Recommended Practice for Subsea Structures and Manifolds

API RECOMMENDED PRACTICE 17P
SECOND EDITION, JANUARY 2019
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 ensure 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 document is solely responsible for complying with all the applicable requirements of that document. API does not represent, warrant, or guarantee that such products do in fact conform to the applicable API publication.

Users of this Recommended Practice should not rely exclusively on the information contained in this document. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein.
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.

The verbal forms used to express the provisions in this document are as follows.

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

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

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

Can: As used in a standard, “can” denotes a statement of possibility or capability.

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

1. Scope .......................................................................................................................... 1
2. Normative References ..................................................................................................... 2
3. Abbreviations and Definitions ......................................................................................... 4
   3.1 Definitions .................................................................................................................. 4
   3.2 Abbreviations ............................................................................................................. 7
4. System Design ................................................................................................................ 9
   4.1 General ...................................................................................................................... 9
   4.2 Standalone Structures .............................................................................................. 13
   4.3 Pipeline Structures .................................................................................................. 14
   4.4 Template Systems .................................................................................................... 14
5. Detail Design ................................................................................................................ 16
   5.1 General .................................................................................................................... 16
   5.2 Loads ....................................................................................................................... 18
   5.3 Piping Systems ....................................................................................................... 20
   5.4 Structural Design .................................................................................................... 23
   5.5 Foundation Design .................................................................................................. 25
   5.6 Pad Eyes and Other Lifting Devices ....................................................................... 30
   5.7 Subsea Marking ....................................................................................................... 30
   5.8 Components ............................................................................................................ 30
6. Materials and Welding .................................................................................................... 31
   6.1 Materials .................................................................................................................. 31
   6.2 Welding .................................................................................................................... 37
   6.3 General and NDT Personnel Qualification ................................................................ 46
7. Material Traceability ...................................................................................................... 46
8. Transportation and Preservation ..................................................................................... 46
   8.1 General .................................................................................................................... 46
   8.2 Storage and Preservation Procedure ....................................................................... 47
   8.3 Sea-fastening ......................................................................................................... 47
9. Installation/Retrieval of Structures and Components ................................................... 47
   9.1 Installation/Retrieval General Requirements ......................................................... 47
   9.2 Installation Method and Tools .................................................................................. 49
   9.3 Hook-up and Commissioning ................................................................................... 49
   9.4 Testing Requirements .............................................................................................. 50
   9.5 Intervention Requirements ...................................................................................... 50
10. Operation and Maintenance ......................................................................................... 51
    10.1 Operability .............................................................................................................. 51
    10.2 Maintenance .......................................................................................................... 52
11. Abandonment ............................................................................................................... 53
    11.1 General .................................................................................................................. 53
    11.2 Decommissioning .................................................................................................. 53
    11.3 Manifolds .............................................................................................................. 54
    11.4 Templates .............................................................................................................. 54
    11.5 Foundations .......................................................................................................... 55
Contents

12 Qualification, Verification, Validation, and Testing ................................................................. 55
  12.1 Design Verification ............................................................................................................. 55
  12.2 Design Validation ............................................................................................................. 58

Annex A (informative) Typical manifold data sheet ................................................................. 60

Bibliography ............................................................................................................................. 62

Figures
  1 Example of Some Typical Subsea Structures ........................................................................ 2
  2 Typical Template System ...................................................................................................... 15

Tables
  1 Industry Standards for Manifold Components ..................................................................... 31
  2 Reference Standards for Seamless and Welded Pipe in Carbon and Low-alloy Steel ......... 32
  3 Reference Standards for Seamless and Welded Manifold Pipe in Stainless Steel Alloy ....... 32
  4 Reference Standards for Seamless, Welded, and Forged Fittings in Carbon and Low-alloy Steel ... 33
  5 Reference Standards for Seamless, Forged and Welded Manifold Fittings in Stainless Steel Alloy ... 34
  6 Testing of Qualification and Production Bends for Stainless Steels, Nickel Alloys and Clad Pipe ... 35
  7 Material Standards for Forged Pressure-containing Components ........................................... 36
  8 Limitations in Sulfur Content, S, in Carbon and Low-alloy Steels ....................................... 37
  9 Impact Test Requirements .................................................................................................... 43
 10 Hardness Limitations to Avoid Hydrogen Embrittlement Under Cathodic Protection ............. 44
Introduction

The first edition of API 17P was published on January 30, 2013. The first edition of API RP 17P was a U.S. National Adoption of ISO 13628-15. The first edition of ISO 13628-15 was published in the third quarter of 2011 and was created by a joint API/ISO task group. This second edition of API 17P has been completely rewritten as recommended practice (RP). While the scope is similar to the first edition of API RP 17P, the material section has been rewritten and Sections 8 through 12 have been added.

The intent of this RP is to provide guidance for the specification, design, construction, transportation, installation, maintenance, and operation of subsea structures and manifolds.

This standard is under the jurisdiction of API Subcommittee 17 on Subsea Production Systems. 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.

This is the Second Edition.

API Subcommittee 17 documents consist of the following:

— Recommended Practice 17A, Design and Operation of Subsea Production Systems—General Requirements and Recommendations
— Recommended Practice 17B, Recommended Practice for Flexible Pipe
— Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment
— Specification 17E, Specification for Subsea Umbilicals
— Standard 17F, Standard for Subsea Production Control Systems
— Recommended Practice 17G, Recommended Practice for Completion/Workover Risers
— Recommended Practice 17H, Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems
— Specification 17J, Specification for Unbonded Flexible Pipe
— Specification 17K, Specification for Bonded Flexible Pipe
— Specification 17L1, Specification for Flexible Pipe Ancillary Equipment
— Recommended Practice 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment
— Recommended Practice 17N, Recommended Practice on Subsea Production System Reliability, Technical Risk, and Integrity Management
— Standard 17O, Standard for Subsea High Integrity Pressure Protection Systems (HIPPS)
— Recommended Practice 17P, Design and Operation of Subsea Production Systems—Subsea Structures and Manifolds
— Recommended Practice 17Q, Recommended Practice on Subsea Equipment Qualification
— Recommended Practice 17R, Recommended Practice for Flowline Connectors and Jumpers
— Recommended Practice 17S, Recommended Practice for the Design, Testing, and Operation of Subsea Multiphase Flow Meters
— Recommended Practice 17U, Recommended Practice for Wet and Dry Thermal Insulation of Subsea Flowlines and Equipment
— Recommended Practice 17V, Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications
— Recommended Practice 17W, Recommended Practice for Subsea Capping Stacks
— Technical Report 17TR1, Evaluation Standard for Internal Pressure Sheath Polymers for High Temperature Flexible Pipes
— Technical Report 17TR4, Subsea Equipment Pressure Ratings
— Technical Report 17TR5, Avoidance of Blockages in Subsea Production Control and Chemical Injection Systems
— Technical Report 17TR6, Attributes of Production Chemicals in Subsea Production Systems
— Technical Report 17TR7, Verification and Validation of Subsea Connectors
— Technical Report 17TR8, High-pressure High-temperature Design Guidelines
— Technical Report 17TR9, Umbilical Termination Assembly (UTA) Selection and Sizing Recommendations
— Technical Report 17TR10, Subsea Umbilical Termination (SUT) Design Recommendations
— Technical Report 17TR11, Pressure Effects on Subsea Hardware During Flowline Pressure Testing in Deep Water
— Technical Report 17TR12, Consideration of External Pressure in the Design and Pressure Rating of Subsea Equipment
— Technical Report 17TR13, General Overview of Subsea Production Systems
— Technical Report 17TR15, API 17H Hydraulic Interfaces for Hot Stabs

It is important that users of this part of API 17 be aware that further or differing requirements can be needed for individual applications. This part of API 17 is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment engineering solutions for the individual application. This can be particularly applicable if there is innovative or developing technology. If an alternative is offered, it is the responsibility of the vendor to identify any variations from this part of API 17 and provide details.
Recommended Practice for Subsea Structures and Manifolds

1 Scope

This document addresses recommendations for subsea structures and manifolds, within the frameworks set forth by recognized and accepted industry specifications and standards.

Equipment within the scope of this document is listed below (see Figure 1):

a) the following structural components and piping systems of subsea production systems:
   — production and injection manifolds,
   — modular and integrated single satellite and multi-well templates,
   — subsea processing and subsea boosting stations,
   — flow control modules,
   — flowline riser bases and export riser bases,
   — pipeline end manifolds (PLEM),
   — pipeline end terminations (PLET),
   — T- and Y-connections,
   — subsea isolation valves (SSIV);

b) the following structural components of subsea production system:
   — subsea controls and distribution structures,
   — other subsea structures;

c) protection structures associated with the above components;

d) foundations and mounting bases to support above structures;

The following components and their applications are outside the scope of this document:

— pipeline and manifold valves;
— flowline and tie-in connectors;
— choke valves;
— flow control valves;
— multi-phase flow meters;
— pressure vessels;
— production control systems.

