# Design and Operation of Subsea Production Systems—General Requirements and Recommendations

API RECOMMENDED PRACTICE 17A
FIFTH EDITION, MAY 2017

AMERICAN PETROLEUM INSTITUTE

## Special Notes

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

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

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

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

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

## Foreword

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

Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the specification.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the specification.

This document was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 1220 L Street, NW, Washington, DC 20005. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 1220 L Street, NW, Washington, DC 20005.

Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

## Contents

## Contents

## Introduction

This document has been prepared to provide general requirements, recommendations, and overall guidance for the user to the various areas requiring consideration during development of a subsea production system for the petroleum and natural gas industry. The intention is to facilitate and complement the decision process rather than to replace individual engineering judgment and, where requirements are nonmandatory, to provide positive guidance for the selection of an optimum solution.

The development of this document is based on input from API Subcommittee 17 (Subsea Production Systems) technical experts. The technical revisions have been made in order to accommodate the needs of industry and to move this specification to a higher level of service to the petroleum and natural gas industry.

This document is not intended to inhibit a manufacturer from offering, or the purchaser from accepting, alternative equipment or engineering solutions for a specific application. This may be particularly applicable where there is innovative or developing technology.

Users should be aware that the current revision of this document no longer includes much material that was considered to be tutorial in nature. The majority of this material can now be found in API Technical Report 17TR13.

# Design and Operation of Subsea Production Systems—General Requirements and Recommendations

## 1 Scope

API 17A provides general requirements and recommendations for the development of subsea production systems, from the design phase to decommissioning and abandonment. This document also references to other API 17-series documents as well as various other relevant industry documents.

The complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a given processing facility located offshore (fixed, floating, or subsea) or onshore, or to inject water/gas through subsea wells.

This document, given its broad scope, has a systems engineering section. The purpose of this section is to help ensure consistency across the various subsystems.

If requirements as stated in this document are in conflict with, or are inconsistent with, requirements as stated in other API 17-series documents, then the specific requirements in the subsystems series document(s) take precedence.

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

API Recommended Practice 17C, *Recommended Practice on TFL (Through Flowline) Systems*

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

API Specification 17E, *Specification for Subsea Umbilicals*

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

API Recommended Practice 17G, *Recommended Practice for Completion/Workover Risers*

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

API Specification 17J, *Specification for Unbonded Flexible Pipe*

API Specification 17K, *Specification for Bonded Flexible Pipe*

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

API Recommended Practice 17L2, *Recommended Practice for Flexible Pipe Ancillary Equipment*

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

API Standard 17O, *Standard for Subsea High Integrity Pressure Protection Systems (HIPPS)*

API Recommended Practice 17P, *Design and Operation of Subsea Production Systems—Subsea Structures and Manifolds*

API Recommended Practice 17Q, *Subsea Equipment Qualification—Standardized Process for Documentation*

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

API Recommended Practice 17S, *Recommended Practice for the Design, Testing, and Operation of Subsea Multiphase Flow Meters*

API Recommended Practice 17U, *Recommended Practice for Wet and Dry Thermal Insulation of Subsea Flowlines and Equipment*

API Recommended Practice 17V, *Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications*

API Recommended Practice 17W, *Recommended Practice for Subsea Capping Stacks*

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

API Specification Q2, *Specification for Quality Management System Requirements for Service Supply Organizations for the Petroleum and Natural Gas Industries*

# 3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

## 3.1 Terms and Definitions

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

**3.1.1**
**extended factory acceptance test**
**EFAT**
Test conducted to verify that the specified requirements, for a set of interfacing products, have been fulfilled.

**3.1.2**
**interchangeability test**
**ICT**
Test conducted to verify the interchangeability requirements of “identical” products, which may be interfaced with other mating products at the installation site, have been fulfilled.

**3.1.3**
**life cycle**
That of a subsea development that includes design, manufacture through commissioning, operations, intervention, and decommissioning.

**3.1.4**
**predeployment test**
**PDT**
Test conducted to verify that the specified requirements, for a product that is ready for deployment, are still fulfilled.

**3.1.5**
**site received test**
**SRT**
Test conducted to verify that the specified requirements, for a product that has been transported from one site to another, are still fulfilled.

**3.1.6**
**system function test**
**SFT**
Test conducted to validate that the requirements for a specific intended use or application, of a set of products that form a “complete” functional system, have been fulfilled.

**3.1.7**
**system integration test**
**SIT**
Test conducted to validate that the requirements for a specific intended use or application, of a set of products that form an integrated system, have been fulfilled.

**3.1.8**
**validation testing**
Test conducted to confirm that the requirements for a specific intended use or application of a product have been fulfilled.

**3.1.9**
**verification testing**
Test conducted to confirm that the specified requirements for a product have been fulfilled.

## 3.2 Acronyms and Abbreviations

| | |
|---|---|
| BOP | blowout preventer |
| CRA | corrosion-resistant alloy |
| C/WO | completion/workover |
| EFAT | extended factory acceptance test |
| EFL | electrical flying lead |
| FAT | factory acceptance test |
| FMEA | failure modes and effects analysis |
| FMECA | failure mode, effects, and criticality analysis |
| HAZOP | hazard and operability study |
| HFL | hydraulic flying lead |
| HIPPS | high integrity pressure protection system |
| HPHT | high-pressure high-temperature |
| HPU | hydraulic power unit |
| HSE | health, safety, and environment |
| ICT | interchangeability test |
| IWOCS | installation workover control system |
| LRFD | load and resistance factored design |

| | |
|---|---|
| MCS | master control station |
| MODU | mobile offshore drilling unit |
| MPFM | multiphase flow meter |
| NORM | naturally occurring radioactive materials |
| OEM | original equipment manufacturer |
| OREDA | Offshore Reliability Data |
| PDT | predeployment test |
| P&ID | piping and instrumentation diagram |
| PLEM | pipeline end manifold |
| QRA | quantitative risk assessment |
| RAM | reliability, availability, and maintainability |
| ROT | remotely operated tool |
| ROV | remotely operated vehicle |
| SCM | subsea control module |
| SFT | system function test |
| SIT | system integration test |
| SRT | site received test |
| SUDU | subsea umbilical distribution unit |
| SUT | subsea umbilical termination |
| TBD | to be determined |
| TCRT | tree cap running tool |
| TFL | through flowline |
| THRT | tubing hanger running tool |
| TRT | tree running tool |
| USV | underwater safety valve (see API 6A [17]) |
| VIV | vortex induced vibration |
| WSD | working stress design |

# 4 Subsea Production Systems

## 4.1 General

Subsea production systems can range in complexity from a single satellite well with a flowline linked to a fixed platform or an onshore installation, to several wells on a template or clustered around a manifold producing via subsea processing/commingling facilities, and transferring to a fixed or floating facility, or directly to an onshore installation.

Subsea production systems can be used to develop reservoirs, or parts of reservoirs, which require drilling of the wells from more than one location. Deepwater conditions can also inherently dictate development of a field by means of a subsea production system, since traditional surface facilities such as on a steel-piled jacket might be either technically unfeasible or uneconomical due to the water depth.

Subsea equipment may also be used for the injection of water/gas into various formations for disposal and/or to provide pressure maintenance in the reservoir.

## 4.2 System Configuration

The elements of the subsea production or injection system may be configured in numerous ways, as dictated by the specific requirements and the operator strategy. For a description of various subsystems and components that can be combined to form a complete subsea system, refer to API 17TR13. Figure 1 provides an overview of a basic subsea system with references to the relevant API 17-series documents.

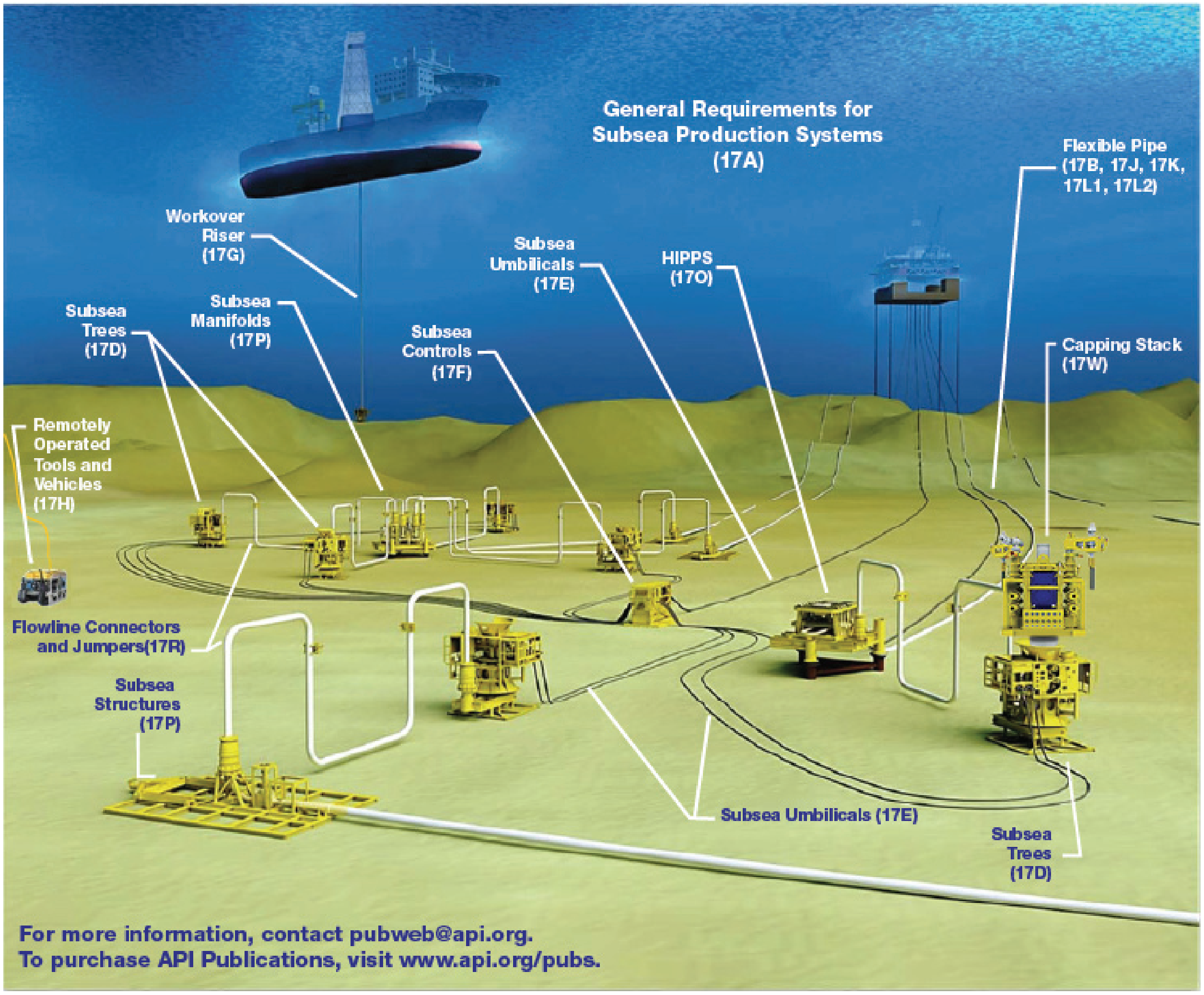


**Figure 1—Basic Subsea Systems**

## 4.3 Overview of API 17-series Documents by Categories

### 4.3.1 System Level Documents

Subsea documents that address system requirements include:

— ***API 17A, Design and Operation of Subsea Production Systems—General Requirements and Recommendations.*** Provides general requirements and recommendations for the development of subsea production systems, from the design phase to decommissioning and abandonment. This document also provides guidance to other API 17-series and related documents.

