidable but predictable load condition due to environmental and/or operating scenarios.

NOTE Extreme condition are defined as events with a probability less than 10^{-1} and larger than 10^{-2} based on appropriate risk assessment, for the period under consideration.

3.1.14

factory acceptance test

FAT

Test conducted by the original equipment manufacturer (OEM) to verify that the manufacture of specific equipment meets specified requirements.

3.1.15

fail-close

FC

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

3.1.16**fail-in-place****FIP**

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

3.1.17**fail-open**

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

3.1.18**function load capacity**

Minimum capacity of relevant functional failure modes, i.e. minimum of preload exceedance, seal/gasket leak tightness, loss of functionality due to permanent deformations, etc.

NOTE "Leak tightness" is a generic term used to describe non-exceedance of specific leak acceptance criteria.

3.1.19**global riser analysis****GRA**

Analysis of the complete subsea well intervention system from below mudline to traveling block, including tensioner joint, using beam elements.

NOTE Bending moments and effective tension distributions along the riser string due to functional loads, vessel motions, and environmental loads are determined by global riser analysis (GRA).

3.1.20**hangoff**

Riser when disconnected from seabed and suspended from a spider or other supporting mechanism designed to support the riser for an extended period of time.

3.1.21**landing string**

Jointed temporary riser used as part of the TBIRS that typically provides a conduit from the subsea test tree assembly (SSTTA) or BOP spanner joint to the surface tree and is typically used for well completion or intervention operations where hydrocarbons are expected.

NOTE A landing string may include pup joints, lubricator valve, cased wear joint, slick joints, and surface tree adapter joint.

3.1.22**lubricator valve**

Valve assembly situated below the surface tree and used to isolate the reservoir from the environment when deploying long WL/coiled tubing tool assemblies and to permit pressure testing of the upper portion of the landing string in the TBIRS or riser joints in the OWIRS.

3.1.23**mechanical disengagement**

Failure mode defined characterized by relative movement at the interface between two or more components.

NOTE This failure mode covers a variety of failure mechanisms, including:

- full or partial disengagement of threads;
- full or partial disengagement of load shoulders;
- back-driving of locking mechanisms.

3.1.24**minimum preload**

Minimum compression load between mating surfaces obtained at makeup including makeup scatter and permanent set.

3.1.25**normal class device**

Device not classified as safety class device.

NOTE The following devices may be included in the normal class:

- devices included in safety function sequences but are not required to achieve a safe-state condition;
- devices not included in safety functions.

3.1.26**normal load condition**

Regularly expected environmental and/or operational loading condition with a probability of occurrence greater than extreme condition based on appropriate risk assessment, for the period under consideration.

3.1.27**open-water intervention riser system****OWIRS**

Riser system that provides a conduit between the subsea well and the surface vessel that can be used for the installation and retrieval of subsea trees, well intervention, well tests, and flowbacks.

NOTE The OWIRS is run independently of the marine drilling riser and subsea BOP systems and incorporates its own well control features.

3.1.28**plastic collapse load**

Load that causes overall structural instability; the onset of gross plastic deformation.

3.1.29**preload exceedance**

Functional load capacity limit that defines the maximum load the connector can sustain before separation occurs.

NOTE 1 Separation is full mating surface separation such that no contact force exists across the surface (for tension and pressure). For bending, this is based on no contact force on a radial line drawn across the interface on the plane of maximum bending, typically from inside diameter (ID) to outside diameter (OD). This condition has particular relevance to fatigue performance.

NOTE 2 Preload exceedance may also be separation that is the start of detrimental relative movement/deflection that occurs at a key interface location such as gasket seal preps and thus may be significant to seal/gasket performance criteria. This may occur at the ID, even though no separation occurs at the OD. This condition has particular relevance to fretting.

3.1.30**pressure-containing part**

Part exposed to wellbore fluids whose failure to function as intended would result in a release of wellbore fluid to the environment.

EXAMPLES Bodies, bonnets, stems, seals.

NOTE Items that are not included are operating cylinders and cylinder heads.

3.1.31**pressure-controlling bolting (seawater exposed)**

Bolting used to assemble or join a pressure-controlling part exposed to seawater.

EXAMPLES Hydraulic system bolting, bolting securing actuator end caps.

3.1.32**pressure-controlling bolting (wellbore fluid exposed)**

Bolting used to assemble or join pressure-controlling parts exposed to wellbore fluids.

EXAMPLES Bolting attaching shear ram blade to ram block.

3.1.33**pressure-controlling part**

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

EXAMPLES Valve-bore sealing mechanism, and valve or ram actuation mechanism components, packing elements, rams, and replaceable seats within a pressure-containing part.

3.1.34**primary structural component**

Structural component in the system load path for which the design is largely dictated by the external loads.

3.1.35**product family**

Components that share the same design principles of physical configuration and functional operation utilizing the same criteria for design stress levels or structural capacities in relation to material mechanical properties.

3.1.36**qualification****qualified**

Process of confirming, by examination and provision of evidence, that equipment meets the specified requirements for the intended use; the combination of verification and validation activities.

3.1.37**redress**

Any activity involving the replacement of qualified parts.

3.1.38**retainer valve**

Valve assembly in the TBIRS or OWIRS used to retain fluid and prevents its escape to the environment during a riser disconnect operation.

3.1.39**riser diverter**

Integrated with the marine riser and uses a pressure-operated elastomeric annular bladder to create a seal on the landing string (TBIRS) or riser (OWIRS) sealing mandrel. Permits pressure control in the marine riser annulus and can divert marine riser fluid overflow to vent lines or drilling mud return system.

3.1.40**riser joint**

Joint consisting of a tubular member(s) midsection with riser connectors at the ends.

3.1.41**riser sealing mandrel**

Tubular element that protects the umbilical passing through its external surface and provides a smooth surface on to which the marine riser diverter preventer can seal.

3.1.42**running string**

Drill pipe running strings are typically used for installation/retrieval of subsea trees and upper well completions with no planned operations having hydrocarbons in the pipe.

3.1.43**safe-state**

Condition that exist when all safety class devices, defined by a safety function, have functioned as intended.

3.1.44**safety class device**

Device required to achieve a safe-state condition as a part of a safety function.

3.1.45**safety function**

Sequenced series of device actions intended to achieve a safe-state in relation to a specific hazardous event.

NOTE Safety functions for subsea well intervention systems typically include process shutdown (PSD), emergency shutdown (ESD), emergency quick disconnect (EQD), deadman, and autoshear.

3.1.46**service life**

Duration of time in which the equipment performs under the specified design conditions, i.e. time in active connected riser operations, excluding storage periods.

NOTE The service life is normally a small fraction of the design life.

3.1.47**slick joint**

Annular slick joint or ported annular slick joint included in SSTTAs or BOP spacer joints, around which either BOP pipe rams or BOP annular preventers can close and seal.

3.1.48**sour service**

Service conditions with H₂S content exceeding the minimum specified in NACE MR0175/ISO 15156 (all parts) at the design pressure.

3.1.49**spider**

Device, usually having retractable jaws or dogs, used to support the riser on the uppermost connector support shoulder during running of the riser.

3.1.50**stress joint**

Specialized riser joint, usually designed with a tapered cross section, to control curvature and reduce local bending stresses.

NOTE It is the lowermost riser joint in the riser string when configured for workover. A stress joint may also be used at the top of the workover riser string when operating conditions require it.

3.1.51**structural load capacity**

Minimum capacity of relevant structural failure modes, i.e. minimum of yielding, local failure, buckling, and mechanical disengagement.

3.1.52**subsea test tree****SSTT**

Part of the SSTTA, which isolates the well from the TBIRS with or without WL and coiled tubing present.

3.1.53**subsea test tree assembly****SSTTA**

Assembly of valves positioned above the tubing hanger running tool (THRT) located inside the subsea drilling BOP.

3.1.54**surface tree**

Device that provides flow control of the production and/or annulus bores during subsea installation or intervention operations.

3.1.55**surface tree adapter joint**

Crossover from the standard riser joint connector to the connection at the bottom of the surface tree.

3.1.56**survival load condition**

Load condition more severe than an extreme condition (which may be unplanned) in which equipment, after exposure, is required to maintain critical safety functionality.

NOTE Survival conditions are defined as events with a probability less than 10^{-2} and larger than 10^{-4} based on appropriate risk assessment, for the period under consideration.

3.1.57**system**

Collection of components assembled to perform a common function.

3.1.58**tension joint**

Special riser joint that provides a means for tensioning the OWIRS with the floating vessel's tensioner system.