NOTE General information regarding these topics can be found in additional publications, such as API 17A, API 17E, and API 2C.
2 Normative References

The following normative documents contain provisions that, through reference in this text, constitute provisions of this standard. For dated references, subsequent amendments to or revisions of any of these publications do not apply. For undated references, the latest edition of the normative document applies.

API 2A-WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design

API 6A, Specification for Wellhead and Christmas Tree Equipment

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

API 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment
API 17H, *Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems*

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

API 20F, *Corrosion Resistant Bolting for Use in the Petroleum and Natural Gas Industries*

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

ASNT SNT-TC-1A, *Personnel Qualification and Certification in Nondestructive Testing*

ASTM A36, *Standard Specification for Carbon Structural Steel*

ASTM A193, *Standard Specification for Alloy-Steel and Stainless Steel Bolting for High Temperature or High Pressure Service and Other Special Purpose Applications*

ASTM A320, *Standard Specification for Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service*

ASTM A388, *Standard Practice for Ultrasonic Examination of Steel Forgings*


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

ISO 9606 (all parts), *Qualification test of welders—Fusion welding*

ISO 9712, *Non-destructive testing—Qualification and certification of NDT personnel—General principles*

ISO 10474, *Steel and steel product—Inspection documents*

ISO 14731:2006, *Welding coordination—Tasks and responsibilities*

ISO 14732:2013, *Welding personnel—Qualification testing of welding operators*

ISO 15156 (all parts), *Petroleum and natural gas industries—Materials for use in H₂S-containing environments in oil and gas production*

ISO 15590-1, *Petroleum and natural gas industries—Induction bends, fittings and flanges for pipeline transportation systems—Part 1: Induction bends*

ISO 15609 (all parts), *Specification and qualification of welding procedures for metallic materials—Welding procedure specification*

ISO 15614 (all parts), *Specification and qualification of welding procedures for metallic materials—Welding procedure test*


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

EN 10228-3, *Non-destructive testing of steel forgings—Part 3: Ultrasonic testing of ferritic or martensitic steel forgings*

NS 477, *Welding—Rules for qualification of welding inspectors*
3 Abbreviations and Definitions

3.1 Definitions

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

3.1.1 barrier
element forming part of a pressure-containing envelope that is designed to prevent unintentional flow of produced/injected fluids, particularly to the external environment.

3.1.2 carbon steel
full range of carbon, carbon-manganese, and low-alloy steels used in the construction of conventional oilfield equipment.

3.1.3 cluster manifold
independent structure used to comingle produced fluids or distribute injection fluids to or from one or more wells.

NOTE There are no wells positioned on a cluster manifold.

3.1.4 corrosion-resistant alloy
corrosion-resistant alloy (CRA)
alloy that is intended to be resistant to general and localized corrosion in oilfield environments that are corrosive to carbon steels.

NOTE This definition is in accordance with ISO 15156 (all parts) and is intended to include materials such as stainless steels and nickel base alloys. Other ISO documents can have other definitions.

3.1.5 drilling template
drilling template
multi-well template used as a drilling guide to predrill wells prior to installing a surface facility.

NOTE The wells are typically tied back to the surface facility during completion. The wells can also be completed subsea, with individual risers back to the surface.

3.1.6 driven pile
jetted pile
typically, a tall steel cylindrical structure, with or without internal stiffener system, used to support subsea structures.

NOTE Driven piles are usually driven into the sea-floor with impact hammers, while jetted piles rely on jetting the soil at the lower end of the pile.

3.1.7 end user
operating facility or operating license for which the system is being purchased.

NOTE Due to differing ownership solutions, the end user may not be the same entity as the purchasing party.
3.1.8 **engineered lift plan**
A lifting plan that ensures controls and safe guards are in place such that no components experience conditions above code requirements.

3.1.9 **inline tee**
A system of piping and valves used to make a subsea connection at the middle of a pipeline, and generally integral to the pipeline.

**NOTE** The pipeline may be used to transport produced fluids or to distribute injected fluids.

3.1.10 **low-alloy steel**
Steel containing less than 5% mass fraction total alloying elements, or steels with less than 11% mass fraction chromium, but more than that specified for carbon steel.

3.1.11 **manifold**
A system of headers, branched piping, and valves used to gather produced fluids or to distribute injected fluids in subsea oil and gas production systems.

**NOTE** A manifold system can also provide for well testing and well servicing. The associated equipment can include valves, pumps, compressors, connectors for pipeline and tree interfaces, chokes for flow control, and through-flow loop (TFL) diverters. The manifold system can include control system equipment, such as a distribution system for hydraulic and electrical functions, as well as providing interface connections to control modules. All or part of the manifold can be integral with the template or can be installed separately at a later date if desired. Manifold headers can include lines for water or chemical injection, gas lift, and well control.

3.1.12 **modular template**
A template installed as one unit or as modules assembled around a base structure (often the first well).

**NOTE** If installed as one unit, the template is of a cantilevered design. If installed as modules, these modules can be of cantilevered design.

3.1.13 **mudmat**
Typically a shallow structure used to support a subsea structure by distributing the load to the seabed via a structural plate and/or shallow skirt.

3.1.14 **pipeline end manifold**
**PLEM**
A system of headers, piping, and valves at the end of a pipeline used to gather produced fluids or to distribute injected fluids in subsea production systems, generally integral to the pipeline and having more than one subsea connection.

3.1.15 **pipeline end termination**
**PLET**
A system of piping and valves, generally integral to the pipeline, used to make a subsea connection at the end of a pipeline.

**NOTE 1** Typically, a PLET has only one subsea connection.

**NOTE 2** The pipeline can be used to transport produced fluids or to distribute injected fluids.
3.1.16  
Pitting resistance equivalent number  
**PREN**  
Index that exists in several variations and usually based on observed resistance to pitting of corrosion-resistant alloys in the presence of chlorides and oxygen, e.g. as found in seawater.

3.1.17  
Protection structure  
Independent or integral structure that protects subsea equipment against damage from dropped objects, fishing gear and other relevant accidental loads.

3.1.18  
Riser base  
Structure that supports a marine production riser or loading terminal, and that serves as a structure through which to react to loads on the riser throughout its service life.

**NOTE**  
A riser base can also include a pipeline connection capability.

3.1.19  
Sealine  
Subsea flowline.

3.1.20  
Sour service  
Service in H₂S-containing fluids.

**NOTE**  
“Sour service” refers to conditions where the H₂S content is such that restrictions as specified in ISO 15156 (all parts) or NACE MR 0175 apply.

3.1.21  
Suction pile  
Typically a tall steel cylindrical structure, open at the bottom and normally closed at the top and used as a foundation for subsea structures.

**NOTE 1**  
The structure can be designed with or without an internal stiffener system and usually has a suction interface.

3.1.22  
Sweet service  
Service in H₂S-free fluids.

3.1.23  
Template  
Seabed structure that provides guidance and support for drilling and includes production/injection piping.

**NOTE 1**  
A template typically comprises a structure that provides a guide for drilling and/or support for other equipment, and provisions for establishing a foundation (piled or gravity-based). It is typically used to group several subsea wells (modular manifold) at a single seabed location.

**NOTE 2**  
Production from the templates can flow to floating production systems, platforms, shore, or other remote facilities.

**NOTE 3**  
Templates can be of a unitized or modular design.

3.1.24  
Type 316  
Austenitic stainless steel alloy.

**EXAMPLE**  
UNS S31600/S31603.
3.1.25
type 6Mo
austenitic stainless steel alloy having PREN ≥ 40 mass fraction and Mo alloying ≥ 6.0 % mass fraction; also refers to nickel alloy having a Mo content in the range 6 % mass fraction to 8 % mass fraction.

3.1.26
type 22Cr duplex
ferritic/austenitic stainless steel alloy with 30 < PREN ≤ 40 and Mo > 1.5 % mass fraction.

EXAMPLE   UNS S31803 and S32205 steels.

3.1.27
type 25Cr duplex
ferritic/austenitic stainless steel alloys with 40 < PREN ≤ 45.

EXAMPLE   S32750 and UNS S32760 steels.

3.1.28
validation
confirmation that the operational requirements for a specific use or application have been fulfilled through the provision of objective evidence.

NOTE   Typically validation is achieved by qualification testing and/or system integration testing.

3.1.29
verification
confirmation that specified design requirements have been fulfilled through the provision of objective evidence.

NOTE   Typically verification is achieved by calculations, design reviews, and hydrostatic testing.