— ***API 17N, Recommended Practice for Subsea Production System Reliability and Technical Risk Management.*** Reliability is critical to subsea production system design and operation. This recommended practice (RP) provides a comprehensive approach to help assure that reliability needs are achieved with subsea systems. It is broadly referenced in the deepwater technical community as a foundation document for addressing reliability.

— ***API 17O, Recommended Practice for High Integrity Pressure Protection Systems (HIPPS).*** This standard establishes criteria for high integrity pressure protection system (HIPPS) systems that are seeing increased utilization in industry as a means to safely provide overall system pressure capability while restricting the section that requires full shut-in pressure rating to a segment that is close to the source.

— ***API 17Q, Recommended Practice for Subsea Equipment Qualification—Standardized Process for Documentation.*** This RP provides guidance on relevant qualification methods that may be applied to facilitate subsea project execution.

— ***API 17V, Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications.*** This RP provides a comprehensive treatment of the requirements for safety systems necessary for a variety of subsea applications.

— ***API 17TR5, Avoidance of Blockages in Subsea Production Control and Chemical Injection Systems*** [6]***.*** In addition to addressing the avoidance of blockages, this report also includes requirements and gives recommendations for the design and operation of subsea production systems with the aim of preventing blockages in control and production chemical fluid conduits and associated connectors/fittings.

— ***API 17TR6, Attributes of Production Chemicals in Subsea Production Systems*** [7]**.** Production chemicals delivered to a subsea production system via a chemical injection system can be complex formulations that have a wide range of chemical and physical properties. In service, the production chemicals can come into contact with other fluids, metallic and polymeric materials, and a range of physical conditions in respect of temperature and pressure. This report was developed with the objective of minimizing the risk of a production chemical not being delivered at the required volumetric rate, due to inadequate specification of the production chemical delivery system, or formation of restrictions or blockages in that system.

— ***API 17TR13, General Overview of Subsea Production Systems*** [12]**.** This document provides descriptions and basic design guidance on subsea production systems.

#### 4.3.2 Subsea Hardware (Wellheads, Trees, Manifolds, and Structures)

Subsea documents that address assembled equipment include:

— ***API 17D, Specification for Subsea Wellhead and Christmas Tree Equipment*****.** This specification provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads, vertical and horizontal subsea trees, and the associated tooling for handling, testing, and installing this equipment.

— ***API 17P, Recommended Practice for Structures and Manifolds of Subsea Production Systems.*** This RP addresses recommendations for subsea structures and manifolds utilized for pressure control in both subsea production of oil and gas and subsea injection services.

— ***API 1PER15K-1, Protocol for Verification and Validation of HPHT Equipment*** [1]***.*** This report focuses on an evaluation process for high-pressure high-temperature (HPHT) equipment in the petroleum and natural gas industries, which includes design verification analysis, design validation, material selection considerations, and manufacturing process controls necessary to ensure the equipment is fit-for-service in the applicable HPHT environment. The design verification and validation protocols in this report are intended to be used as a guide by the various API subcommittees to develop new and revised standards on equipment specifications for HPHT service.

— ***API 17TR3, An Evaluation of the Risks and Benefits of Penetrations in Subsea Wellheads Below the BOP Stack*** [4]***.*** This report documents the results of a study of the risks and benefits of additional penetrations in subsea wellheads below the blowout preventer (BOP) stack for the purpose of monitoring additional casing annuli for sustained casing pressure. Special attention was paid to the risk and benefits introduced by monitoring annuli other than the “A” annulus (the annulus between the production tubing and the production casing strings).

— ***API 17TR4, Subsea Equipment Pressure Ratings* [5].** The impact of operation in deep water on the pressure rating of equipment is a special concern. The objective of this document is to foster a better understanding of the effects of simultaneous internal and external pressures on the rated working pressure of equipment covered by the scope of API 17D.

— ***API 17TR8, High-Pressure High-Temperature (HPHT) Design Guidelines* [8].** Current API standards for deep water typically cover applications where the shut-in pressure is 15,000 pounds per square inch or less. In recent years, industry has been pursuing deepwater assets that have shut-in pressures above 15,000 psi, and operators and regulatory agencies have had to address these applications on a singular basis. API 17TR8 establishes a standardized industry approach to the analysis, design, material selection, testing, and application of subsea component hardware for these HPHT applications.

— ***API 17TR11, Pressure Effects on Subsea Hardware During Flowline Testing in Deep Water* [10].** This report provides guidance to the industry on allowable pressure loading of subsea hardware components that can occur during hydrotesting of subsea flowlines and risers and during precommissioning leak testing of these systems. There are potential problems with confusion arising from high hydrostatic pressure in deep water, partially due to the variety of applicable test specifications and partly from the inconsistent use of a variety of acronyms for pressure terminology.

— ***API 17TR12, Consideration of External Pressure in the Design and Pressure Rating of Subsea Equipment* [11].** Historically, consideration of the benefit of external pressure in deepwater applications has been accepted in some applications involving the design and pressure rating of pipe. This report provides a detailed review of the full system considerations that must be taken into account if one is to consider external pressure in the design of an irregular-shaped subsea pressure-containing or pressure-controlling device.

### 4.3.3 Flowlines and Risers

Subsea documents that address risers and flowlines include:

— ***API 17B, 17L2, 17J, 17K, and 17L1, Flexible Pipe and Ancillary Equipment.*** These documents provide a comprehensive treatment of the design, manufacture, testing, packaging, and utilization criteria for both bonded and unbonded flexible pipe, as well as the ancillary equipment necessary to control the flexible pipe behavior, protect a transition area, or provide a means of attachment and seal.

— ***API 17R, Recommended Practice for Flowline Connectors and Jumpers.*** This RP provides applicable criteria for all types of remote connections, and associated pipework, made between subsea flowline/pipeline end connections, manifolds, and subsea trees. This RP covers subsea flowline connectors and jumpers utilized for pressure containment in both subsea production of oil and gas and subsea injection services.

— ***API 17U, Recommended Practice for Wet and Dry Thermal Insulation of Subsea Flowlines and Equipment.*** This RP provides guidance for the performance, qualification, application, quality control, handling, and storage requirements of wet and dry thermal insulation for subsea applications in the petroleum and gas industries. This document also covers the inspection of the insulation and the repair of insulation defects.

— ***API 17TR1, Evaluation Standard for Internal Pressure Sheath Polymers for High Temperature Flexible Pipes* [2].** This report defines the methodolgy and test procedures necessary for the evaluation of polymeric materials suitable for use as the internal pressure sheath of unbonded flexible pipes in high-temperature applications. It describes the processes by which the critical material properties, both static and dynamic, can be measured and evaluated against relevent performance criteria.

— ***API 17TR2, The Aging of PA-11 in Flexible Pipes* [3].** This report provides comprehensive guidance on materials and pipe issues regarding the use and operation of PA-11 in flexible pipe applications, typically in production and gas handling applications up to 100 °C. It concentrates on the use of PA-11 in the internal sheath of flexible pipes, although similar considerations may also apply to other uses of PA-11 within flexibles, e.g. anti-wear layers, intermediate sheathes, and outer sheathes.

#### 4.3.4 Control Systems

Subsea documents that address control system requirements include:

— ***API 17E, Specification for Subsea Umbilicals.*** This document specifies requirements for the design, material selection, manufacture, design verification, testing, installation, and operation of subsea umbilicals and their ancillary equipment. It applies to umbilicals for static or dynamic service, with surface-surface, surface-subsea, and subsea-subsea routings.

— ***API 17F, Standard for Subsea Production Control Systems.*** This standard provides criteria for the design, manufacture, testing, and operation of various types of surface control system equipment, subsea control systems, and requirements for the associated control fluids. This equipment is utilized for control of subsea production of oil and gas and for subsea water and gas injection services.

— ***API 17S, Recommended Practice for Design, Testing, and Operation of Subsea Multiphase Flow Meters.*** This RP provides minimum requirements for subsea multiphase flow meters to help assure mechanical and electrical integrity, communications capability, and measurement performance for reliable use.

— ***API 17TR10*, *Subsea Umbilical Termination (SUT) Design Recommendations*** [9]***.*** This report was generated in response to the increasing difficulties in installation of high-functionality subsea umbilical terminations (SUTs), due to their increasing size. While there are universally accepted standards for the design of an SUT and its subsystems, none of these standards specifically address the subject of the risks of installation and the measures required to minimize these risks.

#### 4.3.5 Intervention Systems

Subsea documents that address requirements for intervention systems include:

— ***API 17C, Recommended Practice on TFL (Through Flowline) Systems.*** This RP specifies requirements and gives recommendations for the design, fabrication, and operation of through flowline (TFL) equipment and systems, for the hydraulic servicing of downhole equipment, subsea trees and tubing hangers, and flowlines and equipment within the flowlines.

— ***API 17G, Recommended Practice for Completion/Workover Riser Systems.*** This RP provides criteria for the design, manufacture, testing, and operation of completion/workover (C/WO) riser systems run from a floating vessel. It is applicable to all new C/WO riser systems and may be applied to modifications, operation of existing systems, and reuse at different locations and with different floating vessels.

— ***API 17H, Recommended Practice for Remotely Operated Tools and Interfaces on Subsea Production Systems.*** This RP provides recommendations for the development and design of remotely operated subsea tools and interfaces on subsea production systems in order to maximize the potential of standardizing equipment and design principles. Criteria for standardized interfaces found in this document are utilized in nearly all other subsea operations (e.g. drilling, construction, etc.) that require remotely operated vehicle (ROV) support or interaction.

— ***API 17W, Recommended Practice for Subsea Capping Stacks.*** This document captures the best practices in the design and operation of existing capping stacks and provides a foundation for consistent practices in the design, manufacture, testing, and utilization of future stacks. It is intended to be applied to the construction of new subsea capping stacks components but can be also used to improve existing subsea capping stacks.

— ***API 17TR15, Hot Stab Hydraulic Interface*** **[13]*.*** This report describes a number of common or previously used ROV hydraulic hot-stab and receptacle configurations. The intent is to ensure backward compatibility of the hot stab described in API 17H, Second Edition, June 2013, and to align API 17H with API S53 and API 16D. API 17TR15 defines three major categories of hot stabs and describes the geometry to maintain compatibility across all manufacturers.

# 5 Systems Engineering

## 5.1 General

Systems engineering is a multidisciplinary approach that covers the complete system, from the reservoir to the host, with consideration of the requirements of all of the various phases of the development, including contracting, engineering, procurement, construction, inspection, testing, load-out, installation, systems completions, operation, workover/maintenance, modification, and abandonment. Simply put, it is a systematic engineering approach covering the entire life cycle of the system.

The systems engineering process consists of the technical management of all technical aspects. An evaluation of the need for application of the various systems engineering processes should be performed for each specific field development, based upon the characteristics of the development. To be effective, the systems engineering process will maintain focus on the information that will be required to transfer the system from one phase to another. An overview of the system conditions should be considered as part of the life cycle systems engineering to allow service life extension.

## 5.2 Process

The systems engineering process should be systematically maintained throughout the entire life cycle of the system, as requirements typically tend to evolve through the development life cycle. This maintenance should be ensured by:

— a controlled requirements database that is visible to all and is the only repository of information,

— system design reviews at critical milestones,

— requirement traceability and verification, and

— lifelong change control.

Guidance on the systems engineering process can be found in the following documents:

— INCOSE *Systems Engineering Handbook* [51],

— ISO/IEC/IEEE 15288 [59],

— MITRE Corporation, *Systems Engineering Guide* [67],

— Systems Engineering Body of Knowledge [79].

## 5.3 Systems Engineering Inputs

### 5.3.1 General

The systems engineering process is based on various inputs. These inputs typically include:

— regulatory standards;

— company standards;

— safety considerations;

— project needs and/or goals, such as:

  — profitability,

  — environmental compliance,

  — technology development needs;

— partner or in-country content requirements.