3.1.59**tension ring**

Attachment point on the tension joint for the floating vessel tensioner system lines.

3.1.60**tensioner system**

Device that applies tension to the riser string while compensating for the relative vertical motion (stroke) between the (dynamic) floating vessel and the top of the (static) deployed riser string.

3.1.61**through-BOP intervention riser system****TBIRS**

Riser system that provides a conduit between the subsea well and the surface vessel that can be used for the installation and retrieval of the upper completion system, well intervention, well tests, and flowbacks.

NOTE The TBIRS is run inside of the marine drilling riser and subsea BOP system and may incorporate well control features in addition to those on the subsea BOP.

3.1.62**utility bolting**

Bolting that is required to mount equipment and accessories to the intervention equipment that is not critical or pressure controlling.

EXAMPLES Bolting on lifting eyes, pad eyes (non-welded), wear bushing, nameplate, clamps for tubing, guards.

3.1.63**well control device**

Component that can or may be used as a barrier.

NOTE 1 The designation of well control devices as barriers is outside the scope of API 17G.

NOTE 2 Barriers within the intervention system are defined by the end user.

3.1.64**well control package****WCP**

Portion of OWIRS that extends from the tree running tool (TRT) (bottom) to the emergency disconnect package (EDP) connector (top); purpose is to provide well and pressure control at the mudline directly above the wellhead.

3.2 Acronyms and Abbreviations

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

BM	base metal
BSL	bolting specification level
CAL	connection assessment level
CFD	computational fluid dynamics
CRA	corrosion-resistant alloy
CS/LAS	carbon steel/low-alloy steel
CT	coiled tubing
CTOD	crack tip opening displacement
C/WO	completion/workover
ECA	engineering critical assessment
EDP	emergency disconnect package
EFAT	extended factory acceptance testing
EQD	emergency quick disconnect
ESD	emergency shutdown
FAD	failure assessment diagram
FAT	factory acceptance testing

FC	fail-close
FEA	finite element analysis
FIP	fail-in-place
FMECA	failure mode, effects, and criticality analysis
GRA	global riser analysis
GTAW	gas tungsten arc welding
HAZOP	hazard and operability
HBN	Brinell hardness number
HIP	hot isostatic pressed
HPHT	high pressure high temperature
HRC	Rockwell hardness scale C
HS	high strength
HV	hardness Vickers
HXT	horizontal subsea christmas tree
ID	inside diameter
IP	internal pressure
IWOCS	intervention workover control system
LMRP	lower marine riser package
LP	low pressure
LRFD	load resistance factor design
LV	lubricator valve
LWRP	lower workover riser package
MDT	minimum design temperature
MOPFLPS	minimum operator pressure for low-pressure sealing
MPS	manufacturing procedure specification
MT	magnetic particle testing
MTBR	mean time between repair
NDE	nondestructive examination
NDT	nondestructive testing

NQT	normalize, quench, and temper
NQQT	normalized, double quench, and temper
NQTT	normalized, quenched, double tempered
OCTG	oil country tubular goods
OD	outer diameter
OEM	original equipment manufacturer
OWIRS	open-water intervention riser system
PH	precipitation hardenable
PIV	production isolation valve
PoD	probability of detection
PQR	procedure qualification record
PREN	pitting resistance equivalent number
PSD	process shutdown
PSL	product specification level
PT	penetrant testing
PWHT	postweld heat treatment
QQT	double quench and temper
QT	quenched and tempered
QTC	qualification test coupon
RAO	response amplitude operator
ROV	remotely operated vehicle
RWP	rated working pressure
SCF/d	standard cubic feet per day
SCSSV	surface controlled subsurface safety valve
SFC	steel forging class
SIT	system integration testing
SMAW	shielded metal arc welding
SMTS	specified minimum tensile strength
SMYS	specified minimum yield strength

SPWHT	simulated postweld heat treatment
SSC	sulfide stress cracking
SSL	service specification level
SSTT	subsea test tree
SSTTA	subsea test tree assembly
TBIRS	through-BOP intervention riser system
THRT	tubing hanger running tool
TRT	tree running tool
WCP	well control package
WL	wireline
WPS	welding procedure specification

3.3 Symbols

For the purposes of this document, the following symbols apply.

A_e	external cross section area of the pipe giving buoyancy if submerged
A_i	internal cross section area of the pipe that might be occupied by fluid content
A_p	cross-sectional area of the pipe
BTS	bending to stress factor
c	number of connector fatigue test results
D	specified OD
D_{max}	maximum inside or OD at any cross section;
D_{min}	minimum inside or OD at any cross section.
E	modulus of elasticity
F	fatigue test factor
F_d	design factor (inverse of safety factor)
f_{ERF}	environmental reduction factor
f_m	mean stress correction factor
f_x	notch support factor

f_0	initial pipe ovality
h	height difference between the actual location and the internal pressure reference point
$\ln$	natural log
$\log \bar{a}$	intercept constant for the design S-N curve
$\log \bar{a}_{\Delta M}$	intercept constant for the design M-N curve
M	bending moment
M-N	bending moment range vs number of cycles to fatigue failure
M_{bm}	applied bending moment
M_c	single load bending moment capacity
M_p	yield bending moment capacity of a pipe
M_y	through the thickness yield bending moment capacity
m	inverse slope of S-N or M-N curve
N	number of cycles
P_{br}	average bearing stress
P_{bs}	primary bending stress
P_{id}	internal design pressure in the pipe or the RWP
P_l	local primary membrane stress
P_m	general membrane primary stress
P_{sh}	primary average shear stress
$p_{b,c}$	internal pressure yield capacity of a closed-end pipe for all D/t ratios and for an open-end pipe with $D/t < 3.1$
$p_{b,o}$	internal pressure yield capacity of an open-end pipe for $D/t \geq 3.1$
$p_{c,c}$	hoop buckling (external pressure only) capacity for of a closed-end pipe
$p_{c,o}$	external pressure capacity for an open-end pipe
p_e	external pressure to the pipe
p_{ed}	external design pressure or rated external pressure
p_{el}	external pressure elastic capacity of a pipe

p_i	internal pressure in the pipe
p_{int}	internal pressure
$p_{int,c}$	single load internal pressure capacity (closed-end)
$p_{i,ref}$	internal pressure at reference point
p_o	external pressure
$p_{o,c}$	single load external pressure capacity (closed-end)
$p_{p,c}$	external pressure yield capacity of a pipe
$p_{p,o}$	external pressure yield capacity of a pipe
$p_{y,ic}$	minimum pressure to initiate yielding on the inside of a closed-end pipe
$p_{y,io}$	minimum pressure to initiate yielding on the inside of an open-end pipe
Q_s	secondary stress
R	stress ratio
r	notch root radius
SCF	stress concentration factor
SD	standard deviation of $\log N$
S-N	stress range vs number of cycles to fatigue failure
T_c	single load axial tension capacity
T_e	effective tension in the pipe
T_{pc}	yield tension capacity of a pipe
T_w	true wall tension or the axial (material) tension in the pipe
t	wall thickness defined in Table 8
t_{ca}	corrosion/wear/erosion allowance
t_{fab}	absolute value of the negative tolerance taken from the material specification
t_{nom}	nominal or specified wall thickness
x	number of standard deviations
x_c	confidence level
Y	yield strength temperature de-rating factor

Y_u	tensile strength temperature de-rating factor
ΔM	bending moment range
ΔM_0	fatigue strength at 10^6 cycles
$\Delta \sigma$	local stress range
$(\Delta \sigma_{eq})_{P+Q}$	primary-plus-secondary von Mises stress range
$\Delta \sigma_x, \Delta \sigma_y, \Delta \sigma_z$	normal stress ranges in directions x, y, and z
$\Delta \bar{\sigma}$	fatigue stress range
$\Delta \tau_{xy}, \Delta \tau_{yz}, \Delta \tau_{zx}$	shear stress ranges
ε_{peq}	equivalent plastic strain
ρ_i	density of the internal fluid
σ_a	axial stress in the pipe wall
$(\sigma_{br})_{P+Q}$	average primary-plus-secondary bearing stress
σ_{eq}	von Mises equivalent stress
$(\sigma_{eq})_P$	primary membrane von Mises stress
$(\sigma_{eq})_{Pl}$	local primary membrane von Mises stress
$(\sigma_{eq})_{Pm}$	general primary membrane von Mises stress
σ_m	mean stress
σ_n	stress normal to anticipated fatigue crack growth path
σ_u	tensile strength at maximum design temperature
$\sigma_x, \sigma_y, \sigma_z$	normal stresses in directions x, y, and z
σ_y	strength at maximum design temperature
$(\tau_{sh})_{Pm}$	average primary shear stress
$\tau_{xy}, \tau_{yx}, \tau_{zx}$	shear stresses
ν	Poisson's ratio

4 Applicability and Functional Requirements

4.1 Purpose

Section 4 identifies equipment within the scope of the document and defines the functional requirements for the equipment used in a TBIRS and OWIRS.