3.2 Abbreviations

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

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACCP</td>
<td>ASNT Central Certification Program</td>
</tr>
<tr>
<td>API</td>
<td>American Petroleum Institute</td>
</tr>
<tr>
<td>ASME</td>
<td>American Society of Mechanical Engineers</td>
</tr>
<tr>
<td>ASTM</td>
<td>American Society for Testing and Materials</td>
</tr>
<tr>
<td>ASNT</td>
<td>American Society of Nondestructive Testing</td>
</tr>
<tr>
<td>AWS</td>
<td>American Welding Society</td>
</tr>
<tr>
<td>BOP</td>
<td>blowout preventer</td>
</tr>
<tr>
<td>BPVC</td>
<td>Boiler and Pressure Vessel Code</td>
</tr>
<tr>
<td>CRA</td>
<td>corrosion-resistant alloy</td>
</tr>
<tr>
<td>CVN</td>
<td>Charpy V-notch</td>
</tr>
<tr>
<td>DAC</td>
<td>distance amplitude curve</td>
</tr>
<tr>
<td>DC</td>
<td>design class</td>
</tr>
<tr>
<td>DNV</td>
<td>Det Norske Veritas</td>
</tr>
<tr>
<td>EWF</td>
<td>European Federation for Welding, Joining and Cutting</td>
</tr>
<tr>
<td>EN</td>
<td>European Norm</td>
</tr>
<tr>
<td>FIV</td>
<td>flow-induced vibration</td>
</tr>
</tbody>
</table>
GMAW  gas metal arc welding
GTAW  gas tungsten arc welding
HAZ  heat-affected zone
HAZOP  hazard and operability analysis
HD  diffusible hydrogen, expressed as ml/100 g deposited metal
HIP  hot isostatic pressed
ID  inner diameter
IIW  International Institute of Welding
IWE  International Welding Engineer
ISO  International Organization for Standardization
LP  liquid penetrant
MC  material class
MDT  minimum design temperature
MPFM  multi-phase flow meter
MPS  Manufacturing Procedure Specification
NDT  nondestructive testing
NORSOK  Norsk Sokkels
P&ID  process and instrumentation diagram
PLEM  pipeline end manifold
PLET  pipeline end termination
PQR  procedure qualification record
PREN  pitting resistance equivalent number
PSL  product specification level
PWHT  post-weld heat treatment
ROT  remotely operated tool
ROV  remotely operated vehicle
SAFOP  safety and operability analysis
SCM  subsea control module
SMYS  specified minimum yield strength
SSIV  subsea isolation valve
TFL  through-flow loop
UNS  Unified Numbering System
UT  ultrasonic testing
VIV  vortex-induced vibration
WM  weld metal
WPS  welding procedure specification
WPQR  weld procedure qualification record
WROV  work-class remotely operated vehicle
XT  christmas tree
4 System Design

4.1 General

4.1.1 Material Selection

Material selection for individual components, including all seal materials, should meet the requirements of API 17A concerning:

- production, injection fluids, and completion fluids for wetted areas;
- exposure to chemical injection and service fluids;
- environmental conditions.

4.1.2 Design Recommendations

Subsea modules can be used to provide flexibility to meet various production scenarios, for example “retrofit” installation of pumps, separators, and other modules. Any requirements for future expansion should be addressed during the design phase. Future expansion functionality should be documented along with any requirements for implementation.

The following functionality related to structures and modules should be addressed during the design phase:

- transportation, lifting, installation (inclusive of potential levelling), abandonment;
- flowline pull-in, connection and seal testing;
- well drilling, completion, workover and XT installation;
- precommissioning and commissioning;
- production/injection start-up and production/injection;
- injection of chemicals, such as emulsion, scale, wax and corrosion inhibitors;
- methanol or monoethylene glycol (MEG) injection for hydrate control;
- thermal performance;
- annulus bleed operations;
- well testing;
- barrier testing;
- planned and emergency shut downs of wells and manifolds;
- pressurization and depressurization of piping system;
- slugging and flow-induced vibrations;
- vibration due to rotating equipment.
— pigging of flowlines, such as for gauge and cleaning operations;
— subsea inspections and interventions, inclusive of module replacement;
— diver or vehicle intervention access;
— sand/pig detection facilities inspection;
— well interventions;
— potential hook-up of retrofit-installed modules and components;
— seawater ingress during tie-in operations;
— corrosion protection;
— erosion protection;
— wall thickness measurement;
— fluid flow rate;
— pressure drop through piping system;
— fluid composition;
— configuration to minimize hydrate formation potential;
— fluid flow regimes (slugging).

4.1.3 Fluid Characteristics

Design of manifolds and piping systems should take into account the fluid characteristics. These fluids include produced hydrocarbons (liquids and gases), formation water, completion fluids, injected water and gases, barrier fluids, and injected chemicals.

The general design characteristics for produced fluids are typically supplied by the end user, and include:
— pour point;
— pressure;
— temperature;
— chemical composition;
— viscosity;
— gas/oil/water ratio (including any changes during the life of the field);
— sand/paraffin/hydrates;
— corrosivity.
4.1.4 Interfaces

The system interfaces should maintain integrity and functionality in the service conditions and take into account the following:

- internal and external pressure;
- expansion and contraction forces acting on the structure;
- zero external leakage;
- seawater ingress;
- tolerance loops for interface make-up;
- internal and external temperature variations;
- structure for protection against dropped objects and snag loading;
- impact from dropped objects;
- short- and long-term structure settlement;
- marine growth;
- corrosion and erosion;
- scaling on subsea mateable surfaces;
- potential blockage of piping system (e.g. hydrates);
- installation/retrieval loads;
- pull-in and connection loads;
- serviceability;
- protection from subsea vehicle impact loads;
- environmental loads (currents, waves, seismic);
- subsea controls connection systems;
- chemical injection requirements/locations.

Interface data sheets and outlined installation procedures for critical external interface areas should be provided. The data sheets, when implemented, should clearly describe design limitations, weights, and dimensions, as applicable. Areas that, as a minimum, should be covered are:

- interfaces towards the well system, including maximum conductor angle, hang-off weights, lengths of conductor, BOP envelopes, sequential requirements (sequence and number of wells that can be drilled before design load capacity is achieved), limitation on mud pressure/flow during drilling out the conductor, cement/grouting strength, well growth, wellhead design, etc.;
— interfaces towards marine contractor (equipment mass and size, lifting height, deck space, load capacity of tie-in points and structures, installation limitations, sea states, etc.);

— interfaces towards flowline jumpers, well jumpers, controls flying leads;

— interfaces with installation/retrieval systems and tooling.

### 4.1.5 Manifold Functionality

Manifold system design typically fulfills the following functions:

— commingles production fluids from production wells;

— distributes water/gas from/to multiple production, water, or gas injection wells;

— directs flow of fluids through manifold headers;

— contains one or more headers either using remotely or manually actuated valves;

— allows isolation of individual well slots from header;

— incorporates flowline connections between manifolds and appropriate flowlines and/or test lines;

— allows continuity for circulation of fluid and/or pigging of the flowline system;

— provides capability for future expansion;

— provides support to control system including control pods, sensors, flow meters, etc.

### 4.1.6 Manifold Performance and Configuration

The end user should define or approve the following performance and configuration requirements, including:

— maximum dimensions and target weight;

— pressure and temperature ratings (see 5.3.2);

— flow rates;

— equipment interfaces;

— process and instrumentation diagrams (P&IDs);

— materials requirements, including erosion and corrosion performance requirements;

— water depth;

— design life;

— geotechnical and geophysical data;

— metocean data;

— dropped-objects protection requirements;
— modes of operations (subsea hydrostatic testing, operation, bull heading, acid stimulation, etc.);
— subsea vehicle impact requirements;
— snag load for the geographic region;
— availability and reliability requirements;
— levels of redundancy of equipment within the manifold;
— overtrawling or fishing friendly requirements.

All equipment should:
— conform to the latest revision of the end user’s product requirements;
— be designed to the pressure and temperature ratings (see Appendix A for datasheet);
— be compatible (dimensions and mass) with construction site limitations as well as transportation vessels;
— be compatible (dimensions and mass) with the handling and installation capabilities of the installation vessel;
— be compatible with potential extreme conditions (hot or cold) during transportation, storage, and the installation site. Note: The transportation/storage/installation site may experience subzero weather, which could be more extreme than normal operating conditions.
— be functional and meet the requirements for the specified operating environment.

4.2 Standalone Structures

4.2.1 General

Standalone structures such as cluster manifolds, subsea distribution units, and electrical distribution units typically consist of a framework that supports other equipment, such as piping, pipeline pull-in and connection equipment, and protective framing. Standalone structures typically provide a foundation to sufficiently transfer all design loads into the seabed.

Examples of standalone structures are:
— production and injection cluster manifolds;
— subsea processing skids;
— subsea boosting stations;
— subsea controls and distribution structures.