Datasheets suitable for capturing the system engineering inputs are provided in API 17D.

### 5.3.2 Operational Considerations

The design of a subsea production system should take into account all phases of the field life, the requirements to operate the field, and the design data and design loads relevant at the location of the subsea installation. Provision for possible future extensions and operational flexibility to cater for reservoir uncertainty should be considered at an early design stage. The subsea production system may be designed to accommodate any future equipment, including subsea processing. Consideration should also be given to brownfield infrastructure that may influence design (e.g. conduct early brownfield as-built surveys, particularly for surface controls equipment).

Expected duty cycles, frequencies, and the limits of operational, maintenance, or other kinds of system demand, including prohibitions of system configurations, should also be considered.

### 5.3.3 Environmental Data

The following data are typically required for the installation site of the subsea installation, as well as flowline routes in the field and along pipeline routes for export:

— *water*—depth, visibility, salinity, temperature, lowest astronomical tide level, highest astronomical tide level, resistivity, oxygen content, pH, mass density, specific heat capacity, swell, and surge;

— *waves*—height, wavelength, frequency, distribution, and periodic occurrence;

— *currents*—velocity profile, direction, distribution, and periodic occurrence through the water column;

— *weather*—air temperature, wind speeds, wind direction, distribution, and periodic occurrence;

— *icebergs*—size, mass, frequency of occurrence, direction, velocity;

— *seabed*—soil description, friction angles, soil shear-strength, depth profile and load-bearing capacity, pockmarks, presence of shallow gas, earthquake data, seabed topography, stability under cyclonic conditions, resistivity, density, marine growth, subsea obstacles, volcanoes, mudslides, scouring, topology, subsurface hydrates, thermal conductivity, friction factors, and lithology.

### 5.3.4 Reservoir and Fluid Data

The following data are typically required for various points over the field life:

— reservoir characteristics (e.g. basic sediment and water data including reservoir depth, type, life, and inflow information);

— product characteristics [e.g. shut-in pressure, flowing (max./min.) pressure, temperature, density, gas-oil ratio, water cut, bubble point, chemical composition, corrosivity ($H_2S$ and $CO_2$ mol %), sand, emulsions, wax content and wax appearance temperature, asphaltenes and hydrates, flowrates, API Gravity, chlorides/salinity/pH of produced water, viscosity, cloud points, pour point and scaling potential, formation-water content of minerals];

— injection characteristics (e.g. turbidity, oil in water or gas allowances, scaling probability, pressure, temperature, corrosivity, filtration requirements).

### 5.3.5 Safety Strategy

Management of technical safety in project development and design processes comprises activities to identify and mitigate risks and develop safety strategies and performance requirements for safety systems and barriers.

A safety strategy should be established during design for the purpose of:

— managing technical safety;

— maintaining or improving the level of safety of the system;

— reducing the probability that hazards will arise;

— reducing the probability of a hazard escalating into an undesirable event or condition;

— halting or limiting the escalation process or reduce the scope and duration of undesirable events; and

— limiting the impact of accidents.

The strategy and performance standards for safety systems should be in accordance with API 17V and recognized principles of health, safety, and environment (HSE) management systems. Additional guidance may be found in IEC 61508 [47] and IEC 61511-1 [48] and should:

— be the outcome of a systematic identification and evaluation of the hazards and effects that may arise during design, fabrication, transportation, load-out, installation, systems completion, operation, and abandonment and will define the need for, and role of, the risk reducing measures and safety systems;

— outline the design principles for layout, arrangement, and selection of which safety barriers and systems to go into the design, ensuring a consistent and robust design that will be the basis for a safe operation of the system;

— address operational aspects, which then should serve as an input to the development of the operational procedures.

— involve monitoring of performance in service and during testing and maintenance. The performance should be reassessed against original requirements on a regular basis.

### 5.3.6 Barrier Considerations

As part of the overall subsea production system design, a comprehensive barrier philosophy should be developed. The barrier philosophy should provide clear and concise guidance on barrier requirements, with the objective of preventing unintentional release of produced/injected fluids that may harm personnel and/or the environment.

For new subsea projects, a complete barrier philosophy should be developed prior to the commencement of detailed design. This document should define what types and how many barriers are required for operation of the facilities, through all of the various phases of the field life, including the following:

— installation activities, including tie-in of subsequent wells to a live manifold;

— drilling and completion activities, including well testing and clean-up activities;

— hook-up and commissioning activities;

— routine production operations, for both producing/injecting and shut-in modes as well as for service modes such as circulating of flowlines and pigging;

— well intervention activities, involving reentry into a well and or retrieval of a tree;

— maintenance activities, such as replacement of a subsea choke;

— decommissioning activities.

Similarly, for new subsea projects the barrier philosophy should cover all of the pressure-containing elements of the system, from the reservoir(s) through to the first block valve(s) at the receiving/injecting facilities on the permanent host facility or the mobile offshore drilling unit (MODU)/intervention vessel, as applicable.

In situations where a project/field specific barrier philosophy (as described above) does not exist (e.g. for preexisting subsea production facilities), then it is advisable to develop an operating barrier philosophy or generic barrier philosophy to cover at the least the barrier requirements during "routine" operation of the system, i.e. production, shut-ins and barrier testing. A case-specific barrier philosophy can then be developed prior to any intervention, workover, etc., activity to address those elements not covered in the operating/generic barrier philosophy document.

Given the wide variety of possible field characteristics and equipment configurations, as well as the varying requirements of existing local regulations combined with field operator preferences, it is not possible or desirable to provide specific guidance that could be used as a standard barrier philosophy. Notwithstanding this constraint, it can be stated that

— the barrier philosophy for each subsea production system shall be consistent with all applicable local regulations;

— a barrier shall be testable;

— while some aspects of a generic barrier philosophy may be applicable to many subsea production systems, each specific situation should be evaluated on a case-by-case basis to at least confirm that the generic barrier philosophy is appropriate and applicable;

— development of both generic and case-specific barrier philosophies requires the use of experienced personnel and typically involves the use of one or more risk assessment techniques such as hazard and operability study (HAZOP), failure modes and effects analysis (FMEA), quantitative risk assessment (QRA), task analysis, and/or scenario-based risk assessment;

— the barrier philosophy should be clearly communicated to all relevant personnel, including design engineers, equipment suppliers, and field personnel;

— the guidance/requirements contained in the barrier philosophy should be clear and concise, i.e. not open to different interpretations and/or misinterpretation.

The following documents provide relevant information regarding barrier considerations for subsea equipment:

— API 96 [24];

— IMCA D044 [50];

— NORSOK D-010 [70];

— Oil & Gas UK, *Well Life Cycle Integrity Guidelines* [75];

— OLF 117 [76].

## 5.4 Systems Engineering Approach

### 5.4.1 General

The first step in applying a systems engineering approach is to define a complete, unambiguous, and seamless set of requirements consistent with the stated objectives for the development. Broadly speaking, the objectives for any given development fall into one of the following three categories:

— quality (including HSE objectives throughout the full life cycle of the development/field, as well as functionality, operability, and availability requirements);

— cost (including cost of operation, intervention, and decommissioning/abandonment, i.e. life cycle cost);

— schedule (including time to first production and field life).

The systems engineering requirements should be developed using input based on the experience and understanding of all of the key internal and external stakeholders, i.e. a team that includes not only project personnel but also early engagement of representatives from relevant interfacing disciplines (e.g. topsides, operations, drilling, subsurface, marine, installation, and/or geotechnical) as well as contractor and equipment suppliers.

### 5.4.2 Safety by Design

The outcome of a systematic identification and evaluation of the hazards and effects that may arise will define the need for risk-reducing measures and performance standards for the safety systems. General guidance on tools and techniques for hazard identification and risk assessment, control, and mitigation can be found in ISO 17776 [60].

Emphasis should be placed on inherently safer designs to eliminate or reduce hazards at the source. Applying inherently safer design principals early in project development provides the greatest opportunity for risk reduction and should be part of the system engineering process.

### 5.4.3 System Functional and Design Requirements

System engineering requirements should define the functional requirements of the system and the interfaces between the various subsystems, as opposed to stating a directed physical solution. They should be attainable as well as verifiable and should be stated in a clear and concise manner that includes definition of the verification method to be applied (e.g. examination, test, analysis, and/or demonstration).

A complete set of systems engineering requirements comprises a consistent set that does not have contradictory or duplicated individual requirements and that uses the same term for the same item in all requirements.

Referenced documentation such as regulations, standards, and codes often have a range of mandatory requirements, guidance, and information in them (i.e. information being nonbinding statements that nonetheless can significantly influence the context, meaning, and understanding of the other requirements). Therefore, the desired level of compliance should be clearly established at the outset in the systems engineering requirements (i.e. what is mandatory, what is guidance, and what is information). It is recommended that a hierarchical order and applicability limits be defined for the application of such documents, so as to minimize the impact of any inconsistencies that exist and to understand and control scope creep.

When a complete set of systems engineering requirements is impossible to establish at the outset due to a lack of key information, then a plan for obtaining the lacking information should be formed, so as to ensure that the information is available prior to the start of system, subsystem, and component design. Systems engineering often makes frequent use of "TBD" or "HOLD"; this denotes that information is required but may not yet be established. Not only does the TBD point out missing data, but the grouping of TBDs can provide valuable metrics on the progress of the design itself.

Systems engineering requirements should provide guidance on the following aspects of the system:

— the required operational life from commissioning to decommissioning;

— the degree of equipment standardization required;

— the materials selection philosophy;

— the degree of flexibility required to allow for reservoir uncertainty and/or future expansion of the system;

— the application of new technology and risk management;

— the basis to be used for cost, schedule, and quality trade-offs;

— the responsibility for each external and internal interface;

— the application of definitions, specifications (including guidance on specification breaks), standards, rules and regulations to be used in the design;

— the system-level testing [i.e. system function test (SFT), system integration test (SIT), and system hydrotest] and systems completions philosophies;

— the operating strategy;

— the maintenance/reliability goals, including the desired system uptime/availability;

— the intervention, maintenance, repair, sparing, preservation, and storage philosophies.

#### 5.4.4 System Interface Management

Interfaces are developed in the same manner as are all requirements; they are developed as requirement statements supplemented by drawings and documentation. Each requirement statement is verifiable and can be documented as being met during the project.

The objective of interface management is to achieve functional and physical compatibility among all of the various interrelated system elements that must interface with each other, in terms of fit, form, and/or function. Clear identification, definition, and management of system internal and external interfaces and/or constraints during the life cycle of the system are necessary to ensure smooth transfer of equipment care, custody, and control and to maintain a safe operation (e.g. allowable loads and responsibilities during load-out, installation, drilling, and intervention activities, etc.).

Implementation of an effective interface management process facilitates controlling a subsea system design, particularly when efforts are divided among parties (e.g. customer, contractors, geographically diverse technical teams, etc.). It is essential to establish the interface management process early and align on key interfaces among parties. Direct involvement of technical personnel from each party in the interface helps to avoid erosion of technical detail and schedule. It is important for both parties to clearly understand the need, deliverable format, timing, and eventual use of data to efficiently progress the subsea system design. Communication, cooperation, compromise, consistency, and commitment are the keys to successful interface management.

### 5.4.5 System Design Basis

The above information should be used to develop an internally consistent design basis, covering the various subsystems and components that are understandable by all involved parties, prior to the start of engineering of such subsystems and components.

The design basis should cover the following fundamental system characteristics for each subsystem or component:

— applicable standards;

— functional requirements;

— system architecture;

— process, operating, and environmental parameters;

— interface definitions (form, fit, function, etc.);

— design and operational constraints.

## 5.5 Systems Engineering Analyses and Evaluations

### 5.5.1 Systems Engineering Analyses

The systems engineering process will likely highlight conflicting requirements or requirements that can be met in a variety of ways. Additionally, the flow-down nature of requirement development can highlight gaps, which may also lead to system analyses.