The requirements for each equipment type are defined in terms of the equipment's function and system interfaces.

4.2 Equipment Scope

4.2.1 TBIRS

The list of TBIRS equipment includes:

- riser sealing mandrel;
- subsea test tree (SSTT) connectors/crossovers;
- ported annular slick joint;
- subsea test tree assembly (SSTTA):
 - retainer valve;
 - vent valve;
 - shear sub;
 - SSTT latch and latch receptacle;
 - upper SSTT valve;
 - lower SSTT valve;
 - ported BOP slick joint;
- chemical injection subs;
- THRT adapter or adjustable fluted hanger assembly.

4.2.2 OWIRS

The list of OWIRS equipment includes:

- tension joint;
- stress joint;
- EDP;
- retainer valve;
- well control package (WCP);
 - isolation valve;

- shearing/sealing ram/valve;
- TRT adapter.

4.2.3 Equipment Common to Both TBIRS and OWIRS

Equipment that is common to both through-BOP and open-water intervention operations includes:

- WL/CT adapters;
- surface tree tension frames;
- surface trees;
- swivels;
- quick connector;
- surface tree adapter joints;
- cased wear joints;
- riser joints;
- lubricator valves;
- safety joints;
- riser spiders and hangoff devices;
- handling, lifting, and test tools.

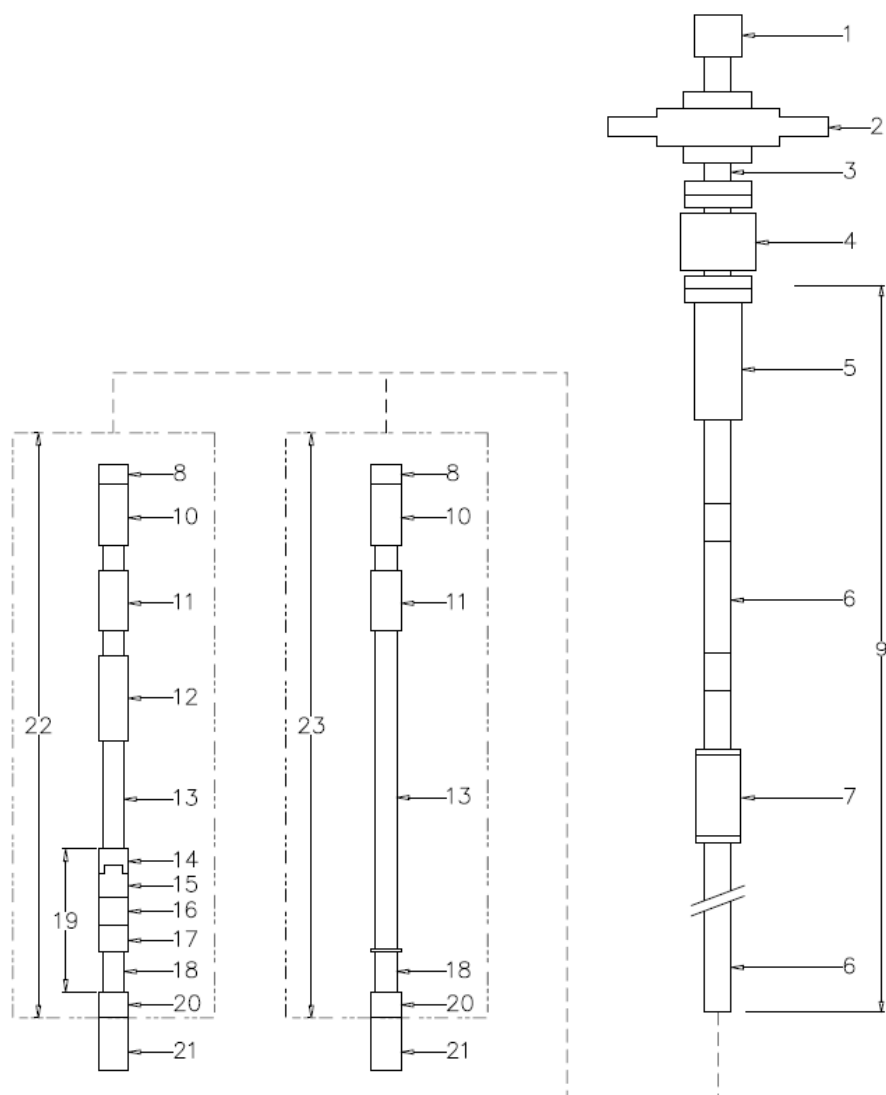
4.3 Nomenclature

Component nomenclature for a typical TBIRS is shown in Figure 1.

Component nomenclature for a typical OWIRS is shown in Figure 2.

Component nomenclature for a typical subsea well intervention system general arrangement in open-water intervention mode is shown in Figure 3.

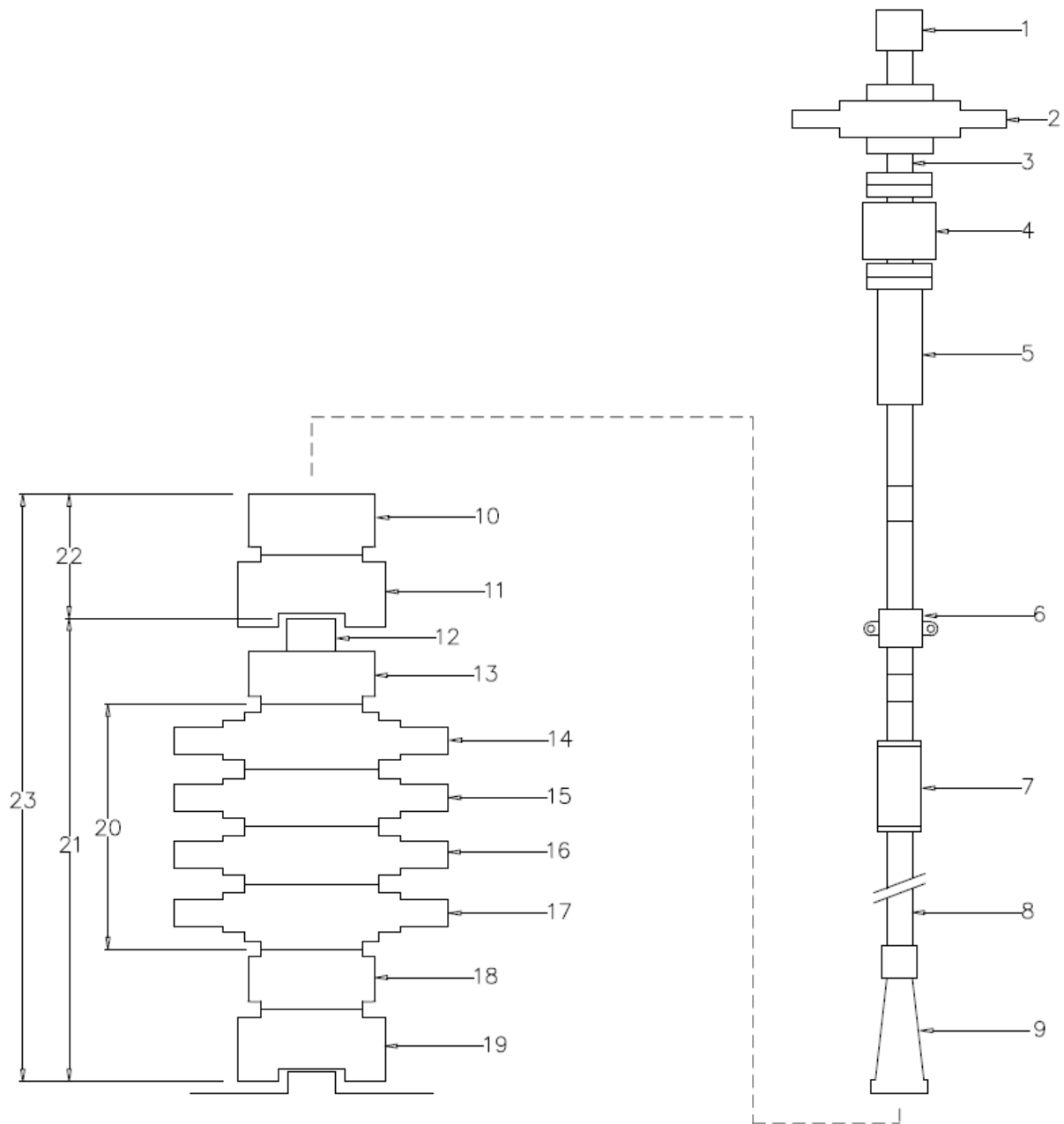
Component nomenclature for a typical subsea well intervention system general arrangement in through-BOP intervention mode is shown in Figure 4.