Subsea structures may include the following components:
— subsea control module;
— subsea distribution unit;
— electrical distribution unit.
4.2.2 Structure Orientation

Standalone structures should provide an alignment capability to ensure proper orientation to physical interfaces, such as flying leads, connectors and foundations.

4.2.3 Subsea Guidance

Standalone structures should provide for a guidance system to support operations through the life of the installation. If guidelines are used, the standalone should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the standalone should provide sufficient space and passive guidance capability to successfully install key equipment items.

4.3 Pipeline Structures

Pipeline structures such as PLEM, PLETS, riser bases, in-line tees, and subsea isolation valve structures typically consist of a framework that supports other equipment, such as piping, pipeline pull-in and connection equipment, and protective framing, as well as installation equipment such as yokes and stab and hinge-over arrangements. The pipeline structures typically provide an end termination for a pipeline segment. The pipeline structures provide a foundation to sufficiently transfer design loads into the seabed.

Examples of pipeline structures are:

- PLEM;
- PLET;
- riser base;
- in-line tees;
- subsea isolation valve structures;
- towheads.

4.4 Template Systems

4.4.1 General

The framework of a template supports equipment such as manifolds, risers, drilling and completion equipment, pipeline pull-in and connection equipment, and protective framing. The template should provide a foundation to sufficiently transfer design loads into the seabed (see Figure 2).

The template design may be based on an integrated or modular system layout, as follows:

- integrated template, which concept may include bottom structure, manifold, and protection structure in one unit.
- modular template, which concept may consist of separately installable/replaceable modules and structures. If applicable, an additional requirement for moonpool installable size may be applied.

The following parameters will influence the selection of the template concept:

- field development strategy, including future expansion;
— reuse of exploration wells and predrilling of wells;
— field development schedule (including marine operations and rig schedule);
— field infrastructure;
— onshore facilities and infrastructure;
— installation vessel availability;
— reuse of tools.

4.4.2 Drilling and Completion Interface

If wells will be drilled through the template, the template should provide guidance for drilling, landing/latching capability for the first casing string, and sufficient space for running and landing a BOP stack. If subsea trees will be installed on the template, the template should provide proper mechanical positioning and alignment for the trees and sufficient clearance for running operations. The design will also need to accommodate removal of drilling cuttings.

4.4.3 Structure Orientation

The template should provide an alignment capability to ensure proper orientation to physical interfaces, such as wellhead/tree, tree/manifold and manifold/flowlines.
4.4.4 Subsea Guidance

The template should provide for a guidance system to support operations through the life of the installation. If guidelines are used, the template should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items.

5 Detail Design

5.1 General

5.1.1 Number of Wells

When wells are incorporated into the template or tied into a cluster manifold, the number of wells will vary depending on the site-specific application, and will greatly influence template size and manifold design. Spare well slots should be added for contingencies such as changes in reservoir depletion plan, dry holes, drilling problems, and other unforeseen production requirements, as agreed with the end user.

5.1.2 Well Slot Spacing

Well slot spacing at the mudline or on the cluster manifold may be governed by the field architecture and the type and size of drilling and production equipment used. The following will need to be addressed during the design phase:

- For a template solution, the functional requirements of the manifold, flowline, and wellhead connections and their running tools and adjacent BOP and production tree clearances will determine the minimum well slot spacing. Access should be provided for inspection and maintenance tools.

- For a cluster manifold solution, the jumper design and well jumper connection system will determine the minimum well slot spacing.

5.1.3 Intervention Functionality

Intervention is a key factor in system design, and the maintenance approach should be used in the design phase of a template or subsea structure system. Required maintenance should be minimized and limited to retrievable modules where possible. Specific guidance on intervention flushing and retrieval can be found in 11.2.1 and 11.2.2.

The following factors will influence intervention planning and functional requirements:

- diver-assisted or remote maintenance methods;

- inclusion of reaction posts/secure points for diver-assisted lift rigging;

- clear definition of which components will be retrievable;

- clear access space for divers, subsea vehicles, or other intervention equipment;

- clear markings to allow distinguishing similar components;

- height above seabed for adequate visibility;

- system safety with components removed;

- fault detection to identify failed components.
5.1.4 Barrier Philosophy

Refer to API 17A for additional information on barrier philosophy. Prior to any subsea operations which involve use or removal of an environmental barrier, a risk/safety assessment should be performed to ensure risks are identified and mitigated.

Permanent isolation requirements against external leakage for pressurized systems should be provided by double, pressure-containing barriers in all external connection points. The primary barrier intended for long-term service should be metal-to-metal sealing type. Individual barrier integrity should be confirmed by leak testing, and the final dual barrier integrity should be verified.

For temporary, time-limited operations, it can be acceptable to use only one metal-to-metal sealing isolation valve for isolating pressurized piping towards the environment. The primary barrier valve should be verified to ensure it is holding pressure prior to releasing the outboard barrier. An overall safety assessment should be performed for the activity prior to the start of operations.

NOTE If the primary barrier valve cannot be verified, depressurization of the pressurized piping to prevent flow to the environment may be an acceptable alternative to verifying the primary barrier valve.

The closure element of a valve (gate, ball) should not be permanently exposed to the environment. Where possible, an inhibited volume should be provided on the environmental side of the isolation valve in order to avoid seawater-imposed corrosion of and fouling on the valve.

The volume between barrier valves should be maintained with stagnant fluid to minimize issues with corrosion and hydrates (i.e. close both valves with fluid trapped in the volume).

Recommended barrier philosophies for subsea structures to be used in conjunction with a risk analysis:

a) unused end connections or end connections that are unpopulated prior to commissioning of the piping module:

   two pressure barriers: one primary metal-to-metal sealing isolation valve and one secondary sealing pressure plug/cap or two metal-to-metal isolation valves;

b) hook-up of an XT or flowline jumper after commissioning of the piping module in combination with a nonpressurized piping module:

   one metal-to-metal pressure barrier;

c) for diver-mated connections:

   two pressure barriers with a block-and-bleed function.

NOTE Generally, high-pressure caps are required to complete the testing of the piping system prior to installation of a subsea structure. The number and type of high-pressure caps required for the testing program will need to be included in the equipment scope of supply.

5.1.5 Safety

It is important that safety risks are addressed for all phases and uses of the manifold system, including: fabrication, testing, transportation, installation, operation, and recovery (see the section on design criteria safety and hazards of API 17A).
5.1.6 Corrosion Protection Design

External corrosion control shall be provided by appropriate materials selection, coating systems, and cathodic protection.

A corrosion control program is an ongoing activity that consists of testing, monitoring, and replacement of spent equipment in which appropriate materials selection, coating systems, and cathodic protection shall be used to provide external corrosion control.

The potential for internal corrosion and cathodic protection current drain to structural compartments that are flooded (to prevent hydrostatic collapse) should be addressed.

NOTE The implementation of a corrosion control program is beyond the scope of this document. Guidance for external corrosion protection of all components can be found in API 17D. Cathodic protection design guidelines are contained in DNV-RP-B401 and NACE RP 0176.

5.2 Loads

5.2.1 External Loads

5.2.1.1 Design Loads

All applicable loads that can affect the subsea production system during all phases, such as fabrication (i.e. use of come-alongs), storing, testing, transportation, installation, drilling/completion, operation, and removal, should be defined and form the basis for the design. Accidental loads are project-specific and should be verified by a special risk analysis for the actual application. Accidental loads can include dropped objects, snag loads (fishing gear, piles), and abnormal environmental loads (earthquake), etc. Additional load cases or details can be added to the information in the data sheet in Annex A.

Typical design loads include:

— design pressure and temperature;
— lifting and handling loads (including recovery);
— jumper-induced loads;
— pipeline expansion;
— fatigue loads due to operational cycles;
— vortex-induced vibration (VIV);
— flow-induced vibration (FIV);
— snag loading;
— environmental loads;
— loads from a subsea vehicle impact;
— thermally-induced loads;
— load during installation of equipment (e.g. subsea control module (SCM), choke modules, pump modules);
— accidental loads.
5.2.1.2 Environmental Loads

Environmental loads that can affect subsea structures during fabrication, storing, testing, transportation, installation, drilling/completion, operation, and removal should be defined and form the basis for the design. The data sheet in Annex A may be used to define applicable loads. Environmental loads should be developed consulting the metrological parameters at field location (e.g. wind and sea bed current).

5.2.1.3 Accidental Loading

Design of subsea structures for protection against trawl loads and dropped objects should be based on actual loadings from the findings of the regional fishing study where the structures are located. In the absence of such studies, loadings should be based on the requirements in API 17A and/or NORSOK U-001.

However, since fishing gear, in general, has changed in design and increased in size/mass during recent years, increased trawl-loads protection can be necessary for certain fields/projects.

Each project should complete a field-specific examination in the early phase in order to establish the requirements for the use of increased trawl-loads protection. Both historical data and expectations for the future shall be assessed.