The following system-level analyses and evaluations are typically performed during design, based on project specific requirements and applicable API 17-series standards and technical reports for subsea hardware, flowlines/risers, control systems, and intervention systems:

— flow assurance analysis (refer to 5.5.2);

— structural analysis, including fatigue and lifting (refer to 6.5);

— piping analysis, including rigid pipe, flexible pipe, erosion, and fatigue (refer to 6.6);

— insulation mechanical stress analysis;

— overpressure protection (refer to API 17O);

— dimension and tolerance evaluation (refer to API 17D for guidance);

— hydraulic system analysis (refer to API 17F for guidance);

— chemical injection system analysis (refer to API 17F as well as API 17TR5 [6] and API 17TR6 [7] for guidance);

— electrical power and communications system analysis (refer to API 17F for guidance);

— cathodic protection analysis (refer to DNV-RP-B401 [33] for guidance);

— ROV accessibility analysis (refer to API 17H for guidance);

— installation planning and constructability analysis (refer to 6.13)

— lifting and installation analyses (refer to 8.5);

— dropped object risk and impact analysis (refer to 6.7);

— snagging and trawlability analysis (refer to 6.7);

— reliability analyses [reliability, availability, and maintainability (RAM) and failure mode, effects, and criticality analysis (FMECA)] (refer to 5.5.4);

— obsolescence management evaluation (refer to 7.2);

— material selection and corrosion protection (refer to 6.4);

— subsea pressure testing limitations (refer to 5.5.3)

#### 5.5.2 Flow Assurance Analysis

Systems engineering in subsea field developments plays a central role in the area of flow assurance, as the ability to successfully optimize the flow of fluids from the field requires the application of a holistic (i.e. systems-level) approach through all of the aspects of the development.

Flow assurance is a term commonly used to cover a wide range of flow-related issues, which typically include:

— hydrate formation;

— wax formation;

— asphaltene precipitation;

— emulsions;

— foaming;

— scale formation;

— sand production;

— slugging;

— materials related issues (corrosion, extreme temperatures).

As these issues are directly related to the specific reservoir and/or fluid properties of the field being developed, a careful evaluation of the potential impact of each of these issues is required for each new development. This is particularly true for subsea production systems with long offsets from the host facility and/or that are located in deep water, as the challenges presented by many of the above-mentioned issues are exacerbated by the produced fluids being cooled down by the surrounding cold seawater environment while transiting the flowlines and risers connecting the subsea trees/manifold to the host facility.

It is conceivable the widespread application of subsea processing in the future could negate or reduce the impact of some of the above-mentioned issues for many developments, but until that time these issues dominate the feasibility of an increasing number of subsea developments.

In general and at a minimum, a first-pass evaluation should be conducted for each new subsea development to determine the potential impact of each of the above-mentioned issues on the performance of the production system. This first-pass evaluation should be conducted as early as practically possible in the planning phase of the development to identify any key vulnerability. The evaluation should cover the entire system over its life cycle, from the perforations through to and including the processing/storage/export facilities on the host facility [including the potential impact of flow assurance solutions (such as chemicals) on the exported fluids] at various phases of the development. Additionally, for subsea tie-backs, the first-pass evaluation should include any "brownfield" assets that the new subsea development is tying into so the performance of the holistic system is considered.

Various factors can have a significant influence on the flow assurance issues for a development, including:

— the hydrostatic head in the product lines/completion riser, under flowing and shut-in conditions;

— the insulating characteristics of the seabed soils;

— the seabed temperature profile;

— the seawater temperature and ambient air temperature profiles for risers and topside piping;

— the seabed terrain profile;

— planned and unplanned flowrate changes in individual lines (e.g. due to natural well flowrate decline, redirection of a single well into a test line for metering purposes, shut-in of a well due to a mechanical failure, etc.);

— changes in the reservoir and/or produced fluid properties over the life of the facility (e.g. reservoir pressure decline, commencement of sand production, increasing water cut, changes in gas-oil ratio, changes in oil API Gravity, etc.);

— the chemical compatibility of any chemicals introduced into the product streams, with the produced fluid, other chemicals being used, the materials of construction, and with the export route for produced fluids;

— subsea system configuration (including system insulation characteristics).

For those flow assurance issues identified as having the potential to significantly impact the performance of the system over its life cycle, further evaluation should be undertaken to predict the extent and severity of the problem and to identify possible prevention and remediation measures. Such evaluation is best handled by a multidisciplinary team that can apply expert knowledge over the system life cycle.

Two key elements in correctly assessing the impact of flow assurance issues on any given production system are as follows.

— An accurate understanding of the properties of the fluids being produced. This is typically based on a series of empirical observations and measurements using fluid samples collected during the exploration phase of the project.

— The ability to accurately model the fluid flow from the sand face to the host facility, including prediction of the prevalent flow regimes as well as the detailed pressure and temperature profiles under both transient and steady-state conditions.

The fluid-flow modelling is typically performed after the exploration wells are drilled and can be further improved upon as new information becomes available; however, deficiencies in the exploration-well fluid sampling program cannot be easily rectified once the rig has been demobilized from the site. Hence, attention should be given to defining the requirements of the fluid sampling program and gathering adequate data for the optimization of future production facilities, prior to commencement of the drilling of exploration and/or appraisal wells.

Determination of the fluid properties, combined with modelling of the fluid flow through the system, should provide sufficient data for an overall assessment of the above-mentioned issues. Once this assessment is available, an operating strategy addressing the following elements should be developed and updated regularly:

— the prevention techniques to be employed for prevention/minimization of solids deposition, etc.;

— the remediation techniques to be employed to recover from situations where solids deposition, etc. does occur;

— how slugging will be managed (if an issue);

— the methodology to be used for ramp-up and turndown of production rates;

— the methodology to be used for shutdowns (planned and unplanned) and start-ups (from cold, warm, pressurized, and depressurized conditions);

— the monitoring processes to be employed to ensure the system is behaving as designed;

— how the subsea and subsurface safety valves will be tested;

— how routine well tests will be conducted.

OTC 14010 [77] and the joint industry technical development project DEEPSTAR® may be referenced for further guidance and information on flow assurance issues.

#### 5.5.3 Evaluation of Subsea Pressure Testing Limitations

The subsea system is comprised of several subassemblies/components designed per various industry standards. The maximum design pressure of each subsea hardware subassembly/component in the system to be pressure tested subsea should be evaluated in order to identify the weakest link, such that the subsea system pressure test requirements can be defined accordingly. The evaluation should consider the performance and integrity of each subassembly/component within the system, barrier philosophy, and environmental considerations, as well as the subsea system testing philosophy, which typically includes one or more of the following test activities:

— back seal test(s) (initial verification of connection integrity between subassemblies),

— barrier test(s) [often brownfield specific to prove a subassembly/component (e.g. a valve) is leak-tight in advance of an internal leak test],

— internal leak test(s) (final verification of connection integrity between subassemblies),

— subsea hydrotest(s) (verification of flowline/pipeline integrity or any other subsea equipment subassembly, which has not already been verified via an onshore hydrotest).

Refer to API 17TR4 [5], API 17TR11 [10], API 17TR12 [11], API 1110 [25], and API 1111 [26] for additional guidance.

#### 5.5.4 Subsea Production Assurance and Reliability Management Analyses

Production assurance and reliability management is important for safe and efficient operation of subsea production systems. Redundancy of equipment, components, and/or functions should be analyzed as a system and considered with respect to safety, cost, reliability, and availability. This requires appropriate use of API 17N in the different life cycle phases. Application of ISO 14224 [58] is relevant to ensure that correct reliability data are being used in the reliability work processes. The best available subsea reliability data should be used in these reliability activities and analyses from standard sources [e.g. in-house reliability data, Offshore Reliability Data (OREDA), etc.]. In-house reliability data should be documented and justified by in-service records, calculations, and/or empirical tests and relate to the service and environmental conditions.

FMECA analysis typically provides input to RAM analysis to eliminate, or mitigate the effects of, critical failure modes. RAM analysis typically determines the expected system uptime/availability, probability of success for achieving the reliability performance targets, sparing consumption and redundancy over field life to maintain project availability requirements commensurate with maintenance/reliability goals, and components for reliability improvement, specifically identifying critical components whose failure rates have the greatest influence on the overall failure of the system and/or subsystem that may be improved upon.

Consideration should be given to comparing spare parts lists against existing spare parts inventories managed by operations, particularly for brownfield projects, to avoid ordering unnecessary spares. A recommended spare parts list and ROV/ROT tooling is typically needed at the start of design to allow time for operations to run interchangeability reports to determine spare order quantity and as input to operations and maintenance activity/procedure development.

Obsolescence of equipment is inevitable and may result in a loss of system availability. Guidance on obsolescence management in subsea systems is provided in 7.2.

## 5.6 Systems Engineering Documentation

A major feature of using a systems engineering approach to design and development is the feature that all requirements are held in a central location and are visible to all. In most cases, the central location is a database of some type; there are a number of systems engineering databases purpose-built for requirements management and use of one of these is highly recommended.

The systems requirements document has a key role to play in subsea field development. It is the basic source for consistent communication of requirements to all of the stakeholders involved and for development of project and operations documentation (e.g. the verification plan, recommended spare parts lists, etc.). It is also a validation device for the stated requirements, as well as the basis for user manuals, operations and maintenance procedures, and other documents that will be developed describing how the complete system fits and works together.

## 5.7 System Reviews

### 5.7.1 Engineering Reviews

Systems engineering reviews typically cover the following design and operability aspects:

— design basis, verification, and qualification programs;

— technical compliance and deviations;

— field layouts and piping and instrumentation diagrams (P&IDs);

— testing plans and test equipment;

— tagging;

— flow assurance and hydrate prevention;

— intervention and ROV access;

— system-level testing and test equipment;

— system engineering analyses;

— reliability analysis results compared to maintenance/reliability goals;

— HAZOP and risk assessment planning;

— load-out planning;

— precommissioning and commissioning procedures;

— systems completions;

— systems engineering documentation and documentation for operations;

— recommended spare parts lists and spares management;

— training.

Guidance on the design review process can be found in IEC 61160 [46].

### 5.7.2 Operability Reviews

Operability reviews typically address:

— operability and reliability performance targets;

— reliability analyses;

— systems completion, precommissioning and commissioning procedures;

— spare parts;

— equipment tagging;

— operator training;

— documentation for operations.

# 6 Equipment Design Requirements

## 6.1 General

The system engineering information should be used to develop a detailed design basis for equipment that is understandable by all involved parties, prior to the start of engineering. In addition the following should apply.

## 6.2 Safety

The design should consider safety during the manufacture, assembly, testing, transportation, and installation by implementing requirements such as the following.

— Permanent access ladders, footholds, platforms, fall protection tie-off points, and/or built-in mounts for removable temporary handrail stanchions should be integrated in equipment design where practical and where manned intervention is required. These permanent safety devices should be designed to not be snagging points subsea.

— Temporary and removable ladders, platforms, scaffolds, mounts, and/or handrail stanchions should be provided to complement permanent safety devices where manned intervention is required during manufacturing, load-out, and transportation. These temporary safety devices should not damage subsea structure paint integrity upon removal.

— Permanent lifting and/or tie down points to facilitate handling and temporary securement of heavy equipment loads during transportation should be integrated in equipment design where practical. These permanent safety devices should be designed to not be snagging points subsea.

## 6.3 Environmental Conditions

All equipment should be capable of withstanding, without significant damage or degradation, the environmental conditions in all intended locations to which the equipment will be exposed during fabrication, testing, transportation, storage, installation, and operation.

## 6.4 Materials and Corrosion Protection

The project design criteria should be considered in materials selection including design lifetime, inspection and maintenance philosophy, safety and environmental profiles, operational reliability, and specific project requirements. Material selection guidance should be established including for fasteners. The materials, welding and corrosion protection selection process shall take into account all statutory and regulatory requirements.