Key

- | | | |
|--|-------------------------------------|-----------------------------|
| 1 WL/CT adapter | 9 landing string | 17 lower SSTS valve |
| 2 surface tree | 10 upper ported annular slick joint | 18 ported BOP slick joint |
| 3 surface tree adapter joint | 11 lower ported annular slick joint | 19 SSTS |
| 4 swivel | 12 retainer valve | 20 THRT adapter |
| 5 cased wear joint/riser sealing mandrel | 13 shear sub | 21 THRT |
| 6 landing string joint(s) | 14 SSTS latch | 22 SSTS |
| 7 lubricator valve | 15 SSTS latch receptacle | 23 BOP spacer/spanner joint |
| 8 landing string adapter | 16 upper SSTS valve | |

Figure 1—Nomenclature for a Typical TBIRS

**Key**

1	WL/CT adapter	9	stress joint	17	lower ram
2	surface tree	10	retainer valve	18	TRT adapter
3	surface tree adapter joint	11	EDP connector	19	TRT/tree connector
4	swivel	12	EDP re-entry hub	20	shear/seal device(s)
5	cased wear joint	13	production isolation valve	21	WCP
6	tension joint	14	upper ram	22	EDP
7	lubricator valve	15	upper middle ram	23	LWRP
8	C/WO riser joint(s)	16	lower middle ram	24	C/WO riser

Figure 2—Nomenclature for a Typical OWIRS

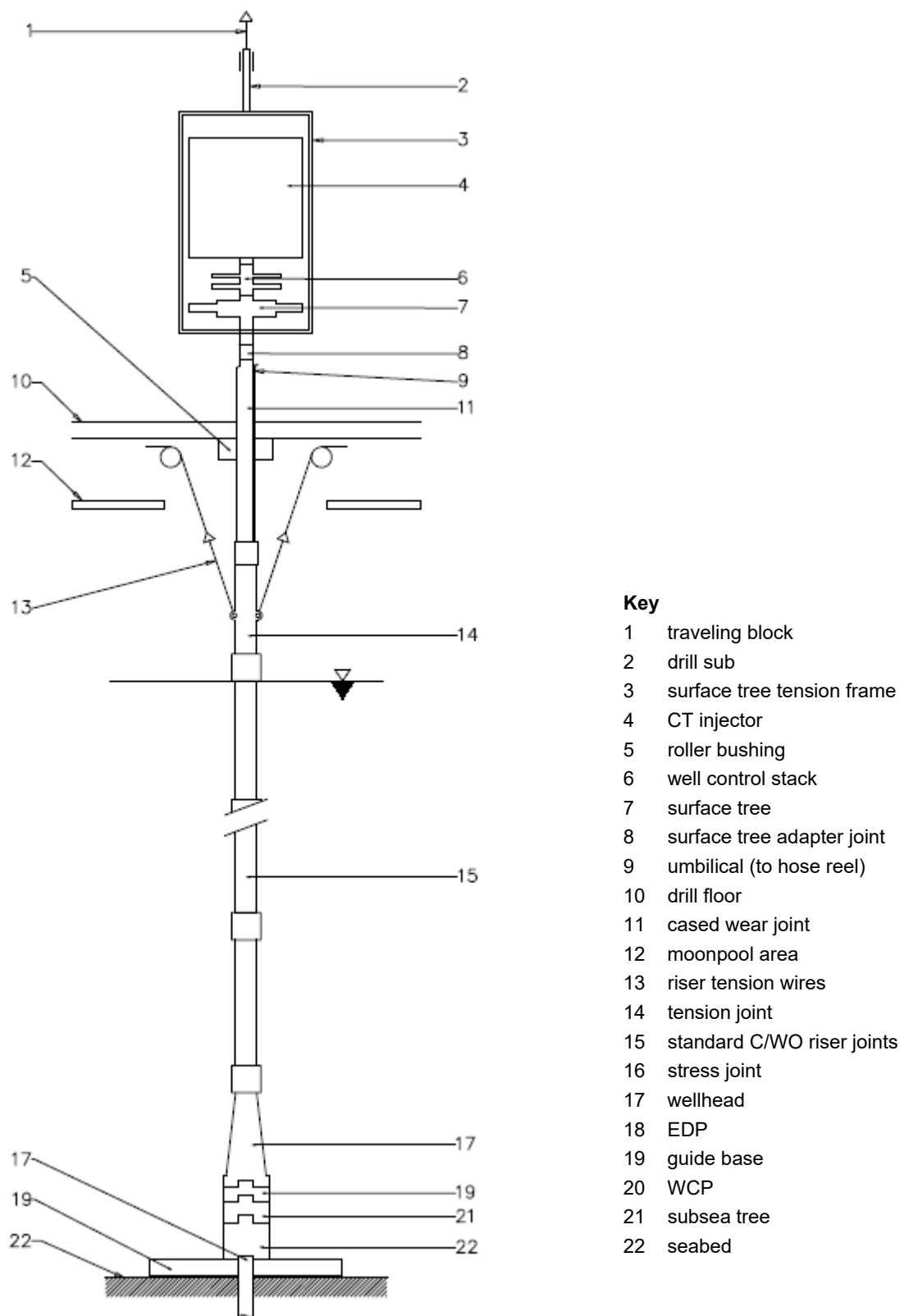


Figure 3—Typical Subsea Well Intervention System General Arrangement—Open-water Mode (Using OWIRS)

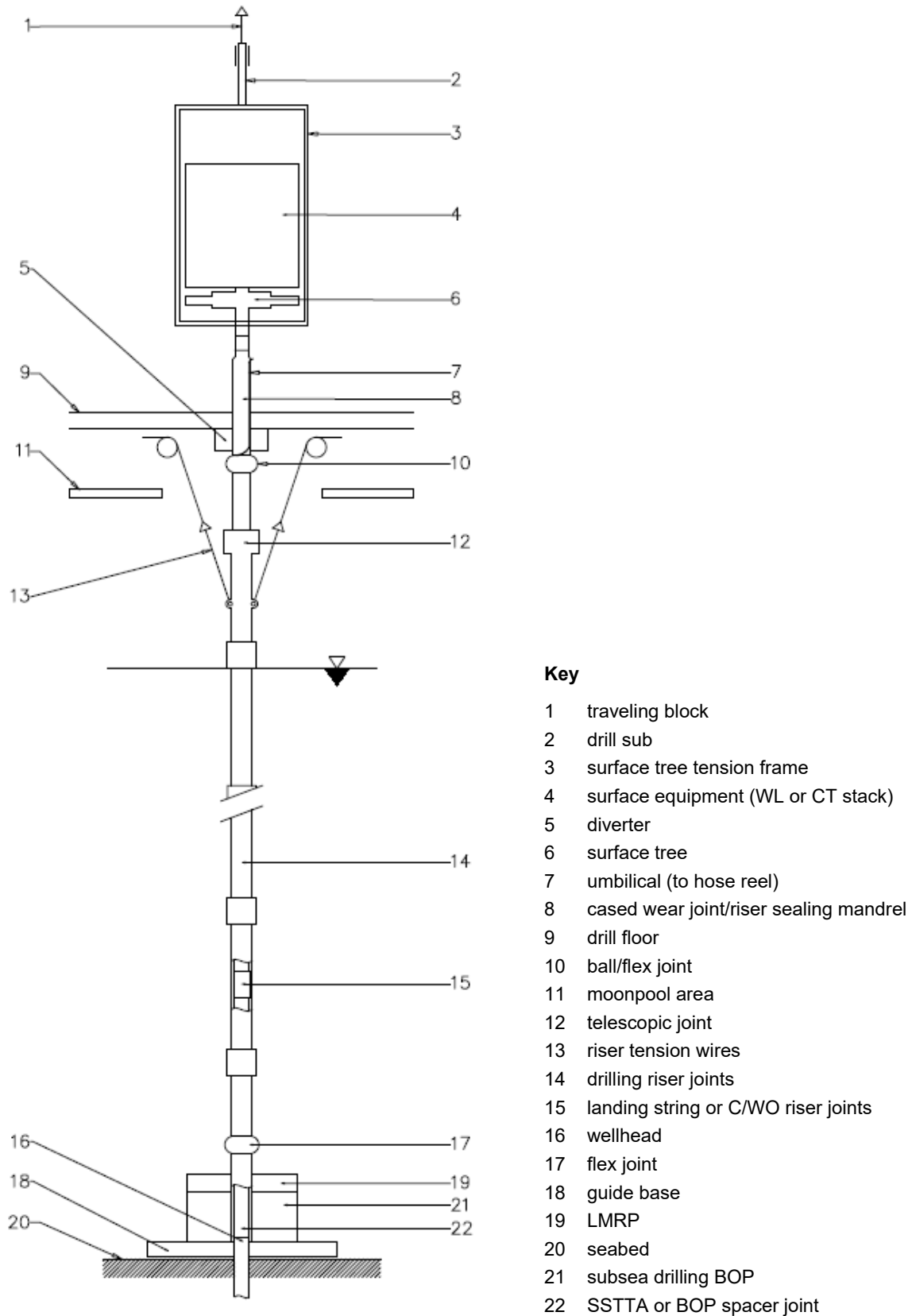


Figure 4—Typical Subsea Well Intervention System General Arrangement—Through-BOP Intervention Mode (Using TBIRS)