The following data shall be established for each project:

a) historical trawling data for the field/region (tracking data):
   1) category type of trawl equipment,
   2) frequency;

b) expectations for the future;

c) trawl-loads parameters for the subsea structures on the field:
   1) trawl net friction, expressed as a force,
   2) trawl equipment pull-over, expressed as a force,
   3) trawl equipment impact, expressed as energy.

The design should avoid small, closed corners on the protection structures to reduce the risk of snagging. Overtrawlability tests should be performed for new structure designs as required by the end user.

For equipment operating at depths deeper than 750 m, bottom trawling is less common. For locations where it can be documented that no bottom trawling occurs and is not likely to occur within the design life of the installations, an overtrawlable protective structure may not be required.

5.2.2 Thermal Effects

Equipment designs should be capable of functioning throughout the temperature range for which the product is rated. The end user is responsible for specifying or approving this temperature requirement.

Thermal effects include allowance for:

— thermal expansion of conductor/wellhead housings;
— thermal expansion of pipelines/flowlines;
— thermal expansion of trapped fluids;
— environmental effects during fabrication;
— testing of equipment during transportation, storage, and installation.

5.2.3 Drilling Loads on Templates

If a template structure is selected, drilling loads will be transferred into the structure. The structure should be able to accommodate applicable loads addressed in API 17A and NORSOK U-001, including the following;

— drilling loads;
— fatigue loads;
— thermal expansion of casing;
— combined drilling and thermal expansion loads, including any foundation settlement load effects;
— tie-in loads and flowline expansion loads;
— impact loads;
— soil conditions and axial stiffness of well system;
— structural design and stiffness of bottom frame against vertical deflection;
— structure/well interface design and flexibility tolerances (if any).

If a template solution is chosen in which the drilling loads are not transferred into the template/manifold, the drilling/well loads described above may be neglected.

5.3 Piping Systems

5.3.1 General Requirements

Piping systems for standalone and pipeline structures may provide some or all of the following functional requirements:

— have sufficient piping, valves, and flow controls to safely gather produced fluids and/or distribute injected fluids such as gas, water, or chemicals;
— provide for the connection of flowlines;

NOTE The manifold typically provides sufficient flexibility to make and break flowline connections.

— provide for the connection of flowline components such as pump modules, flow meters, and chokes;
— be designed to account for hydrostatic loads due to external pressure;
— be designed for the full temperature range including effects from Joule-Thomson cooling;
— have appropriate valve and line-bore dimensions to allow pigging of flowlines and appropriate manifold headers;

— provide for the connection to the tree/well jumper,

— provide for testing of individual wells;

— provide for mounting and protecting equipment needed to control and monitor production/injection operations. This may include a distribution system for hydraulic and/or electrical supplies for the control system.

Recommendations for the piping system include the following:

— The piping system should include a length of straight pipe downstream of the choke valve and MPFM, in order to prevent any extensive erosion damage on the bend, connector sealing/contact surfaces, sensors, or similar locations. The minimum length of straight pipe should be seven times the inside piping diameter unless otherwise specified by the manufacturer.

— The size (diameter, wall thickness, etc.) of production piping for individual lines and/or combined streams should be determined from anticipated well flow rates and well pressures.

— The size (diameter, wall thickness, etc.) of injection piping for individual lines and/or combined streams should be determined from anticipated injection flow rates and pressures.

— Fluid velocities should be lowered where possible when sizing pipes in order to reduce pressure drops and control flow-induced erosion.

— An internal erosion and corrosion allowance should be established when calculating the required wall thickness.

— Additional wall thickness allowance should be established when the design includes PWHT, or cold or induction bends.

— The design should allow access for NDT activities and for the application of piping insulation during fabrication.

— Placement of sensors should be done to optimize their performance. For example, temperature sensors should be placed downstream of branch connections and chemical injection points to avoid influencing the bulk fluid temperature measurement.

— The potential for flow-induced vibrations should be minimized by using the largest pipe diameter possible to minimize flow velocities and adequate pipe supports to increase the natural frequency of free spans.

— Piping design on a subsea structure should be optimized in order to minimize the potential for vortex-induced vibrations, in combination with ensuring sufficient flexibility.

— Piping design should include vibration analysis when rotating equipment such as a subsea pump is used.

— Piping systems shall not be relied upon to resist structural loading or to strengthen the structural framing system.

— Piping in production systems should be optimized to enhance the thermal performance of the system during a shutdown, in accordance with flow assurance requirements (e.g. to maintain minimum temperature according to the hydrate prevention philosophy, or wax or gel appearance/formation).
5.3.2 Applicable Piping Codes

Codes used in the design of piping systems for subsea use are: ASME B31.8, ASME B31.4, ASME B31.3, ASME VIII, DNV-OS-F101, DNV-RP-F112 (duplex material), or API 1111. In addition to the piping codes, API 17TR12 addresses design constraints related to external ambient seawater pressure on subsea equipment, and API 17TR8 provides design guidelines for high pressure/high temperature subsea equipment. One or more of these codes can be used for a single manifold design. If the applied code has a subsea section, it should be applied. All applications from fabrication to operation should be incorporated into the design.

Design factors in API 17D/ASME VIII or ASME B31.8 (Compressor Station Piping, Table 841,114B) can be applied in lieu of standard design factors in the pipeline codes.

Any local regulatory requirements should be met.

5.3.3 Pigging

When pigging with gauge plates for inner diameter (ID) verification of piggable piping, the recommended acceptance criterion is 95 % of nominal ID, i.e. the diameter of the testing gauge plate is 95 % of nominal ID. All piggable piping should include a minimum bend radius of 3D nominal diameter. The piping design should account for variations in ID, fitting spacing, and special branch connections.

Pig excluder devices (e.g., barred tees) should be used for large branch connections where the branch ID is greater than or equal to half the run ID.

NOTE Additional guidance on the design of pig excluders can be found in DNV-ST-F101.

5.3.4 Erosion

Critical flow velocity introducing erosion in the piping can be calculated as given in ANSI/API RP 14E or DNVGL-RP-O501. These calculations can be used to determine critical production rates and/or to calculate the required erosion allowance for the manifold piping. The contractor should identify critical areas in the piping exposed to erosion. Increased bend radius and fitting design can be used to mitigate erosion effects. Materials with higher PREN can be selected to mitigate erosion effects. Designated inspection areas may be added to the piping system to allow for subsea inspection measurements of the production piping wall thickness.

5.3.5 Flow Assurance

The manifold should be designed to avoid/minimize low points, dead ends, and locations of possible water or solids accumulation. For example, a tilted manifold header that drains header fluids out from the manifold may be used as a measure to prevent hydrate formation in the manifold. Special attention should be given to gas-producing manifolds regarding distribution of injected chemicals, related to “uphill/downhill” and “dead legs” in the as-built piping system.

NOTE Additional general flow assurance guidance can be found in API 17A.

5.3.6 Chemical Injection

The layout and arrangement of the chemical injection piping and valves in the manifold should be evaluated with respect to reliability, failure modes and consequences, offshore system testing, component/module replacement and testing, troubleshooting, etc. Location of injection points in the manifold header should be specified or approved by the end user.
5.4 Structural Design

5.4.1 General

Subsea structures shall be designed to relevant standards such as API RP 2A, ISO 19900, or ISO 19902. Structural components (i.e. pad eyes, lift columns, braces/supports, foundation elements, etc.) and welds joining them shall be classified (i.e. design class or material class) based upon the consequence of failure, degree of redundancy, joint complexity, levels of stress, and fatigue. The classification shall be used to determine:

— material selection (steel category);
— joint design;
— welding requirements;
— type and extent of inspection (inspection category).

The two approaches from ISO 19902 provide detailed guidance for design classification and materials selection of jacket structures and can be correlated to manifold structures. Designers should be careful to select design codes, welding codes and material selections that have been developed together, such as API 2A, AWS D1.1 and ASTM A-36. MC codes (AWS D1.1) and DC codes (NORSOK N-001) should not be used together.

NOTE ISO 19902:2007, Annex C, describes the material class (MC) approach and Annex D describes the design class (DC) approach. With respect to selection of material standards and grades, the MC approach specifies grades to ASTM and API standards and the DC approach to the EN standards. Welding and inspection requirements are specified in ISO 19902:2007, Annexes E and F.

Subsea structures typically avoid hydrostatic collapse of hollow members by passive filling (“flooding”) during installation. Special attention is required during design and fabrication to ensure that all enclosed volumes at risk of hydrostatic collapse are identified and provided with appropriately sized vent and flooding holes where necessary.

5.4.2 Rotating Equipment Support Structure

The structure which is directly connected to rotating equipment should meet the requirements listed in 5.4. The structure should be designed to transfer all design loads from the rotating equipment to the foundation system.

A natural frequencies analysis, together with a response analysis, should be conducted on the rotating equipment structure and be documented in a report. As an alternative to a natural frequency analysis, the requirements of this section can be satisfied by testing.