General guidance pertaining to materials selection and corrosion control for equipment used in the oil and gas industry can be found in ISO 21457 [64] and NACE SP0176 [69]. EEMUA 194 [45] contains specific guidance for materials selection and corrosion control for subsea equipment.

API 6A [17] and several of the API 17 series of documents also contain relevant guidance and requirements, for example API 17D, API 17E, API 17G, API 17P, and API 17R.

Guidance on materials for use in $H_2S$-containing environments may be found in NACE MR0175/ISO 15156 [68], while guidance on the use of duplex stainless steels exposed to cathodic protection is contained in DNV-RP-F112 [32].

General guidance on forgings is contained in API 20B [22] and API 20C [23]. DNVGL-RP-0034 [41] contains specific guidance on carbon and low alloy steel forgings for use in subsea applications.

Relevant guidance on protective coatings for subsea equipment is contained in ISO 8501-1 [52], ISO 8503 [53], ISO 9588 [55], and ISO 12944 [56].

## 6.5 Structural Analysis

### 6.5.1 General

Structural analysis of subsea equipment should be completed per the guidance provided in API 17P. The structural analysis should verify that all components, as well as the foundation, will retain structural integrity during lifting, drilling, installation, operation, workover, and abandonment operations.

ISO 19901-2 [61], ISO 19901-4 [62], and ISO 19901-5 [63] contain discussions of methods available for soil-structure analysis.

Additional guidance regarding structural design of subsea templates can be found in NORSOK U-001 [71].

DNV-RP-F301 [33] provides general requirements for the structural design, manufacture, testing, and certification processes for subsea gravity separators intended for use in water depths where the governing load is the external, rather than the internal, pressure.

### 6.5.2 Wellhead, Tree, and C/WO Riser System Analysis

Loads on a subsea wellhead system may include component dead loads (mass, weight, gravity), riser loads, flowline pull-in and expansion loads, thermal growth, and direct environmental action. Depending on the tree system, these loads may also be applied to the subsea tree.

Riser loads are transferred to the wellhead/tree system during drilling, well completion, and workover. Depending on the type of subsea system, these loads can be either temporary (i.e. marine drilling riser and

C/WO riser) or permanent (i.e. production risers or injection risers). These loads should be determined by performing riser analysis. Fatigue analysis may also be required where variable loading conditions exist [i.e. due to vessel motions and/or wave/vortex induced vibration (VIV)-induced riser loads].

Applicable loads and applicable load combinations and operational criteria for the determination of riser loads, identification of accidental riser loads, identification of any code-break inconsistencies, and their implications should be established during system engineering.

Note that riser design codes account for normal, extreme, and accidental loading conditions. The design codes used for subsea trees and wellhead systems are normally based on rated capacity for normal operating conditions and on the working stress format. Riser codes are based on either working stress design (WSD) format or load and resistance factored design (LRFD) format.

Further guidance can be found in API 17G, API 2RD [16], API 16Q [21], DNV-OS-F201 [30], DNVGL-RP-0142 [42], and NORSOK U-001 [71].

Flowline pull-in loads can induce significant shear and bending moments on the wellhead. Consideration should also be given to the effects of thermal growth or contraction in the well tubulars and attached flowlines and to additional loads due to the possible nonverticality of the wellhead.

For template wells, the interface between the well and the template manifold piping is particularly critical and should be analyzed for tolerances related to variation in temperature, pressure, position, and elements of orientation of both well and manifold components. All permutations in parameter values should be considered, including thermal growth of the well and the well's different global index with respect to the manifold piping, and any expected subsidence of the template supporting structure. This interface is a typical critical design feature of a template design and should be carefully analyzed.

A subsea completion may be subject to direct environmental loads, for example current, wave action, earthquakes, ice, and soil movements. Dropped objects and snag loads from anchors or trawls can also be a concern for certain applications.

## 6.6 Piping Analysis

External loads, reactions, and fluid characteristics from reservoir and environmental data are used as input to piping analysis of the subsea equipment, including erosion per API 14E [19] and fatigue. Flow path piping analysis typically includes the insulation system and excludes corrosion/erosion allowances [including corrosion-resistant alloy (CRA)-clad material] in any design strength calculation.

Further guidance on specific piping components can be found in API 17B, API 17D, API 17G, API 17J, API 17P, API 17R, and API 17W.

## 6.7 Dropped Objects and Fishing Gear Loads

Each project should perform a field-specific examination in the early phase in order to establish the requirement for dropped object and fishing gear loads (snag loads) protection. Both historical data and expectations for the future should be assessed. Relevant loads and load combinations for the actual application should be defined in the project-specific design basis. The impact force from actual objects that will be handled over the structure should be used as initial design loads.

Unless specified otherwise, the dropped object loads in Table 1 should be used:

**Table 1—Dropped Object Loads**

| Group | Impact Energy | Impact Area | Object Diameter |
|---|---|---|---|
| Multi-well structures | 50 kJ (36,878 ft-lb) | Point load | 700 mm (27.559 in.) |
| | 5 kJ (3,688 ft-lb) | Point load | 100 mm (3.970 in.) |
| Other structures | 20 kJ (24,751 ft-lb) | Point load | 500 mm (19.685 in.) |
| | 5 kJ (3,688 ft-lb) | Point load | 100 mm (3.970 in.) |

Fishing gear loading (snagging) should be considered as an abnormal operation (plastic limit state condition), while impact and frictional loads caused by passing fishing gear should be regarded as normal operation (ultimate limit state) unless the frequency of trawling allows it to be considered a plastic limit state condition. Unless specified otherwise, the fishing gear loads from fishing gear in Table 2 should be used.

**Table 2—Fishing Gear Loads**

| Design Load Type | Design Load Figure | | Limit State |
|---|---|---|---|
| Trawl net friction | 2 × 200 kN (44,961 lbf) | 0° to 20° horizontal | Ultimate limit state |
| Trawl board over pull | 300 kN (67,442 lbf) | 0° to 20° horizontal | Ultimate limit state |
| Trawl board impact | 13 kJ (2,922 lbf) | | Ultimate limit state |
| Trawl board snag | 600 kN (134,885 lbf) | 0° to 20° horizontal | Plastic limit state<br>(if not over trawlable/snag-free) |
| Trawl ground-rope snag | 1000 kN (224,809 lbf) | 0° to 20° horizontal | Plastic limit state<br>(if not over trawlable/snag-free) |
| Trawl board snag on flowline | 600 kN (134,885 lbf) | | Plastic limit state<br>(if not over trawlable/snag-free) |
| NOTE Slightly different fishing gear loads may be specified in regionally applicable codes, such as NORSOK U-001 [71]. NORSOK U-001 also provides for consideration model testing to reduce the loads by designing for overtrawable/snag free structures. | | | |

Further guidance on designing for dropped object loads and fishing gear loads can be found in API 17P.

## 6.8 Lifting Devices, Padeyes, and Unpressurized Structural Components

Due to the broad range of equipment and service requirements, there is not one overall standard to address all lifting devices, padeyes, or unpressurized structural component requirements. Relevant industry guidance is contained in API 2A-WSD [15], API 6A [17], API 17D, ISO 13535 [57], DNV 2.7-3 [28], and DNV-OS-H205 [32]. Guidance on the design and testing of padeyes for subsea wellhead and tree equipment is contained in API 17D.

## 6.9 Colors and Marking

Colors and marking of subsea equipment should satisfy the requirements stated in API 17H.

## 6.10 Tolerance Evaluation

Tolerance evaluation should determine maximum allowable tolerances between mating components and subassemblies (e.g. stack-up, alignment, and engagement) and demonstrate that repeatable interfaces are attainable. Ultimately, this may involve some degree of interchangeability testing as described in Annex A herein.

## 6.11 General Requirements for Transportation, Preservation, and Storage

Plans for the transport, preservation, and storage of equipment should address the following issues:

— transportation,

— handling,

— security,

— preservation,

— Inspection,

— testing,

— maintenance,

— repair,

— refurbishment.

General transportation requirements (such as tie-down analysis for all delivery modes, protective covers, packaging and handling, etc.) should be addressed and documented. DNVGL-ST-N001 [40] provides guidance on sea transport operations.

Equipment handling plans should address certification of lifting equipment and should take into account that different lifting equipment may be required offshore vs onshore, due to increased dynamic loading factors.

Equipment preservation should take into account the need for protection from environmental conditions:

— equipment should be stored under cover if possible;

— elastomeric/thermoplastic components (and assemblies containing such components, e.g. valve actuators) should not be exposed to direct sunlight for prolonged periods;

— electronic components should be stored in an environmentally (i.e. temperature, humidity, and debris) controlled area;

— hydraulic fluid cleanliness should be maintained;

— appropriate preservation fluids should be used to protect equipment surfaces from long-term degradation.

— inspection and testing may include, but not be limited to, visual inspections, flow tests, function tests, pressure tests, electrical checks, dimensional checks, fluid cleanliness checks, and/or pressure tests.

Routine equipment maintenance may include refreshing equipment preservation and/or hydraulic fluids.

Prior to load-out, equipment that has been stored for an extended period and/or under less than ideal conditions may require some level of repair or refurbishment.

## 6.12 Load-out Planning

Early load-out planning is critical to ensure interfaces are properly managed between all parties and mitigations are put in place to address hazards identified during risk assessments performed ahead of load-out. Load-out planning should address, but not be limited to, the following:

— safety, personnel communication, and access,

— sensitive equipment protection during load-out [e.g. flying leads, subsea control modules (SCMs), MPFMs],

— installation aids/sea fastening,

— lifting procedures/crane specifications,

— drawings (e.g. vessel layouts, transportation routes, and vessel/crane elevations),

— quay schedule, load-out sequences/checklists, and constraints relative to transportation vessel, quay, and site,

— mobilization of temporary equipment (e.g. cranes, transports),

— temporary personnel (e.g. marine warranty surveyors),

— marine requirements (e.g. ballasting, bumpers/fenders, moorings, gangways, and additional barges to position vessel),

— potential physical hazards (e.g. sharp edges on support equipment that could damage umbilical, stray electrical currents from welding that could damage electrical equipment).

## 6.13 Installation Planning

Equipment design should not unnecessarily restrict the installation sequence of the subsea equipment, flowlines, pipelines, risers, and umbilicals. Installed equipment size, shape, configuration, and weight may be limited by handling and installation considerations, both onshore and offshore.

The design of the subsea production system should address the following installation related issues, by ensuring that the relevant components:

— do not rely on hydraulic pressure to retain the necessary locking force in connectors;

— allow for cessation of installation operations without compromising safety;

— minimize entry of water or contamination into hydraulic circuits during connections (which can jeopardize system functionality);

— are tolerant of small amounts of seabed debris between the interface connections or allow flushing prior to the makeup action;

— are tolerant of hydrodynamic loads including wave-induced, current and hoisting loads;

— avoid loss of harmful fluids into the environment during installation operations.

Constructability analyses should also be completed, in order to ensure that the proposed facilities are constructable in a safe and efficient manner. Such analysis should consider issues such as types of construction equipment required vs that available, pipeline lay direction and potential interference with other seabed equipment, trade-off studies of structure types [e.g. pipeline end manifolds (PLEMs), manifolds, in-line structures], and installation logistics.

### 6.14 Maintainability

Subsea equipment assemblies should be designed to be retrievable. The method for retrieval of independently retrievable components should be by ROV, with divers as an exception for shallower water depths, including ROV/ROT tooling if required.

Equipment design should be influenced by maintenance requirements.

— Equipment components requiring periodic inspection and/or maintenance at surface should be designed to be independently retrievable.

— Components subject to wear under normal operating conditions that require maintenance and/or intervention should be designed and configured in a location that accommodates repair or replacement within the parent equipment or assembly.