4.4 References, Codes, and Standards

Table 1 highlights the main subsea well intervention components included in the scope of API 17G with the applicable industry standards and sections of this document that are applicable.

Table 1—Equipment References, Codes, and Standards

Subsea Well Intervention Equipment	Functional Requirements	Design Requirements	Materials and Manufacturing Requirements	Validation Testing
Tubing hanger/THRT	API 17D	API 17D	API 17D	API 17D
THRT adapter	Section 4 and API 17D	Section 5 and API 17D	Section 6 and API 17D	API 17D and Section 5
Tubing hanger orientation system	Section 4	Section 5	Section 6	Section 5
BOP spacer joint	Section 4	Section 5	Section 6	Section 5
SSTT	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex G
SSTTA connectors and connections	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex E
Shear sub	Section 4	Section 5	Section 6	Section 5
Retainer valve	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex G or H
Lubricator valve	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex G
Chemical injection subs	Section 4	Section 5	Section 6	Section 5 and Annex G
Adjustable fluted hanger assembly	Section 4	Section 5	Section 6	Section 5
Riser sealing mandrel	Section 4	Section 5	Section 6	Section 5
LWRP (WCP/EDP)	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex H
EDP/LWRP/WCP connector	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex E
Riser joint connector	Section 4	Section 5 and Annexes C and D	Section 6	Section 5
Landing string joint connector	Section 4	Section 5 and Annexes C and D	Section 6	Section 5
Stress joint	Section 4	Section 5	Section 6	Section 5
Riser/landing string joints (OWIRS and TBIRS)	Section 4	Section 5	Section 6	Section 5
Tension joint	Section 4	Section 5	Section 6	Section 5
Cased wear joint	Section 4	Section 5	Section 6	Section 5
Surface tree adapter joint	Section 4	Section 5	Section 6	Section 5
Swivel	Section 4	Section 5 and Annexes C and D	Section 6	Section 5
Bore selectors	Section 4	Section 5	Section 6	Section 5
Surface tree	Section 4	Section 5 and Annexes C and D	Section 6	Section 5 and Annex H

Subsea Well Intervention Equipment	Functional Requirements	Design Requirements	Materials and Manufacturing Requirements	Validation Testing
WL/CT adapters	Section 4	Section 5	Section 6	Section 5
Surface tree tension frame	Section 4	Section 5 and API 8C	Section 6	Section 5 and API 8C
Riser spider	Section 4	Section 5 and API 7K	API 7K	API 7K
Handling tools	Section 4	Section 5 and API 8C	Section 6	Section 5 and API 8C
Auxiliary line	Section 4	Section 5 and API 16C, API 17B, and API 17L1	API 17B and API 17L1	Section 5

Any equipment or components of the subsea well intervention system that have not been designed, manufactured, and qualified in accordance with API 17G shall be documented by the manufacturer.

NOTE Safety joints/weak links are covered in Annex B.

4.5 Common Requirements

Requirements common to all equipment in the system are listed as follows:

- all outside surfaces of components shall be designed to provide for snag-free running and retrieval;
- inside surfaces of all vertical bores (including connection points) that require a tool to be passed through shall allow for free passage of drifts and tools;
- all safety class valves and rams shall be capable of closing and sealing under flow and pressure conditions;
- ROV interfaces shall conform to API 17H;
- all chemical injection (check) valves shall be validation tested for pressure rating, temperature rating, and flow capacity per Annex G.

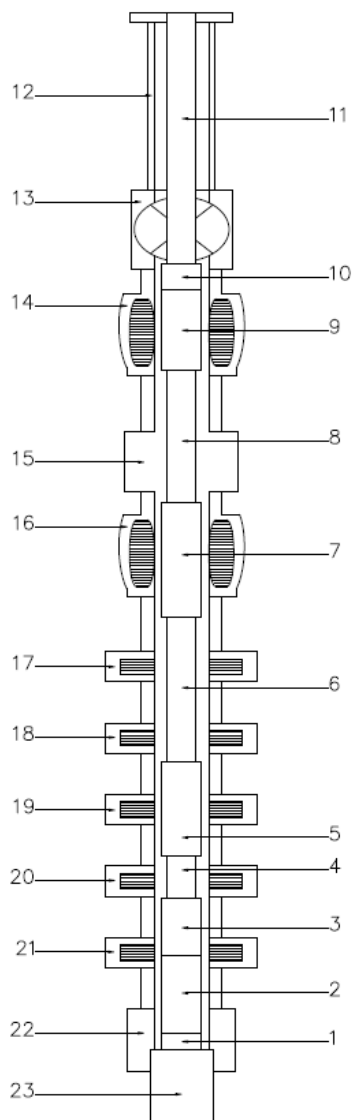
4.6 Tubing Hanger Orientation System

The tubing hanger orientation system provides correct tubing hanger orientation to allow makeup of the subsea tree and hydraulic/electrical/optical stabs as applicable. For more information on the tubing hanger orientation system, refer to API 17D.

4.7 BOP Spacer/Spanner Joint

The design of the BOP spacer/spanner joint provides well isolation by including the following components (refer to Figure 5):

- THRT adapter;
- ported BOP slick joint;
- shear sub;
- lower and/or upper annular slick joint;
- landing string adapter.



Key

1	tubing hanger	12	riser adapter
2	THRT	13	flex joint
3	THRT adapter	14	upper annular preventer
4	ported BOP slick joint	15	LMRP connector
5	tubing hanger orientation joint or pipe in pipe spacer or tubing hanger annulus access (orientation) joint	16	lower annular preventer
6	shear sub	17	upper shear ram
7	lower ported annular slick joint	18	lower shear ram
8	spacer sub	19	upper pipe ram
9	upper ported annular slick joint	20	middle pipe ram
10	landing string adapter	21	lower pipe ram
11	landing string joint	22	wellhead or HXT connector
		23	wellhead or HXT

Figure 5—Typical BOP Spacer Joint: Vertical and Horizontal Tree—Through-BOP Intervention Riser Mode

The following requirements for the BOP spacer/spanner joint shall apply.

- Permit orientation alignment to the tubing hanger.
- Permit pressure testing of the subsea drilling BOP, when installed within the bore of the subsea drilling BOP stack.
- Permit fluid access to the production tubing and the annulus between the production tubing and last casing string to allow pressure testing and fluid circulation.
- Provide the control line termination at its top and route all hydraulic/electrical lines to the equipment within the BOP spacer joint and tubing hanger as required by the system.
- Offer a means of disconnecting the BOP spacer/spanner joint/THRT from the tubing hanger.
- Provide a contingency method of disconnecting the BOP spacer joint THRT from the tubing hanger.
- Include anti-rotation feature at the internal and external interfaces to permit torque transfer during orientation of the tubing hanger and to prevent application of shear force to hydraulic stabs.
- Include a slick joint to allow for closure and sealing of a subsea drilling BOP pipe ram.
- The slick joint shall:
 - include a smooth external surface of a diameter corresponding to the subsea drilling BOP ram size to facilitate closure and sealing;
 - include a load shoulder at its lower end. The load shoulder reacting against the closed pipe ram shall prevent release of the SSTT in the event of an unintentional unlock of the THRT;
 - be provided with hydraulic/electrical/optical through porting as needed to facilitate control of necessary THRT/tubing hanger functions.
- The maximum anticipated rotation required for tubing hanger orientation and the torsional resistance of the downhole completion and landing string shall form the basis for determining requirements for torque capacity.
- Provide torsional resistance capacity accounting for static and dynamic effects (i.e. orientation at maximum landing speed).
- Requirement for installation of tubing hanger annulus crown plug is dependent on the design of the tubing hanger (e.g. with or without an annulus isolation valve). For a non-drift-able annulus bore, a contingency method for installation of tubing hanger annulus plug may be necessary to conform to barrier requirements.