The analysis should, as a minimum, include:

— a description of the analyzed model, the methods used, and the assumptions made during the analysis;
— the calculated natural frequencies from 0 Hz up to minimum 150 % of maximum continuous speed and plots showing their corresponding mode shapes;
— The response analysis in both displacement (mm) and vibration (mm/s) caused by a unit load (for instance, 1000 N) on each piece of rotating equipment and motor-bearing locations;
— The analysis should be run continuously from 0 Hz up to minimum 150 % of maximum continuous speed with a delta frequency of 1 Hz, unless otherwise agreed;
— For vertical pump units, the pump module support structure together with the pump should have a first (fundamental) natural frequency 25% below the lowest operational speed of the pump unit.

To avoid resonance, local structure should be designed such that the natural frequencies of the support structure do not lie between 0.65 times and 1.5 times the operating frequency of the equipment supported.

5.4.3 Foundation Support Structure

The structure should transfer all design loads from interfacing systems and equipment to the foundation system.

Loads from the well system induced on the guide frame/bottom frame depend on the following:

— soil conditions;
— axial stiffness of the well system for template applications;
— structural design and stiffness of bottom frame against vertical deflection;
— structural/foundation;
— structure/well interface design and flexibility tolerances (if any);
— casing thermal expansion.

The structure should ensure sufficient alignment capability for proper physical interfaces between subsystems such as wellhead/production guide base, subsea tree/manifold and piping system, manifold/flowline termination and installation aids, protective structure (if relevant), and other relevant interfaces.

The subsea structure does not have to be fixed/locked to its corresponding foundation unless it is being installed as one unit or it is deemed necessary by the equipment designer to properly transfer loading to the foundation.

The subsea structures may be fixed/locked to the wellhead system, or they may be separated with no direct fixed connection to the wellhead. Hence, corresponding piping is connected using built-in flexibility in the wellhead modules and/or manifold module. Well-supporting structures shall typically provide guiding/landing/latch capability for the conductor housing and sufficient space for running and landing of a BOP stack on the corresponding wellhead and adjacent to a neighboring subsea tree.

The structure should allow onshore assembly and testing of equipment supported by the structure. The structure should be self-supporting such that a testing stand is not required for standard testing activities and conditions.

Filling of hollow tubular volumes should be passive. If passive methods are not available, filling should be conduction from deck level using a quick connector.

**NOTE** Generally flooding holes are located at the high point and low point of a hollow structure. This allows air to escape through the high point hole during flooding and conversely, water to drain from the low point in the event of a recovery.

5.4.4 Protection Structure

The following main design principles should be used for the protection structure design:

— The protection structure size should take into account all fabrication, installation, and operational tolerances (e.g. well expansion) of the protection structure and production equipment.

— The height of the protection structure should be minimized in order to reduce the lifting height.
— The height should be dimensioned such that deformation of the protection roof caused by dropped-object impact does not result in physical contact of the roof with the production equipment (e.g., XT, manifold). This is not applicable if the production equipment has a protection roof capable of withstanding the dropped-object impact load requirements.

— Subsea vehicle access should be provided for inspection and manipulative tasks, such as valve operations on the manifold and XT. The need for opening the hatches/covers should be minimized or eliminated where possible.

— The arrangement of the roof hatches should not prevent WROV access to the manifold, to other areas identified for intervention tasks, or to adjacent XTs while performing rig operations (drilling and completion) on a well slot. It should be noted that access with WROV to the manifold and XT can require opening of the roof hatches.

— Roof hatches should be arranged to allow for simultaneous operations (for example, during intervention on one well slot, the neighboring well slot should be protected).

— Roof hatches should be made separately retrievable. Any interface permanently left at the seabed should be designed to maintain its functionality upon roof hatch damage and should allow for retrieval and reinstallation of a roof hatch.

— The protective structure should facilitate the tie-in of any applicable flowline connection system (flowline tie-in should be effective regardless of selected tie-in system).

— Intervention operations that require the removal of the protection structure should be limited to nonroutine, low-probability activities.

— The roof hatches may be operable by direct and/or indirect pull, using guide wires, both for closing and opening. Pulling requirements should be defined by end user.

— Protective structures may mount to the protected subsea structure or require a separate foundation. Locking mechanisms may be required to prevent trawling activities from dislodging protective structures from their foundation.

— Any transport/installation tie-down devices used on the roof hatches should be designed to adequately take all loads and be easily removable subsea intervention.

— Special attention should be paid to the design of the wire guides on protective covers. It should be possible to easily thread and unthread the wire via subsea intervention when the cover is either fully open or fully closed and possible to check for potential jamming or locking of the wire at any end position. The design should allow for at least 30° out-of-verticality of the lifting wire in any direction and at any cover position without allowing the wire to slip out of the wire guide system.

### 5.5 Foundation Design

#### 5.5.1 Foundation Configuration Selection

The foundation design should be selected based on site-specific soil conditions. Foundation configurations that can be used include mudmats, skirts, driven piles, suction piles, conductors, or a combination of these. It is important to evaluate subsurface obstacles such as boulders, as well as drilling aspects such as mud pressure, mudflow, washout, drill cuttings, and overflow from wellhead grout as part of the selection criteria.

The following are design inputs that influences the design of the foundation and leveling system (if required):

— induced loading transferred from structure;
— time between installation and application of loading;

— seabed slope, installation tolerances, and effects from possible scouring;

— suction loads due to repositioning or leveling;

— soil plug stability during installation of suction piles;

— use of a foundation system for well-supporting structures, based on support/anchoring on the well conductor housings;

— arrangements (in foundation and skirt systems) for air escape during splash-zone transfer, and water escape during seabed penetration, taking into account lift stability and washout of soil;

— design of structures with skirt foundation for self-penetration;

— design of foundations to resist overturning;

— skirt-system functionality for suction and pumping for final penetration, leveling and breaking out prior to removal; the suction and pump systems. This functionality should be consistent with the selected subsea intervention strategy;

— settlement of the structures (installation and lifetime);

— impact of heat from produced hydrocarbons, particularly if gas hydrates are present.

5.5.2 General Design

Foundation design should comply with the requirements and principles listed in API RP 2SK and API RP 2 GEO. Specific guidance for foundation design for subsea structures is given in the following section of this document.

The foundation design should be able to withstand loads from tie-in of flowlines, spool-pieces, pipelines, umbilicals, and other flowlines. For templates, all such loads should be accommodated prior to drilling and completion. A system for measuring well growth and settlement should be incorporated based on project requirements.

Erosion/washout due to drilling should be accounted for in the design. If the distance between foundation and the well is short, and soil conditions are sensitive to erosion/washout, 25 % of the circumference of one foundation should be assumed eroded when drilling through the same conductor (i.e. 25 % of outer skirt area).

Contingency methods should be established for situations where the foundation fails to penetrate the seabed.

Contingency solutions include:

— adding weight to assist penetration;

— filling grouting into the skirt compartment—a 2 in. (50 mm) injection point and a 2 in. (50 mm) vent is usually required on top of the skirt foundation;

— relocate the structure within a predefined target area;

— use of pin piles through mud mat foundations to provide extra stability in cases of under penetration or high angle seabed slope.
5.5.3 Suction Piles

A typical analysis for suction piles includes the penetration resistance, the underpressure required to allow embedment, and the critical pressure at which the soil plug fails. Suction pile geotechnical analysis should conform to API 2GEO and API 2SK.

Depth markings should be provided on the suction pile that can be used to verify embedment length via subsea inspection. Increments used near the target depth should align with the agreed embedment depth tolerance.

NOTE 1 Other than markings, the penetrating length of the pile can be left uncoated to provide a higher friction factor for the soil/steel interface.

Suction piles should have an independent cathodic protection system.

Suction piles should be designed to withstand all foreseeable lift configurations during transfer, upending, and deployment. Appropriate lift points shall be provided for all lift scenarios.

Penetration resistance can be calculated as the sum of the side shear and end bearing on the side wall and any other protuberances. The critical underpressure is the underpressure that causes a general reverse bearing failure at the pile tip and large soil heave within the pile. The recommended allowable underpressure is defined as the maximum underpressure that should be applied to the foundation divided by a safety factor. A typical value for the safety factor is 1.5. The allowable underpressure and soil heave are potential limitations on pile installation. Suction piles should include vent hatches (with documented pressure/suction capacity) for ease of installation.

Side friction can increase with the passage of time due to soil thixotropic effects and pore pressure redistribution at the pile interface. This phenomenon is often referred to as “set-up” and can be defined as the time between when the foundation is installed and when external loading is applied. Increasing the set-up time increases the foundation loading capabilities.

NOTE 2 A suction pile is installed by first lowering it into the soil to self-penetration depth (i.e. penetration due to submerged pile weight). The remainder of the required penetration is achieved by pumping out the water trapped inside the suction pile.