— Equipment components to be retrieved for periodic inspection and/or maintenance at surface should be designed to be independently retrievable.

— Method for retrieval of independently retrievable components should be by ROV, preferably, with any associated ROV tooling if required.

— A method of parking flying leads should be provided in the vicinity of all independently retrievable components.

— All equipment and components of a like design should be designed and fabricated such that they are interchangeable.

— ROV/ROT tooling and interfaces should comply with API 17H.

The manufacturer should document instructions and requirements concerning maintenance and preservation of equipment.

## 7 Technology Management

### 7.1 Development and Qualification

Equipment, methodologies, and modes of operation classified as new or modified technology (or existing technology to be used in a new application) should be suitably qualified prior to use. Both API 17N and DNV-RP-A203 [30] provide guidance on this topic.

### 7.2 Obsolescence Management

Obsolescence of equipment is inevitable and depending on the design basis, it may not be possible to avoid some replacement components becoming unavailable during the field life of the subsea system. Electronic equipment is particularly prone to this. The negative impacts of obsolescence can be mitigated and/or deferred through a proactive approach, e.g. a robust sparing strategy. As obsolescence management is a continuous activity during field life, a comprehensive obsolescence management strategy and plan should be developed, during the project development phase, that covers all phases of the operation of the equipment through to decommissioning.

The obsolescence management strategy and plan should cover the following areas:

a) design of new products;

b) new technology insertion into existing products;

c) support and maintenance of legacy products.

IEC 62402 [49] provides generic guidance for establishing a framework for obsolescence management and for planning a cost-effective obsolescence management process that is applicable through all phases of the product life cycle, wherein the term “product” includes:

— capital equipment;

— infrastructure;

— consumer durables;

— consumables;

— software products.

As described in OTC 25872-MS [76], two Joint Operator Specification documents—3428A [63] and 3428B [66]—have been created by a joint industry effort, in order to assist the application of IEC 62402 [49] to subsea equipment.

Additional specific guidance on managing obsolescence in subsea systems is also available in Energy Institute’s publication entitled *Guidelines for the management of obsolescence in subsea facilities* [44].

# 8 Manufacture through Commissioning

## 8.1 Reliability, Integrity, and Technical Risk Management

Reliability, integrity, and technical risk management during manufacture, assembly, testing, installation, and commissioning/systems completion is at a procedural level. Implementation of these can be performed by the operator subsea system project team and/or by the supplier/contractor. Further information and guidance on this topic is contained in API 17N.

## 8.2 Manufacture

To avoid the introduction of manufacturing defects and errors, all equipment should be manufactured according to the manufacturer’s quality program and API Q1. API Q1 establishes the API quality system requirements necessary for organizations to consistently manufacture products in accordance with API or other specifications. This specification also sets requirements for all organizations operating under the API Monogram Program. API Q1 applies to those activities that otherwise may be considered a service (such as heat treatment, threading, or testing) if these activities or their results are identified as (or with) an API monogrammable product. Additionally, organizations that supply services should meet the requirements of API Q2.

Guidance on the documentation typically required to be provided by the equipment manufacturer can be found in NORSOK Z-018 [74]. Much of this documentation will usually be incorporated into the overarching system operating documents, as described in NORSOK Z-001 [73].

## 8.3 Assembly

All components, including spares, should be tested for ease of assembly, handling, and interchangeability. Interface checks should be made under static and dynamic conditions.

Jigs and dummies may be used where testing of actual interface components is not practical. It is, however, recommended that the actual equipment be used where feasible. For large orders with identical equipment items, testing should be carried out on the initially produced equipment as a minimum.

Fit tests should be performed in such a way as to prove the guidance and orientation features of the system. In certain cases it is necessary to perform wet-simulation testing in order to prove correct functioning of components and systems underwater.

Certain areas can require cycle testing and make-break testing to prove repeatability of function for new or unqualified designs. Prime targets for this type of testing are valve functions, data transfer functions, hydraulic and chemical connector interfaces, and tooling functions.

Misalignment checks should consider stack-up tolerance, stack-up elevation, horizontal plane orientation and angular alignment. Equipment with self-alignment features should intentionally be misaligned to verify its alignment capability.

Functional checks should include makeup, normal emergency release, reversibility, repeatability, and pressure integrity. The sequence and items to be tested are normally individual components, running tools, subsystems, and the total system assembly.

## 8.4 Testing

Onshore and preinstallation testing can detect early failures in an accessible environment, allowing efficient recording and rectification. Testing should not be a series of isolated test activities but rather a series of related tests that are progressively executed as part of a clearly defined overall project testing strategy and test plan that ensures subsea equipment reliability. The test plan should cover all onshore and preinstallation testing requirements on each subsystem, including the:

— sequence and definition of tests,

— testing requirements for all phases of field life,

— relevant regional and company specific test requirements,

— hardware and software interfaces.

Various tests are typically undertaken on subsea equipment, in order to demonstrate that the numerous components, assemblies, and systems have been manufactured in accordance with the specified requirements and are suitable for the intended use.

Performance tests may be appropriate and can supply data on response-time measurements, operating pressures, fluid volumes, and fault-finding and operation of shutdown systems. Cycle testing and make-break testing should be implemented to prove repeatability and operational life on unqualified designs. Reliability growth testing and accelerated life testing should be performed to validate reliability performance targets.

The following terminology is defined in Annex A (together with examples) to promote uniform usage of the various testing terms commonly used throughout the API 17 series of documents:

— factory acceptance test (FAT);

— extended factory acceptance test (EFAT);

— interchangeability test (ICT)—typically performed as part of EFAT or SFT;

— SFT;

— SIT;

— site received test (SRT);

— predeployment test (PDT).

NOTE Tests may also include simulations of actual field and environmental conditions for some or all phases or modes of operations, from installation through maintenance. Special tests may be needed for handling and transport, dynamic loading, and backup systems.

### 8.5 Installation

The methods and equipment used for installation of the subsea equipment should ensure safe and reliable performance of installation operations.

DNV-RP-H103 [37] provides guidance for modelling and analysis of marine operations, in particular for lifting operations including lifting through the wave zone and lowering of objects in deep water to landing on the seabed.

Additional references are DNVGL-ST-N001 [40] for load transfer operations, sea transport operations, and lifting operations and DNV-RP-H201 [38] and ISO 13535 [57] for guidance on lifting appliances.

Service supply organizations' quality management systems should meet the requirements of API Q2.

### 8.6 Commissioning

Although the vernacular term "commissioning" is still widely used throughout the industry, this phase of the project activities is increasingly referred to by the more comprehensive term "systems completion" of which commissioning is a subpart, as explained below.

As described in API 1FSC [14] systems completion includes:

— factory acceptance testing (insofar as the systems completion process is reliant on the completion of the various tests performed prior to equipment deployment, which in the case of subsea equipment typically involves more than just FAT per se, as described in 8.4);

— verification of mechanical completion (which is the point where field construction/installation is complete and mechanical integrity has been verified);

— precommissioning (which involves activities to verify that the equipment is in the required state of readiness for full dynamic testing), sometimes also referred to as "static commissioning";

— commissioning (which involves activities undertaken to verify dynamically that the system is ready for start-up), sometimes also referred to as "dynamic commissioning";

— start-up [which involves the introduction of process fluids (normally hydrocarbons) into the system];

— performance testing (which involves operating the facilities to perform tests vs the design/contract parameters).

Following successful completion of the performance testing, responsibility for the facility is typically transferred from the project team to the operations group.

## 9 Operations

### 9.1 Integrity Management

The ongoing condition of the subsea equipment should be monitored via a combination of assessment of the data available via the subsea control system, performance of periodic underwater inspections, corrosion control, condition monitoring (hydraulic and electrical), and routine integrity testing of critical equipment such as tree valves.

Specific guidance on integrity management data collection is contained in API 17N.

An initial integrity management status inspection should be performed within the early life of a subsea facility to define the initial condition of the facility and compared against known and potential hazards. Engineered barriers of subsea system should be demonstrated to be fit for service. Subsea emergency response procedures should include procedures and techniques for implementation of repair and restoration of an operable subsea system. Subsea systems integrity performance should be reviewed periodically. Monitoring and inspecting subsea system activities should be prioritized based on outcomes of risk assessments and be reassessed based on the results of data analysis.

API 17N provides an understanding of how to manage an appropriate level of reliability and integrity throughout the life cycle of subsea systems and to recognize the trade-offs between up front reliability, integrity, and engineering vs operational integrity management and maintenance.

The Energy Institute's *Guidelines for the management of integrity of subsea facilities* [43] and DNVGL-RP-0002 [39] both provide useful specific guidance regarding the integrity management of subsea systems.

DNV-RP-F302 [36] provides a summary of industry experiences and knowledge regarding subsea leak detection systems, which can be used as a technical reference.

NORSOK U-009 [72] provides useful guidance regarding the issues and considerations surrounding the use of subsea systems beyond their originally specified service life.

API 14H [20] provides guidance on in situ testing of underwater safety valves (USVs) on subsea trees.

## 9.2 Production Management

Routine operation of the subsea system requires careful control of all of the relevant operating parameters. Subsea production systems (vs subsea water/gas injection systems) involve multiphase flow and therefore should be carefully managed with respect to a number of related issues, including start-up, shutdown, and solids management.

Most subsea production systems rely on some level of chemical injection as part of the solids management strategy; therefore, particular care should be taken with the management of the chemical injection system, especially with respect to blocking lines/injection points as described in API TR5 [6] and API TR6 [7].

Production optimization and long-term reservoir management are also typically more challenging for subsea production systems than for production systems using dry trees, e.g. well testing of subsea wells.

## 9.3 Seabed and Surface Equipment Maintenance

Various maintenance tasks can be performed on equipment located on or near the seabed (i.e. choke inserts, control modules, valves, flowmeters, manifolds, templates, etc.) by modular replacement or via in situ repairs by ROV/divers. IMCA D044 [48] provides guidance regarding isolation and intervention during diver access to subsea systems.

Surface equipment (i.e. production control system components, chemical injection systems, etc.) should be maintained via implementation of a routine maintenance program.

### 9.4 Failure Reporting

A failure reporting process should be in place, and all equipment failures should be communicated back to the original equipment manufacturer (OEM).

## 10 Well Intervention

Where a well is accessed vertically, appropriate subsea or surface BOP equipment should be employed that satisfies the required service conditions and conforms with accepted industry practices and applicable regulations.

Subsea wells should be safely secured prior to commencing any well intervention involving potential exposure to live well fluids. Refer to 5.3.6 for guidance on barrier considerations.

Refer to API 17G for the design, manufacture, testing, and operation of C/WO riser systems.

Extreme care should be taken when lowering and landing tools that connect to the subsea tree and/or wellhead, to minimize potential damage to installed components. If possible, the rig or surface vessel should be displaced to a position offset from the center of the well when handling and running packages, in order to reduce the risk of dropping objects or debris onto the well or adjacent components.

After completion of the well intervention, downhole and tree components should be reinstalled and tested in accordance with the relevant installation procedures.

The well control during a well intervention should only be possible via the workover control system. It should be possible to initiate a shutdown of associated neighboring wells from the well intervention vessel by reliable communication with the host facility.

All subsea tree valves that can prevent downhole access in the event of hydraulic failure should be equipped with a mechanical override feature.

## 11 Decommissioning

The variable elements related to decommissioning are the plugging and abandonment of wells, any necessary removal of seabed equipment, seabed clean-up, and final survey. The effect on the operating environment, e.g. discharge of hydrocarbons during decommissioning, should be minimized.

The subsea production system should, at decommissioning:

— allow cessation of operations without compromising safety;

— allow production products to be flushed from flowlines, pressure vessels, manifolds, etc.;

— allow any hydrocarbon-containing equipment to be removed or, if left in place, be flushed clean. The flushed fluid should be recovered at the surface to avoid pollution.