4.8 Tubing Hanger Orientation Joint

The tubing hanger orientation joint is a specialized intervention riser component used to assist in the proper spatial orientation of the tubing hanger when not provided by the tubing hanger, THRT, wellhead, or subsea tree. It shall be designed to meet project-specific system requirements, particularly the subsea BOP dimensions.

The tubing hanger orientation joint shall:

- a) permit orientation alignment to the tubing hanger;

- b) include an orientation system to interface with the subsea drilling BOP orientation pin, where specified;
- c) include anti-rotation feature at internal and external interfaces to permit torque transfer during orientation of the tubing hanger.

4.9 SSTTA

The SSTTA typically includes the following components for all well and subsea tree types, which shall be defined in the end user for each system:

- annular slick joint;
- retainer valve;
- shear sub;
- SSTT;
- THRT adapter.

The SSTTA shall:

- allow for disconnecting the THRT from the tubing hanger;
- provide for installation and retrieval of the tubing hanger and production tubing during well TBIRS operations;
- allow for well testing; well servicing with WL, slickline, and CT; and well isolation during well intervention operations;
- permit orientation alignment of the tubing hanger, if required;
- provide a conduit from the bore of the tubing hanger to the landing string;
- permit fluid access to the production tubing to allow pressure testing and fluid circulation;
- permit fluid access to the annulus;
- include anti-rotation feature to permit torque transfer during orientation of the tubing hanger and to prevent application of shear force to hydraulic stabs;
- include a method to vent trapped pressure between the closed retainer valve and the shut in SSTT to the subsea drilling BOP/drilling riser before disconnection of the SSTT latch. If a vent valve is used, it shall meet the validation testing requirements of Annex G;
- incorporate safety features by either physical means or control system logic, to avoid unintentional activation of:
 - secondary functions;
 - SSTT unlatch and THRT unlatch during pre-deployment functional testing;
- have both primary and secondary functions for cutting and disconnect features;
- provide control-line termination at its top and routings for all hydraulic/electrical lines to the equipment within the SSTTA and tubing hanger as required by the system.

4.10 SSTT

NOTE The subsea test tree (SSTT) is a subset of the SSTTA consisting of a slick joint for sealing with the pipe rams of the BOP stack, two valves or sealing elements, and a disconnect mechanism (latch) for the TBIRS riser/landing string.

The following requirements shall apply:

- provide a means to isolate the well from the landing string by surface actuated command;
- provide a method of disconnecting and reconnecting the landing string above the point of isolation;
- consist of a minimum two remotely operated fail-close (FC) valves and the ability of cutting CT, slick line, or braided WL. Valves that are designated to cut and seal will be qualified in this manner;
- provide pump-through capability. Valves shall automatically reseal back to close upon pressure equalization;
- include a chemical injection line/port (if chemical injection is used) with a dual sealing/backflow valve arrangement;
- incorporate an interlock to prevent accidental unlatch:
 - the design shall require at least one valve to be closed, prior to unlatching the system;
 - the interlock shall be either physical or via control system logic;
 - it shall be possible to override the interlock at any time;
- include a ported BOP slick joint to allow for closure of a subsea drilling BOP pipe ram. The slick joint shall:
 - include a smooth external surface of a diameter corresponding to the subsea drilling BOP ram size to facilitate closure and sealing;
 - include a load shoulder at its lower end. The load shoulder reacting against the closed pipe ram shall prevent release of the SSTT in the event of an unintentional unlock of the THRT;
 - be provided with hydraulic/electrical/optical through porting as needed to facilitate control of necessary THRT/tubing hanger functions.

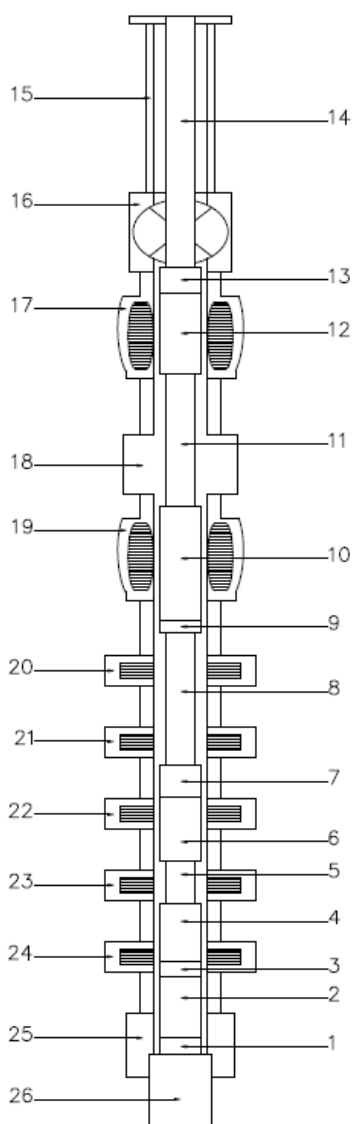
Within the SSTT, there shall be the capability of cutting CT, braided WL and slickline, and post shear seal in accordance with Annex G. The capability to cut CT, etc., shall be in the lowermost portion of the SSTT, unless a system analysis [failure mode, effects, and criticality analysis (FMECA) or hazard and operability (HAZOP)] concludes differently.

If no means to test the landing string is available once the SSTT is installed, then one SSTT valve shall be designed to retain RWP from above. Application of control-line pressure assist may be used to contain the pressure from above the valve.

Non-shear/seal-type valves should facilitate the removal of the cut media (e.g. stripping of CT, braided WL, and slickline) without compromising the sealing integrity.

Redundant seals (primary plus backup) shall be used between the production bore and the valve actuator chamber when the actuator chamber design RWP is less than the production bore pressure and nonmetallic seals are used.

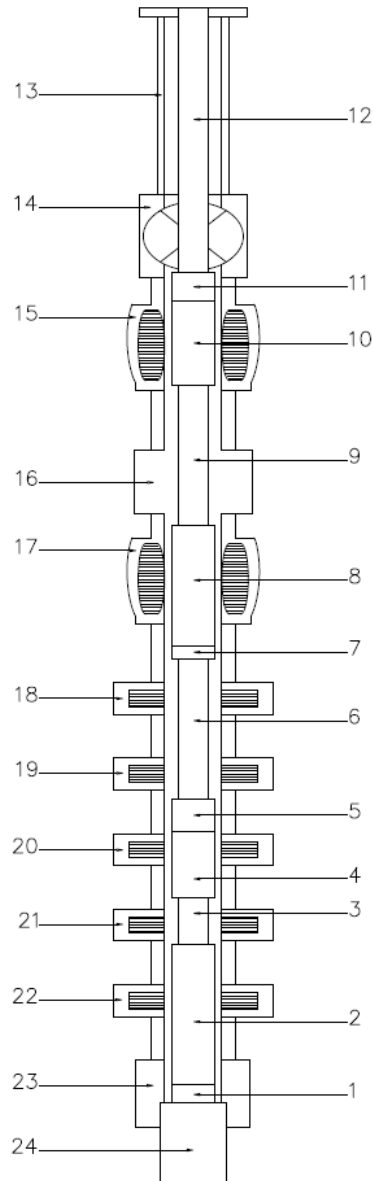
NOTE Figure 6 and Figure 7 are provided for reference.



Key

1	tubing hanger	14	landing string joint
2	THRT	15	riser adapter
3	tubing hanger orientation device	16	flex joint
4	THRT adapter	17	upper annular preventer
5	ported BOP slick joint	18	LMRP connector
6	upper and lower SSTT valves	19	lower annular preventer
7	SSTD latch	20	upper shear ram
8	shear sub	21	lower shear ram
9	vent valve	22	upper pipe ram
10	retainer valve	23	middle pipe ram
11	spacer sub	24	lower pipe ram
12	lubricator valve or ported annular slick joint	25	wellhead or HXT connector
13	landing string adapter	26	wellhead or HXT

Figure 6—Typical SSTTA with THRT—Through-BOP Intervention Mode

**Key**

1	adjustable fluted hanger assembly	13	riser adapter
2	lower SSTT valve	14	flex joint
3	ported BOP slick joint	15	upper annular preventer
4	upper SSTT valve	16	LMRP connector
5	SSTT latch	17	lower annular preventer
6	shear sub	18	upper shear ram
7	vent valve	19	lower shear ram
8	retainer valve	20	upper pipe ram
9	spacer sub	21	middle pipe ram
10	lubricator valve or ported annular slick joint	22	lower pipe ram
11	landing string adapter	23	wellhead connector
12	landing string joint	24	wellhead

Figure 7—Typical SSTTA with Fluted Hanger—Through-BOP Intervention Mode

4.11 SSTT Latch

NOTE The SSTT latch connects the SSTT to the landing string.