A vent system shall be provided to allow water to egress the descending suction pile during installation. The vent system shall be sized to:

— prevent soil damage when the pile approaches the seabed;
— maintain soil plug integrity;
— allow for a reasonable self-weight penetration rate.

Suction piles are not appropriate for applications where there is a gravel seabed, as ground-water flow limits suction. Parameters for suction pile design include:

a) design inputs:
— closed versus open top;
— post installation, which may affect long-term settlement;
— inclusion of internal ring stiffeners or bracing which affect skin friction;
— installation tolerances (e.g. tilt, orientation);
— distance between installation locations to avoid mobilizing disturbed soil;
— integrated transportation/shipping rails.

b) fabrication inputs:
— pile diameter;
— wall thickness;
— pile length;
— out-of-roundness;
— circularity;
— straightness.

A dimensional inspection and control plan should be developed to describe the method for maintaining required dimensional tolerances through all fabrication and transportation activities.

5.5.4 Driven Piles

Driven pile foundations provide a large vertical load capacity. Some of the guidance provided in 5.5.2.2 for suction piles may be applicable for driven piles. The calculation of driven pile capacities, as developed for fixed offshore structures, is well documented in API 2GEO. The recommended criteria in API RP 2GEO should be applied for the design of driven piles.

The design of driven piles should allow for typical installation tolerances that can affect the calculated soil resistance and pile structure. Pile verticality affects components of vertical and horizontal loads. Underdrive affects the axial pile capacity and can induce higher bending stresses in the pile.

5.5.5 Foundation Structures with Skirt

Structures and foundations can be designed with a skirt to improve foundation performance. When using a skirted design, the foundation should account for penetration resistance and horizontal/vertical load component capacities and ensure self-righting behavior during installation.

For suction skirt foundations, the skirts may be unpainted in order to achieve maximum friction between the skirts and the soil. The installed weight of the structure should be accommodated solely by skirt friction (i.e. without any load resting on the skirt roofs mudmat). A filter mattress may be installed underneath the mudmat in each suction pile to facilitate distribution of pressure to the entire mudmat area.

5.5.6 Non-skirted Foundation Structures

A non-skirted foundation or structure should provide enough surface area to support the subsea structure, interfacing systems, and design loads. For non-skirted foundations and structures, adequate measures should be adopted to mitigate the risk of snagging in the in-place condition.

Settling and suction forces during pull-out can be greater for non-skirted foundations and structures than for skirted foundations and structures, and should be accounted for in the design.
5.5.7 Leveling

Generally, subsea systems require that subsea structures (templates, manifolds, etc.) be level within a tolerance of their final position for proper interface and mating of the components and subsystems. However, the requirement for leveling of subsea structures should be determined on a case-by-case basis. If the installation tolerances of the foundation are within the verticality limits of the manifold’s retrievable sub-systems (such as connections, controls modules, etc), then leveling is not required. If the seabed inclination is outside the range of the allowable operating inclination of the structure, a means of compensating for the inclination should be incorporated. A means of level indication can be included on the structure to determine the installed inclination.

If leveling is required, then the recommendations of in this section should be followed when applicable.

Depending on the foundation method, leveling of the structure may be achieved by use of jacks or by pumping material in/out of the skirt compartments. A combined solution of skirts, mudmats, and jacks may be used.

The leveling system should be able to adjust the inclination within a tolerance specified by the contractor, accompanied with documented feasibility of all relevant operations. Typical leveling designs allow for the template structure to be leveled within 0.5°. For other structures such as cluster manifolds and PLEM, the typical final inclination should be less than 1.0°. It is recommended that the foundation be designed for a seabed slope of at least 3° or as specified for each project. Facilities to monitor inclination and offsets on the structure should be available on the structure or the ROV panel with sufficient resolution/accuracy.

Typical solutions include:

- adjusting the inclination of the mudmat relative to the structure;
- surveying and leveling the landing area of the mudmat;
- one- and two-way slips between piles and pile guides;
- jacking systems at the template corners;
- the active-suction method.

If a hydraulic jacking system is selected, the design should include a method to mechanically lock the structure relative to the mudmat after levelling.

For the suction skirt option, it is recommended that one ROV-controlled leveling panel be installed on the subsea structure or the separate protection structure, and each skirt should be able to operate individually. The panel should be connected by piping to each skirt compartment.

A single independent valve should be included on the leveling piping routed to each skirt. Pressure gauges may be included on the ROV panel, should be of a readable size, and should be located above the associated valve. Each compartment should be monitored, i.e. with one ROV-readable pressure gauge connected to each compartment’s piping.

Any requirement for leveling of the structure after the first conductor hang-off should be incorporated into the functionality of the template design.

5.5.8 Grouting System

A stab/receptacle system for contingency grouting of suction piles may be provided. It is recommended that the receptacle and stab (a minimum of two stabs) be provided by the contractor supplying the structure. The receptacle and stab should be designed for the applicable loads from the grouting riser/hose to the connector.
5.6 Pad Eyes and Other Lifting Devices

Pad eyes shall be designed and marked as given in API 17A, or design in accordance with DNV 2-7.1. Alternatively, an engineered lift plan can be implemented and used for the design of pad eyes if agreed by the end user and installation contractor. If the lifting devices are either pressure-containing or pressure-controlling, and are designed to be pressurized during lifting operations, then the load capacity should include stresses induced by internal rated working pressure.

Alternative testing of pad eyes can be proposed where normal testing is impractical (see 6.1.2 for material requirements).

5.7 Subsea Marking

Subsea marking should follow the principles and guidelines listed in API 17H. Load capacity should be marked on all pad eyes and other lifting devices.

A commonality of marking abbreviations among subsea facilities and surface-operating equipment is essential. To minimize confusion and enhance safety where the control units are designed for multiple applications, it is recommended that functions be identified on both the subsea packages and their control units, using common abbreviations listed in API 17H. If the valve arrangements are unique, the documentation should clearly define the abbreviations used in the marking of equipment.

The color and marking system should fulfill the following functions:

- follow the top coat colors recommendations in API 17H;
- identify the structure and orientation;
- identify the equipment mounted on the structure and intervention interfaces;
- identify the position of any given part of the structure relative to the complete structure;
- identify the operational status of the equipment, e.g. connector lock/unlock and valve open/close.
- enable positive verification of the end stop and/or locked position for retrievable components, such as guideposts to lockdown clamps, etc.

5.8 Components

Subsea manifolds comprise a number of components, such as valves, controls, and connectors. All components of the manifold system are covered in the scope of other specifications, codes, and RPs. These components should be designed, built, tested, and qualified according to the applicable specifications, codes, and RPs. Table 1 provides examples of applicable industry standards that can be used.
Table 1—Industry Standards for Manifold Components

<table>
<thead>
<tr>
<th>Component</th>
<th>Industry Specification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production/injection valves</td>
<td>API 6A; API 17D; API 6DSS</td>
</tr>
<tr>
<td>Chokes</td>
<td>API 6A; API 17D</td>
</tr>
<tr>
<td>Control system components</td>
<td>API 17F</td>
</tr>
<tr>
<td>End connectors</td>
<td>API 17R</td>
</tr>
<tr>
<td>Flanges</td>
<td>API 6A; API 17D</td>
</tr>
<tr>
<td>HIPPS</td>
<td>API 17O</td>
</tr>
<tr>
<td>MPFM</td>
<td>API 17S</td>
</tr>
<tr>
<td>Engineered Fittings</td>
<td>ASME B16.9</td>
</tr>
<tr>
<td>Pressure Vessels</td>
<td>ASME VIII, <em>Boiler and Pressure Vessel Code (BPVC), Section VIII, Rules for Construction of Pressure Vessels, Div. 1</em></td>
</tr>
</tbody>
</table>

6 Materials and Welding

6.1 Materials

6.1.1 General

Material requirements for subsea structure components listed in section 5.8 should follow the applicable specifications, codes and RPs.

The material and welding requirements for integrating components should meet the additional requirements from this RP.

The pressure-containing parts of the manifold structure should be formed from carbon, low-alloy, stainless steel, or nickel alloy as listed in 6.1.3, 6.1.4, and 6.1.5.

A detailed material specification for each type of product should be established. The material specification shall clearly identify all manufacturing and testing requirements.

6.1.2 Structural Material

6.1.2.1 General

Structural materials shall meet the requirements of API 2A-WSD or ISO 19902. Pad eyes and lifting points should conform to the requirements of 5.6 for design.