When the decision has been made to abandon subsea equipment, the method of abandonment should be reviewed in light of changes to the equipment and removal technology. In certain situations, the equipment may be left in place. If it is to be removed, it is recommended that a subsea survey be conducted to ascertain the physical condition. The integrity of the lifting points and ballasting system, if fitted, is critical. After collecting the desired information, a detailed plan of removal should be developed.

Retrieval of equipment should address the possible presence of naturally occurring radioactive materials (NORM), per API E2 [27].

After the abandonment operation, the site should be surveyed and mapped for remaining equipment, if any.

# Annex A
(informative)

# Generic Testing Terms for Use in API 17-series Documents

## A.1 Introduction

The intention of this annex is to promote uniform usage of various terms commonly used throughout the API 17 series of documents, such as:

— FAT,

— EFAT,

— SFT,

— SIT.

The definitions provided herein use the terms “qualification,” “verification,” and “validation” extensively. These terms can have a very broad application, ranging from activities undertaken on new/unique products (including those based on new technologies) being developed and tested for the first time through to the types of activities applied to routine products being tested post-manufacture in order to confirm compliance with various specified requirements.

Notwithstanding the above, the usage of these three terms is based upon the following existing definitions in ISO 9000:2005 [54].

> ***Qualification Process***
>
> *Process to demonstrate the ability to fulfil specified requirements.*
>
> *NOTE 1 The term “qualified” is used to designate the corresponding status.*
>
> *NOTE 2 Qualification can concern persons, products, processes, or systems.*
>
> *EXAMPLE Auditor qualification process, material qualification process.*
>
> ***Verification***
>
> *Confirmation, through the provision of objective evidence, that specified requirements have been fulfilled.*
>
> *NOTE 1 The term “verified” is used to designate the corresponding status.*
>
> *NOTE 2 Confirmation can comprise activities such as*
>
> — *performing alternative calculations,*
> — *comparing a new design specification with a similar proven design specification,*
> — *undertaking tests and demonstrations, and*
> — *reviewing documents prior to issue.*
>
> ***Validation***
>
> *Confirmation, through the provision of objective evidence, that the requirements for a specific intended use or application have been fulfilled.*
>
> *NOTE 1 The term “validated” is used to designate the corresponding status.*
>
> *NOTE 2 The use conditions for validation can be real or simulated.*

The associated terms of design verification and design validation are based upon the following definitions in API Q1.

***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):*

*a) confirming the accuracy of design results through the performance of alternative calculations,*

*b) review of design output documents independent of activities of design and development,*

*c) comparing new designs to similar proven designs.*

***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):*

*a) prototype tests,*

*b) functional and/or operational tests of production products,*

*c) tests specified by industry standards and/or regulatory requirements,*

*d) field performance tests and reviews.*

Qualification of technology is defined in API 17N, wherein it states that “qualification is the process by which systems are examined and evidence is provided to demonstrate that the technology meets the specified requirements for the intended use.”

API 17N provides guidance on the qualification of new technology (which may be physical equipment, or procedural, in nature) as well as on the qualification of existing/modified technology.

## A.2 Terms for Use in API 17-series Documents (in Alphabetical Order)

### A.2.1 Extended Factory Acceptance Test (EFAT)

**Definition:** **Test(s) conducted to verify that the specified requirements, for a set of interfacing products, have been fulfilled.**

**Typical Activities:** Test(s) conducted (typically by the supplier) to verify that the various physical and functional interfaces involved in mating of individual products are in accordance with the specified requirements.

**Notes:** Typically conducted on individual products that have previously been subjected to FAT. May involve some degree of interchangeability testing. Differs from FAT, in that the product interfaces tested during EFAT are those that typically can/will actually occur at the installation site.

**Examples:** Interfacing of:

— tree with tree running tool (TRT);

— tubing hanger with tubing hanger running tool (THRT);

— tree with wellhead;

— tree with tubing hanger and wellhead;

— installation workover control system (IWOCS) with IWOCS umbilical and tree;

— SCM with subsea tree;

— SCM with MCS;

— MCS with hydraulic power unit (HPU);

— flying leads with subsea umbilical distribution unit (SUDU);

— flying leads with subsea trees;

— casing hangers and seal assemblies with wellhead.

### A.2.2 Factory Acceptance Test (FAT)

**Definition:** **Test(s) conducted to verify that the specified requirements, for a product, have been fulfilled.**

**Typical Activities:** Test(s) conducted (typically by the supplier) to verify that the manufacture of a specific product is in accordance with the specified requirements.

**Notes:** Typically conducted on each individual functional product. Differs from EFAT, in that products tested during FAT are typically installed "as is" at the installation site, i.e. without being disassembled after FAT, and therefore not requiring reassembly/interfacing at the installation site.

**Examples:** FAT per API 17D of:

— subsea tree, per supplier's written specification;

— valves and actuators;

— tree cap;

— tree cap running tool (TCRT);

— TRT;

— flowline connector systems;

— subsea chokes;

— wellhead housing;

— casing hanger;

— hanger seal assembly;

— tubing hanger;

— THRT.

FAT of control system products, per API 17F:

— SCM;

— HPU;

— master control station (MCS);

— hydraulic and electric flying leads (HFLs/EFLs);

— SUDU.

FAT of C/WO riser system and workover control system products, per API 17G.

### A.2.3 First Article

**Definition:** **The first of a product produced using the "normal processes" as will be used to make multiple numbers of the same product.**

**Notes:** As distinct from a prototype, a first article should accurately represent all aspects and functionality of the production model product.

Such a product is suitable for normal use.

**Examples:** The first of a new design of SCM manufactured on a production line and intended for use in the field.

### A.2.4 Interchangeability Test (ICT)

**Definition:** **Test(s) conducted to verify the interchangeability requirements of "identical" products, which may be interfaced with other mating products at the installation site, have been fulfilled.**

**Typical Activities:** Interchangeability can be physically confirmed by:

— testing of physical and functional interfaces between two or more interchangeable products, or

— testing of physical and functional interfaces between an interchangeable product and a test jig (or fixture).

**Notes:** Typically performed as part of EFAT or SFT.

**Examples:** Interchangeability testing of mating trees, tubing hangers, caps and running tools, as referred to in API 17D.

### A.2.5 Pilot

**Definition:** **The first of a product used for an extended period in the intended service in order to validate a concept or process, prior to the manufacture of additional similar products.**

**Notes:** Similar to a prototype, a pilot is usually a "one off" and therefore is often not produced using the exact same processes as will be used to make the actual production model of a product (of which multiple numbers may be produced).

However unlike a prototype, a pilot needs to accurately represent all aspects and functionality of the intended production model product in order to be a valid test and to be suitable for use in the field.

Based on the results gained from the extended field testing of a pilot, it is not uncommon for the actual production model to be somewhat different from the pilot in some aspects.

**Examples:** The Troll Pilot subsea separation system.

### A.2.6 Predeployment Test (PDT)

**Definition:** **Test(s) conducted to verify that the specified requirements, for a product that is ready for deployment, are still fulfilled.**

**Typical Activities:** The first part of the PDT will typically involve completion of an appropriate SRT, which will be followed by preparation of the products for deployment.

PDT typically includes, but is not limited to:

— cleaning of the product;

— visual inspection for damage;

— checking of critical functions.

Following completion of the PDT activities, the product will then be prepared for deployment (e.g. removal of protective covers and test seals, fitting of final seals, precharging of accumulators, pre-pressuring of flying leads).

**Notes:** The extent of the PDT will be dependent on a number of factors, including but not limited to:

— the distance transported;

— the method of transport;

— the duration of the transport;

— exposure to the environment during transport.

**Examples:** PDT would be performed after delivery of a product from an onshore storage site to an offshore installation site.

### A.2.7 Production Model/Production Product

**Definition:** **A product manufactured using the "normal processes" and intended for normal use.**

**Notes:** Often a production model is one of a multiple number of the same product.

The term "production model" is used herein due to its prior use in API 6A [17].

**Examples:** An SCM manufactured on a production line and intended for use in the field.

### A.2.8 Prototype

**Definition:** **A trial product produced to test a concept or process.**

**Notes:** A prototype is usually a “one off” and therefore is often not produced using the exact same processes as will be used to make the actual production model of a product (of which multiple numbers are often produced).

A prototype often does not accurately represent all aspects and functionality of the complete production model/product, as it may only be used to test certain specific aspects of the concept or process.

**Examples:** A prototype gate valve manufactured for the purpose of validating a new design.

### A.2.9 Sample

**Definition:** **A small portion taken from a quantity to give an idea of the whole.**

**Notes:** Samples are usually subjected to some type of inspection and/or testing in order to confirm that specified requirements have been fulfilled.

**Examples:** A number of bolts taken from a larger quantity and tested, prior to use of the bolts in an assembled product.

### A.2.10 Site Received Test (SRT)

**Definition:** **Test(s) conducted to verify that the specified requirements, for a product that has been transported from one site to another, are still fulfilled.**

**Typical Activities:** SRT typically includes, but is not limited to:

— cleaning of the product;

— visual inspection for damage;

— replication of relevant portions of the FAT/EFAT.

**Notes:** The extent of the SRT will be dependent on a number of factors, including but not limited to:

— the distance transported;

— the method of transport;

— the duration of the transport;

— exposure to the environment during transport.

**Examples:** SRT would be performed after delivery of a product:

— from a subsupplier to a supplier, e.g. “delivery acceptance” testing of umbilical components as per API 17E;

— from one supplier site to another supplier site, e.g. transport of an SCM to a tree manufacturing site, for completion of EFAT or SFT;

— from a supplier site to a third-party testing site, e.g. for SFT or SIT;

— from a supplier to a customer.

### A.2.11 System Function Test (SFT)

**Definition:** **Test(s) conducted to validate that the requirements for a specific intended use or application, of a set of products that form a "complete" [1] functional system, have been fulfilled.**

[1] The system may not be totally complete using the actual products to be installed in the field, e.g. a test of the production control system would typically use an umbilical simulator, rather than the actual umbilical itself.

**Typical Activities:** Test(s) conducted [typically by the supplier(s)] to validate that the individual products meet the requirements for a specific intended use, when as operating as part of a "complete" functional system.

**Notes:** Typically involves nondestructive testing performed on an assembly of individual products that have been previously subjected to FAT and EFAT.

Typically performed onshore, but may include shallow and/or deepwater testing if new designs are involved, for which there is insufficient field experience. The requirement for (some or all) testing may be foregone in some cases based on the prior performance of similar "field proven" products, provided there is agreement between the supplier and the customer to do so.

If multiple suppliers are involved, then the test(s) are typically performed under the direction of the customer.

**Examples:** Functional test of the production control system for a subsea tree by testing of the interconnected MCS, HPU, umbilical simulator, SUDU, flying leads, SCM, and subsea tree.

### A.2.12 System Integration Test (SIT)

**Definition:** **Test(s) conducted to validate that the requirements for a specific intended use or application, of a set of products that form an integrated system, have been fulfilled.**

**Typical Activities:** Test(s) conducted (typically under the direction of the customer) to validate that the various interfaces involved in mating of individual products, particularly from different suppliers, meet the requirements for a specific intended use.

**Notes:** Typically involves nondestructive testing performed on an assembly of individual products that have been previously subjected to FAT, EFAT, and SFT.

Typically conducted on the actual products to be used, but may also involve use of test jigs and/or mock-ups of some components.

The requirement for (some or all) testing may be foregone in some cases based on the prior performance of similar "field proven" products, provided there is agreement between the supplier and the customer to do so.

Typically involves a high emphasis on testing of procedures (e.g. covering installation, retrieval, diagnostic, maintenance, and contingency procedures), as well as training of personnel (from both the installation and operation teams). Typically performed onshore, but may include shallow and/or deepwater testing if new designs are involved for which there is insufficient field experience.