The SSTT latch shall:

- be positioned above the upper SSTT valve and below the subsea drilling BOP's blind shear ram to ensure that the BOP can isolate the well after the TBIRS riser/landing string disconnect;
- allow for remote makeup of the main bore and control lines and shall include full orientation before final connection;
- have an active positive latch function to be engaged during the entire operation;
- allow for status of hydraulic lines after disconnecting to be consistent with end user's safety function requirements (vented or blocked);
- permit pressure testing from above the closed SSTT valve to verify sealing integrity after makeup to SSTT;
- include a secondary means of retrieval after a shear of the shear sub;
- have the ability to disconnect under load capacities as specified by manufacturer or by agreement between manufacturer and purchaser at the time of enquiry and order.

4.12 Shear Sub

The following requirements for the shear sub shall apply:

- be located at a subsea drilling BOP shear ram elevation above the SSTT;
- be shearable by the subsea drilling BOP shear rams without damaging other components in the SSTTA or BOP spacer joint;
- allow for securing of hydraulic/electrical/optical lines along the length in a manner that ensures cutting by the shear ram and to prevent difficulties in engaging a fishing tool during recovery operations;
- be spaced out with sufficient length and clearance for the shear-affected zone of material near the shear plane to be entirely within shearable pipe body and not influenced by proximity to connectors or upsets on the shear sub.

4.13 Retainer Valve

4.13.1 General

NOTE The retainer valve is typically located at the bottom of either an open-water intervention mode (OWIRS) or through-BOP intervention riser mode (TBIRS) landing string.

The retainer valve shall be designed:

- with a RWP to retain full riser or landing string design pressure from above without the aid of control-line pressure;
- to be remotely operated, and either as "fail-in-place" or "fail-closed."

NOTE This may be accomplished by either physical means (e.g. springs) or through control system logic.

4.13.2 Retainer Valve/SSTTA—Through-BOP Intervention Riser Mode

For retainer valves/SSTTA used in through-BOP intervention riser mode, the following additional requirements shall apply.

- The retainer valve/SSTTA shall be designed to consider applicable external loading conditions associated with through-BOP riser mode operations.
- Redundant seals (primary plus backup) shall be used between the production bore and the valve actuator chamber, when the actuator chamber design RWP is less than the production bore pressure and nonmetallic seals are used.
- If the design also allows closure of the subsea drilling BOP annular preventer on the external surface, then the following shall apply:
 - a smooth external diameter to allow sealing of annular preventers;
 - capable of full functionality with the annular preventer closed.

4.13.3 Retainer Valve—Open-water Intervention Mode

For retainer valves used for open-water intervention, the following additional requirements shall apply.

- The retainer valve shall be designed for the applicable external loading conditions associated with an open-water environment.
- The design shall include a method to vent trapped pressure between the closed retainer valve and the shut-in WCP before disconnection of the EDP.
- Accommodate ROV override and visual position indicator.

4.14 Lubricator Valve

The lubricator valve shall be designed:

- with a RWP to retain full riser or landing string design pressure from below without the aid of control line pressure;
- with a RWP to retain full riser or landing string design pressure from above to permit pressure testing of the upper portion of the riser or landing string. Application of control-line pressure is permitted;
- to be remotely operated, fail-in place (FIP);
- with redundant seals (primary plus backup) between the production bore and the valve actuator chamber, when the actuator chamber design RWP is less than the production bore pressure and nonmetallic seals are used.

The lubricator valve may incorporate a chemical injection line/port, if included, it shall have a dual sealing/backflow valve arrangement.

When the lubricator valve is to be used for through-BOP intervention riser (TBIRS) mode, the lubricator valve:

- shall provide a pump-through capability;
- should be designed for installation below the inner barrel of the drilling riser telescopic joint (slip joint);

- should allow the bypass of the SSTTA and/or BOP spacer joint umbilical or other control lines in the marine riser unless the LV is located below these umbilical termination points.

When the lubricator valve is to be used for OWIRS mode, the lubricator valve shall be provided with one of the following options to allow well kill by bullheading in the event of control system failure:

- a pump-through capability;
- an isolated bypass line;
- an ROV override function.

4.15 SSTT Crossover

The SSTT crossover shall provide a mechanical and hydraulic interface from the SSTTA to the landing string.

4.16 Chemical Injection Sub

The chemical injection sub shall:

- provide a means for injection of chemicals into the landing string to assist in minimizing the risk of hydrate formation;
- include a chemical injection line/port with a dual sealing/backflow valve arrangement.

4.17 Ported Slick Joint

NOTE Ported slick joints may be used with either the subsea BOP annular preventer (ported annular slick joint) or BOP pipe ram preventer (ported BOP slick joint).

The ported slick joint shall:

- include a smooth external diameter to allow sealing of a subsea BOP preventer;
- be designed to withstand the combined loading of the closed preventer, compression forces, external pressure, and applicable external loading conditions;
- be provided with through porting (e.g. hydraulic and electrical) required for functions of equipment located below the slick joint.

4.18 THRT Adapter

The THRT adapter includes a lower interface compatible with the THRT, which is provided by the THRT provider or with an interface as specified by the end user. It also includes an upper interface compatible with the SSTTA and/or the BOP spacer joint.

The structural load capacity of the upper interface of the adapter shall be established as per this standard;

The structural load capacity of the lower interface of the adaptor shall be established as per API 17D. The THRT provider will provide the structural load capacity.

The THRT provider shall state if any component in the THRT limits the internal or external pressure rating of the THRT adaptor due to design or functionality.

4.19 Bore Selector

The following requirements shall apply for bore selectors. The bore selector shall:

- enable a means to divert from a monobore landing string or riser to a dual-bore (i.e. production and annulus bores) tubing hanger or subsea tree system;
- be able to select between bores to conduct operations;
- prevent inadvertent access to the non-operational bore;
- provide, where required, an external profile to facilitate sealing and or orientation depending upon the configuration.

4.20 Adjustable Fluted Hanger Assembly

The following requirements shall apply for adjustable fluted hanger assemblies. The adjustable fluted hanger shall:

- be designed to fit within the wellhead and land-out in the wear bushing, supporting the weight of the temporary completion;
- provide a means to adjust the set height of the fluted hanger to allow space-out of the SSTTA within the subsea drilling BOP;
- incorporate flutes or flow-by channels to permit circulation and annulus access.

NOTE The adjustable fluted hanger assembly is not to be confused with the permanent tubing hanger assembly whose requirements are defined in API 17D.

4.21 Lower Workover Riser Package (LWRP)

NOTE The LWRP is part of the OWIRS.

The following requirements apply to the LWRP.

- A LWRP may include an EDP and a WCP compatible with the subsea tree; see Figure 8 a) through Figure 8 e).
- The TRT when run as part of this system shall conform to the functional and structural requirements specified in this document.

NOTE The load histogram of a TRT used in an OWIRS is potentially more onerous than a TRT used for only running trees or tree connectors.

- The WCP upper re-entry spool interface with the EDP, or with a connection to mate with the lower end of the riser, shall have a defined minimum combined structural capacity to handle operations defined by the end user.
- The EDP or riser interfaces should include control line connections to interface with the WCP and the subsea tree, as required.
- Requirements for orientation and alignment should be designed and conform to the guidance provided in API 17D, as applicable. The manufacturer shall conduct a stack-up analysis and account for external influences, i.e. currents and riser offsets.
- Remotely operated annulus bore, main bore isolation valves/rams, and EDP and WCP connectors shall have a secondary means of operation/override.

- Other interfaces may be operated by a diver or ROV control function interfaces. The ROV interface shall conform with API 17H.
- The WCP may be configured as a single unit or a sectioned unit (see Figure 2 and Figure 3). In some instances, the WCP may be left behind to keep two barriers in place; keeping the well safe should well intervention be suspended for some extended period. The WCP portion left behind should be configured in such a way as its functions may be independently accessed by ROV hot stab (API 17H)/electric flying lead connections or an intervention workover control system (IWOCS).
- The LWRP should include a crossover loop between the riser tubing bores to allow circulation before subsea disconnection if required by the end user. If the crossover loop is in the LWRP, the crossover loop shall include an isolation valve.
- The LWRP should allow pressure testing of the riser to its disconnection points at the TRT and EDP.
- The following service condition classes and ratings shall apply for well control devices in the LWRP and shall be in accordance with the requirements of API 17G:
 - service specification level (i.e. SSL-liquid and SSL-gas);
 - pressure rating;
 - temperature rating;
 - service classification (i.e. safety class and normal class);
 - sandy service class (i.e. Sandy Class A, Sandy Class B, and Sandy Class C). See Annex A for sand slurry validation requirements.
- Shear class (i.e. WL, WL/CT class, and safety head class).
- All chemical injection lines shall include two FC valves to prevent backflow up the chemical injection line. Flow-closed check valves are acceptable as one of the FC valves, for lines with a diameter of 25.4 mm (1.00 in.) or smaller. At least one of the FC valves shall be an actuated FC valve. Chemical injection valves shall meet the requirements of this standard and also be designed for the required flow capacity.

4.22 EDP

The EDP shall allow for disconnect of the OWIRS.

NOTE The EDP may be located above subsea tree re-entry spool or above the WCP; refer to Figure 2, Item 22.

The following requirements shall apply:

- the EDP connector shall be capable of release while subjected to an applied bending moment and disconnect angle. The maximum disconnect angle shall be defined by the manufacturer or by agreement between manufacturer and purchaser at the time of enquiry and order;
- the maximum tension and bending moment at which the EDP is be capable of releasing shall be specified.

The EDP shall include the following:

- be capable of being disconnected and remotely installed on the subsea re-entry spool and be capable of performing a hydrostatic pressure test up to RWP;
- facilitate controls communication from the IWOCS umbilical to the subsea equipment, if applicable;
- include retainer valve functionality.

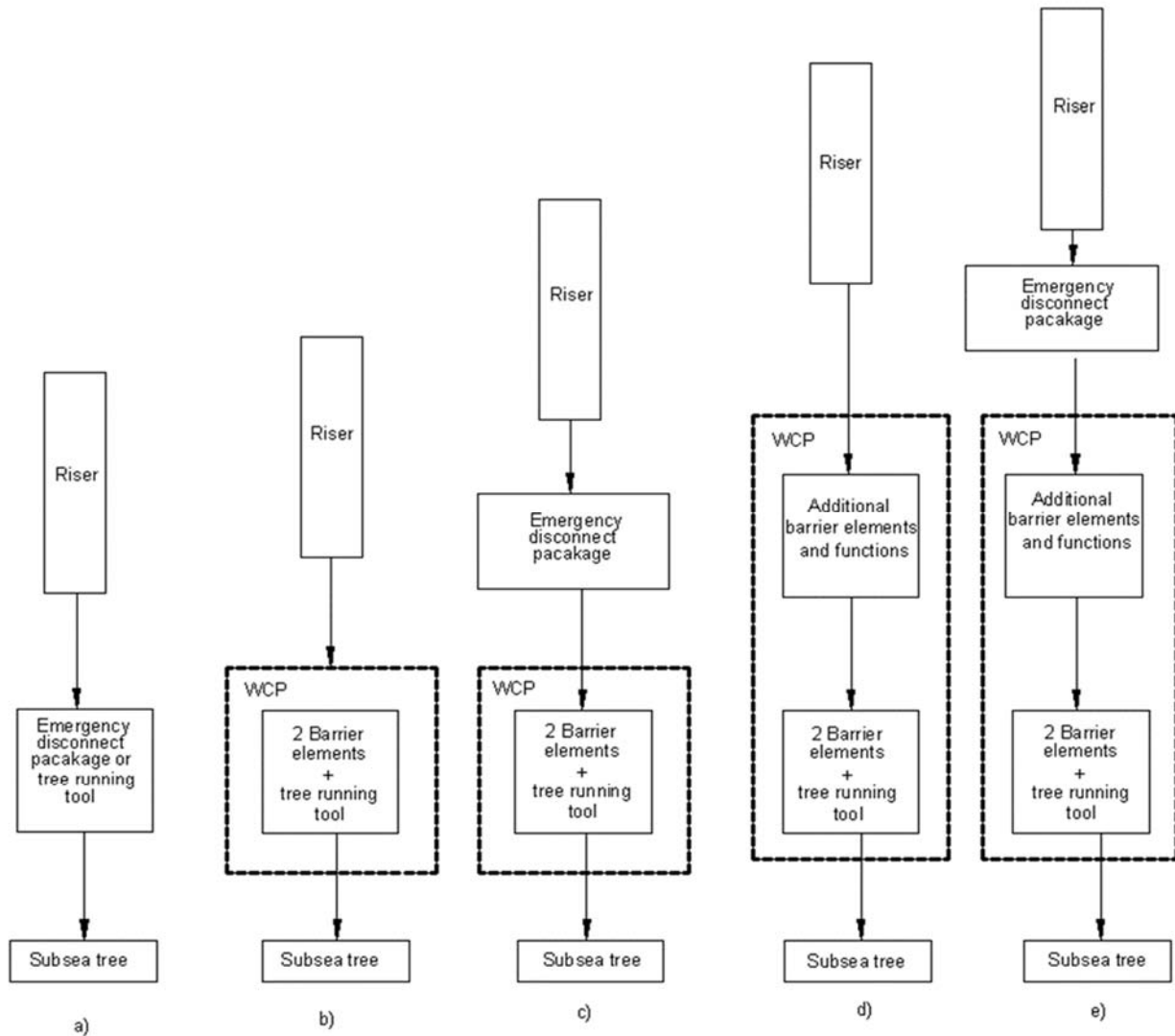


Figure 8—Typical LWPRP Interface Configurations

4.23 WCP

NOTE The WCP is part of the OWIRS.

The vertical through access bores in the WCP shall include a FC bidirectional isolation device in every through access bore and a FC shear/seal device in any bore with CT or WL equipment (or any other tool/device) in the bore.

NOTE FC functionality may be accomplished by means other than mechanical.

Selection of shear class (WL, WL/CT, safety head) should be based on the quantity and type of work strings in the vertical through access bore of the WCP.

A double shear device shall be designed to retain spent slugs.

The WCP shall have the ability to shear and seal at least 2 times without redress while maintaining the barriers as defined by the end user.

If there is requirement to hangoff the work string, then a slip ram can be included in WCP below the shear ram.

If there is a requirement to hangoff and seal well bore pressure, then a pipe-slip ram can be included in WCP below the shear ram.

If a slip ram or pipe-slip ram is included in the WCP, then:

- the distance between the shear ram and the slip ram or pipe-slip ram should allow fishing of trapped/suspended CT;
- the slip ram or pipe-slip ram shall centralize the CT.

If there is a requirement to circulate suspended CT following a subsea shear event:

- the shear ram shall be designed such that the orifice of the suspended sheared CT has sufficient flow area and the ram shear elements give fluid access to the coil after shearing and sealing;
- the pipe-slip ram shall have bi-directional gripping capabilities, minimum of full working pressure sealing from one direction, and be capable of suspending the full weight of the CT or pipe below the WCP and hold the CT in a pipe light situation at RWP. Provision should be made for circulation of the riser and circulation/bullheading of the production tubing via the annulus bore.

Safety class well control devices shall be capable of closing in the flowing direction under manufacturer's rated flow and pressure conditions.

If the WCP has methanol injection line/ports, they shall have a dual sealing/backflow valve arrangement.

The WCP shall provide a means to equalize pressure in the production bore across the lower well control device if the device is not designed to open under differential pressure.

Well control devices shall have position indicators observable by ROV/diver.

Rams with bidirectional hydraulic actuators shall include a mechanical locking system that is automatically actuated to prevent unintentional opening. The WCP should include a bypass line to allow for bullheading of the production tubing with the WCP well control devices in the closed position.

The WCP shall be designed to withstand installation of another intervention system, or removal from the well, during uncontrolled flowing conditions.

Figure 8 indicates examples of possible configurations of the WCP.

4.24 Connectors

4.24.1 General

Mechanical or hydraulic device used to connect adjacent components in the riser system to create a structural joint that resists applied loads and prevents leakage.

Connectors with multiple bores enclosed within an outer or secondary seal shall have seal systems to prevent cross-communication between individual bores.

Connector pressure separation loads and rated capacities shall be based on worst-case sealing conditions (i.e. leakage to the largest-diameter redundant seal shall be assumed, unless relief is provided).