**Examples:** Operation of ROV tooling, including tests for ROV accessibility (using a mock-up or real ROV) and tolerance requirements.

Installation and retrieval of flowline jumpers between subsea trees and the manifold. Deployment and connection of flying leads between the SUDU and subsea trees/manifold.

### A.2.13 Validation Testing

**Definition:** **Test(s) conducted to confirm that the requirements for a specific intended use (1) or application of a product have been fulfilled.**

(1) The "intended use" should include use in all situations that are reasonably foreseeable, including situations involving common failures.

**Typical Activities:** Test(s) conducted as part of validation type activities during product development, using prototypes, pilots, and/or first articles, under conditions designed to replicate key service parameters.

Test(s) conducted as part of SFT and/or SIT of pilots, first articles, or production models, under conditions designed to replicate key service parameters.

**Notes:** If performed as part of a product development activity, then validation testing often results in significant degradation, or the destruction, of the product being tested.

May include "product family validation" as explained in API 17D.

Typically performed onshore, but may include shallow and/or deepwater testing.

A product that undergoes a substantive change (e.g. of design or manufacturing process) becomes a new product requiring revalidation as explained in API 6A [17].

Multiple validations should be carried out if there are different intended uses of the same product or if the intended use changes after the product has already been validated.

The requirement for (some or all) validation testing may be foregone in some cases based on the prior performance of similar "field proven" products, provided there is agreement between the supplier and the customer to do so.

**Examples:** Validation testing of subsea wellhead and tree products, per API 17D.

"Product family validation," per API 17D.

Validation testing of tree cap, per API 17D.

Validation testing of flowline connector systems per API 17D.

Validation testing of USVs per API 6AV1 [18].

### A.2.14 Verification Testing

**Definition:** **Test(s) conducted to confirm that the specified requirements for a product have been fulfilled.**

**Typical Activities:** Test(s) conducted as part of verification type activities during product development using prototypes, pilots, and/or first articles.

Test(s) conducted as part of FAT and/or EFAT of pilots, first articles, or production models.

**Notes:** If performed as part of a product development activity, then verification testing may result in significant degradation, or the destruction, of the product being tested.

If performed as part of an FAT or EFAT activity of a first article or production model, then verification testing does not usually result in a significant degradation, or the destruction, of the product being tested, except in the case where a sample is being tested, e.g. a subsea umbilical sample from a main production run.

A product that undergoes a substantive change (e.g. of design or manufacturing process) becomes a new product requiring reverification.

**Examples:** Verification testing of a production length of umbilical as per API 17E.

# Bibliography


**API 17-series Technical Reports**

[1] API Technical Report 1PER15K-1, *Protocol for Verification and Validation of High-pressure High-temperature Equipment*

[2] API Technical Report 17TR1, *Evaluation Standard for Internal Pressure Sheath Polymers for High Temperature Flexible Pipes*

[3] API Technical Report 17TR2, *The Ageing of PA-11 in Flexible Pipes*

[4] API Technical Report 17TR3, *An Evaluation of the Risks and Benefits of Penetrations in Subsea Wellheads Below the BOP Stack*

[5] API Technical Report 17TR4, *Subsea Equipment Pressure Ratings*

[6] API Technical Report 17TR5, *Avoidance of Blockages in Subsea Production Control and Chemical Injection Systems*

[7] API Technical Report 17TR6, *Attributes of Production Chemicals in Subsea Production Systems*

[8] API Technical Report 17TR8, *High-Pressure High-Temperature Design Guidelines*

[9] API Technical Report 17TR10, *Subsea Umbilical Termination (SUT) Design Recommendations*

[10] API Technical Report 17TR11, *Pressure Effects on Subsea Hardware During Flowline Pressure Testing in Deep Water*

[11] API Technical Report 17TR12, *Consideration of External Pressure in the Design and Pressure Rating of Subsea Equipment*

[12] API Technical Report 17TR13, *General Overview of Subsea Production Systems*

[13] API Technical Report 17TR15, *API 17H Hydraulic Interfaces for Hot Stabs*

**Additional API Documents**

[14] API Recommended Practice 1FSC, *Facilities Systems Completion Planning and Execution*

[15] API Recommended Practice 2A-WSD, *Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design*

[16] API Standard 2RD, *Dynamic Risers for Floating Production Systems*

[17] API Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

[18] API Specification 6AV1, *Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service*

[19] API Recommended Practice 14E, *Recommended Practice for Design and installation of Offshore Production Platform Piping Systems*

[20] API Recommended Practice 14H, *Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore*

[21] API Recommended Practice 16Q, *Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*

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

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

[24] API Recommended Practice 96, *Deepwater Well Design and Construction*

[25] API Recommended Practice 1110, *Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide*

[26] API Recommended Practice 1111, *Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)*

[27] API Bulletin E2, *Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production*

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

**Additional (Non-API) Documents**

[29] DNV Standard for Certification No. 2.7-3 [1], *Portable offshore units*

[30] DNV-OS-F201, *Dynamic risers*

[31] DNV-OS-H205, *Lifting operations*

[32] DNV-RP-A203, *Technology qualification*

[33] DNV-RP-B401, *Cathodic protection design*

[34] DNV-RP-F112, *Design of duplex stainless steel subsea equipment exposed to cathodic protection*

[35] DNV-RP-F301, *Subsea separator structural design*

[36] DNV-RP-F302, *Offshore leak detection*

[37] DNV-RP-H103, *Modelling and analysis of marine operations*

[38] DNV-RP-H201, *Lifting appliances used in subsea operations*

[39] DNVGL-RP-0002, *Integrity management of subsea production systems*

[40] DNVGL-ST-N001, *Marine operations and marine warranty*

[41] DNVGL-RP-0034, *Steel forgings for subsea applications*

[42] DNVGL-RP-0142, *Wellhead fatigue analysis*

[43] Energy Institute [2], *Guidelines for the management of integrity of subsea facilities*

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

[44] Energy Institute, *Guidelines for the management of obsolescence in subsea facilities*

[45] EEMUA Publication 194 [3], *Guidelines for materials selection and corrosion control for subsea oil and gas production equipment*

[46] IEC 61160 [4]/EN 61160 [5], *Design review*

[47] IEC 61508, *Functional safety or electrical/electronic/programmable electronic safety-related systems*

[48] IEC 61511-1, *Functional safety—Safety instrumented systems for the process industry sector—Part 1: Framework, definitions, system, hardware and application programming requirements*

[49] IEC 62402, *Obsolescence management—Application guide*

[50] IMCA D044 [6], *Isolation and intervention: Diver access to subsea systems*

[51] INCOSE [7], *Systems Engineering Handbook: A Guide for System Life Cycle Processes and Activities*

[52] ISO 8501-1 [8], *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. Informative supplement to part 1: Representative photographic examples of the change of appearance imparted to steel when blast-cleaned with different abrasives*

[53] ISO 8503 (all parts), *Preparation of steel substrates before application of paints and related products—Surface roughness characteristics of blast-cleaned steel substrates*

[54] ISO 9000:2005, *Quality management systems—Fundamentals and vocabulary*

[55] ISO 9588, *Metallic and other inorganic coatings—Post-coating treatments of iron or steel to reduce the risk of hydrogen embrittlement*

[56] ISO 12944 (all parts), *Paints and varnishes—Corrosion protection of steel structures by protective paint systems*

[57] ISO 13535, *Petroleum and natural gas industries—Drilling and production equipment—Hoisting equipment*

[58] ISO 14224, *Petroleum, petrochemical and natural gas industries—Collection and exchange of reliability and maintenance data for equipment*

---

[2] Energy Institute, formerly the Institute of Petroleum, 61 New Cavendish Street, London W1G 7AR, UK, www.energyinst.org.

[3] Engineering Equipment and Materials Users Association, 16 Black Friars Lane, Second Floor, London EC4V 6EB, United Kingdom, www.eemua.org.

[4] International Electrotechnical Commission, 3, rue de Varembé, 1st Floor, PO Box 131, CH-1211, Geneva 20, Switzerland, www.iec.ch.

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

[6] International Marine Contractors Association, 52 Grosvenor Gardens, London SW1W 0AU, United Kingdom, www.imca-int.com.

[7] International Council on Systems Engineering, 7670 Opportunity Rd, Suite 220, San Diego, California 92111, www.incose.org.

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

[59] ISO/IEC/IEEE [9] 15288, *Systems and software engineering—System life cycle processes*

[60] ISO 17776, *Petroleum and natural gas industries—Offshore production installations—Major accident hazard management during the design of new installations*

[61] ISO 19901-2, *Petroleum and natural gas industries—Specific requirements for offshore structures—Part 2: Seismic design procedures and criteria*

[62] ISO 19901-4, *Petroleum and natural gas industries—Specific requirements for offshore structures—Part 4: Geotechnical and foundation design considerations*

[63] ISO 19901-5, *Petroleum and natural gas industries—Specific requirements for offshore structures—Part 5: Weight control during engineering and construction*

[64] ISO 21457, *Petroleum, petrochemical and natural gas industries—Materials selection and corrosion control for oil and gas production systems*

[65] Joint Operator Specification 3428A, *Obsolescence Management for Subsea Production Control Systems* (available at www.subseaobs.com per OTC 25872-MS [78])

[66] Joint Operator Obsolescence Management Specification 3428B, *Recommended Practice for Obsolescence Management* (available at www.subseaobs.com per OTC 25872-MS [78])

[67] MITRE Corporation [10], *Systems Engineering Guide*

[68] NACE MR0175 [11]/ISO 15156, *Petroleum, petrochemical, and natural gas industries—Materials for use in $H_2S$-containing environments in oil and gas production*

[69] NACE SP0176, *Corrosion control of submerged areas of permanently installed steel offshore structures associated with petroleum production*

[70] NORSOK D-010 [12], *Well integrity in drilling and well operations*

[71] NORSOK U-001, *Subsea production systems*

[72] NORSOK U-009, *Life extension for subsea systems*

[73] NORSOK Z-001, *Documentation for operation*

[74] NORSOK Z-018, *Supplier's documentation of equipment*

[75] Oil & Gas UK [13], *Well Life Cycle Integrity Guidelines*

[76] OLF 117 [14], *Norwegian Oil and Gas Recommended Guidelines for Well Integrity*

[77] OTC 14010, *Flow Assurance: A $\pi^3$ Discipline*, paper by Lloyd D. Brown, Conoco, Inc., 2002 Offshore Technology Conference

---

9 Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.

10 The MITRE Corporation, 202 Burlington Road, Bedford, MA 01730 & 7515 Colshire Drive, McLean, VA 22102, www.mitre.org.

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

12 Standards Norway, PO Box 242, NO-1326 Lysaker, Norway, www.standard.no/en/.

13 Oil & Gas UK, 6th Floor East, Portland House, Bressenden Place, London SW1E 5BH, United Kingdom, http://oilandgasuk.co.uk.

14 Norwegian Oil and Gas Association, PO Box 8065, 4068 Stavanger, Norway, www.norskoljeoggass.no/en.

[78] OTC 25872-MS, *Managing obsolescence risk for subsea production control systems through the implementation of a proactive obsolescence management system*

[79] Systems Engineering Body of Knowledge (SEBoK) at http://sebokwiki.org

AMERICAN PETROLEUM INSTITUTE

1220 L Street, NW
Washington, DC 20005-4070
USA

202-682-8000

**Additional copies are available online at www.api.org/pubs**

| | | |
|---|---|---|
| Phone Orders: | 1-800-854-7179 | (Toll-free in the U.S. and Canada) |
| | 303-397-7956 | (Local and International) |
| Fax Orders: | 303-397-2740 | |

Information about API publications, programs and services is available on the web at www.api.org.

**Product No. GX17A05**