6.1.2.2 Primary Structural Members

Primary structural members are in the direct load path and transfer primary stress under major design loads. Generally, these are columns, beams, and bracing members directly attached to columns. The following minimum material properties are recommended for primary structural members including plates and pad eyes:

- through thickness tensile testing, “Z” direction, as given in ASTM A770/A770M or EN 10164, 30 % minimum reduction of area Z-directional properties;
- sulfur controlled to a maximum of 0.006 % with inclusion shape control;
ultrasonic testing per SA578, level B or EN 10160, class S1;

Charpy requirements: temperature from the CVN test (TCVN) 29 ft/lb average 20 ft/lb minimum at –4 °F (40 Nm average/28 Nm minimum at –20 °C) supplements.

### 6.1.2.3 Structural Materials Toughness Requirement

Steel used for the main load-bearing structure shall be impact tested as required by the design code. Steel for pad eyes should conform to the applicable standard for lifting operations.

### 6.1.3 Piping Material

#### 6.1.3.1 General

Piping material shall be manufactured either by a seamless process to form a tubular product without a welded seam or by a longitudinal arc-welded process with added filler material.

Carbon and low-alloy steel pipe shall conform to an appropriate reference standard suitable for the application, for example those listed in Table 2.

<table>
<thead>
<tr>
<th>Standard</th>
<th>Manufacturing Process</th>
<th>Standard</th>
<th>Manufacturing Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>API 5L PSL 2</td>
<td>Seamless and welded pipe</td>
<td>EN 10216-3</td>
<td>Seamless pipe</td>
</tr>
<tr>
<td>ASTM A333/A333M</td>
<td>Seamless and welded pipe</td>
<td>EN 10217-3</td>
<td>Welded pipe</td>
</tr>
<tr>
<td>ASTM A988/A988M</td>
<td>Seamless and welded pipe, Hot Isostatic Pressed (HIP)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

For welded pipes, the PQR/WPQR should be qualified in accordance with ASME BPVC Section IX, ISO 15614-1 or equivalent and conform to the base material requirements.

Stainless steel and nickel-based alloy pipe shall conform to an appropriate reference standard suitable for the application, for example those listed in Table 3.

<table>
<thead>
<tr>
<th>Standard</th>
<th>Manufacturing Process</th>
<th>Standard</th>
<th>Manufacturing Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A312/A312M</td>
<td>Seamless pipe</td>
<td>EN 10216-5</td>
<td>Seamless pipe</td>
</tr>
<tr>
<td>ASTM A358/A358M</td>
<td>Welded pipe</td>
<td>EN 10217-7</td>
<td>Welded pipe</td>
</tr>
<tr>
<td>ASTM A790/A790M</td>
<td>Seamless pipe</td>
<td>ASTM B705</td>
<td>Seamless and welded pipe</td>
</tr>
<tr>
<td>ASTM A928/A928M</td>
<td>Welded pipe</td>
<td>API SPEC 5LC</td>
<td>Seamless and welded pipe</td>
</tr>
<tr>
<td>ASTM A872</td>
<td>Centrifugally Cast Ferritic/ Austenitic Stainless Steel Pipe</td>
<td>ASTM A995</td>
<td>Castings, Austenitic-Ferritic (Duplex) Stainless Steel</td>
</tr>
</tbody>
</table>

For clad pipe, the carbon steel pipe shall conform to an appropriate reference standard suitable for the purpose of the application, for example those listed in Table 2.
6.1.3.2 Nondestructive Testing of Seamless Pipe and Fittings

All seamless pipes and fittings should be inspected for surface defects. The entire outside surface should be inspected by an appropriate method defined by the applicable product standard. The welding ends should be inspected by magnetic particle or dye penetrant method. Acceptance criteria shall be in accordance with the applicable reference standard.

Seamless pipes shall be tested by the ultrasonic method in accordance with API 5L PSL 2, with notch calibration to type N5. Defects should be removed according to dispositions given in the reference standards, but weld repair is not permitted.

6.1.3.3 Nondestructive Testing of Welded Pipe

Longitudinal welds of welded pipes and fittings should be 100 % volumetrically inspected in the final heat-treated condition by radiography or ultrasonic method. Weld prep ends should be surface-inspected by magnetic particle or dye penetrant method. Acceptance criteria should be as given in the applicable reference standard.

6.1.4 Fitting Material

6.1.4.1 General

The fittings shall be manufactured by:

— a seamless process, hot working steel to form a tubular product without a welded seam; or

— a longitudinal arc-welded process with added filler material; or

— forging.

Carbon and low-alloy steel fittings shall conform to an appropriate reference standard suitable for the purpose of the application, for example those listed in Table 4.

<table>
<thead>
<tr>
<th>Standard</th>
<th>Manufacturing Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A420/A420M</td>
<td>Seamless and welded fittings</td>
</tr>
<tr>
<td>ASTM A860/A860M</td>
<td>Seamless and welded fittings</td>
</tr>
<tr>
<td>ASTM A182/A182M</td>
<td>Forged fittings</td>
</tr>
</tbody>
</table>

For welded fittings the PQR/WPQR should be qualified in accordance with ASME BPVC Section IX, ISO 15614-1 or equivalent and conform to the base material requirements.

Stainless steel and nickel-based alloy fittings shall conform to an appropriate reference standard suitable for the application, for example those listed in Table 5.
Table 5—Reference Standards for Seamless, Forged and Welded Manifold Fittings in Stainless Steel Alloy

<table>
<thead>
<tr>
<th>Standard</th>
<th>Manufacturing Process</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A403/A403M</td>
<td>Seamless and welded fittings</td>
</tr>
<tr>
<td>ASTM A815/A815M</td>
<td>Seamless and welded fittings</td>
</tr>
<tr>
<td>ASTM B366</td>
<td>Seamless and welded fittings</td>
</tr>
<tr>
<td>ASTM A182/A182M</td>
<td>Forged fittings</td>
</tr>
</tbody>
</table>

6.1.4.2 Bending and Forming Operations

6.1.4.2.1 General

The thickness after bending or forming should be not less than that required by the applicable design requirements.

The forming and post-forming heat treatments of thermo-mechanical steels shall be determined along with the recommendations of the steelmakers.

When bending clad pipe, a full thermal treatment, including the clad weld to final product, should be established and qualified.

6.1.4.2.2 Cold Forming

Components in austenitic stainless steels and nickel alloys may be cold formed provided the material properties after any cold forming are verified to be within the usage limitations stated in ISO 13628 1:2005/Amd 1:2010. Cold bending or deformation of any other material should not be performed unless agreed with the end user.

Any increase in mechanical strength of the material due to cold deformation shall not be used to increase the allowable design stress.

The hardness of any cold-formed metallic material shall conform to the maximum hardness limits in API 17A and to ISO 15156 (all parts) for items exposed to sour service.

6.1.4.2.3 Hot Induction Bending

6.1.4.2.3.1 General

Hot induction bending of pipe shall be performed in accordance with the requirements given for ISO 15590-1 PSL 2 or ASME B16.49 as an alternative.

6.1.4.2.3.2 Essential Variables for Hot Induction Bending

For all steels and nickel alloys, the essential variables of the manufacturing procedure specification (MPS) qualification shall be in accordance with ISO 15590-1. For clad carbon and low-alloy steel bends, the essential variables shall be in accordance with ISO 15590-1; additionally, any change of the clad welding procedure shall be an essential variable.

6.1.4.2.3.3 MPS Qualification and Production Bend Testing

Each bend group, as defined by the essential variables referenced above, shall be qualified in accordance with ISO 15590-1 and this section before commencement of production bending.
All testing of the qualification and production bends in carbon/low-alloy steel shall be in accordance with ISO 15590-1. For stainless steel, nickel-based alloys, and clad carbon/low-alloy steels, the test requirements defined in Table 6 should apply.

### Table 6—Testing of Qualification and Production Bends for Stainless Steels, Nickel Alloys and Clad Pipe

<table>
<thead>
<tr>
<th>Type of Test (^a)</th>
<th>Duplex SS</th>
<th>Austenitic SS and Nickel Alloys</th>
<th>CS Clad</th>
<th>Test Conditions and Acceptance Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tensile</td>
<td>T</td>
<td>T</td>
<td>T</td>
<td>In accordance with mother pipe specification</td>
</tr>
<tr>
<td>Impact</td>
<td>T</td>
<td>NA</td>
<td>T</td>
<td>See 6.1.1</td>
</tr>
<tr>
<td>Through-thickness hardness</td>
<td>NA</td>
<td>NA</td>
<td>T (^bc)</td>
<td>See 6.1.1</td>
</tr>
<tr>
<td>Surface hardness (^a)</td>
<td>NA</td>
<td>NA</td>
<td>T and P</td>
<td>See 6.1.1</td>
</tr>
<tr>
<td>Microstructure</td>
<td>T</td>
<td>T</td>
<td>T (^e)</td>
<td>See 6.1.1</td>
</tr>
<tr>
<td>Corrosion</td>
<td>T (^d)</td>
<td>T (^d)</td>
<td>NA</td>
<td>See 6.1.1</td>
</tr>
<tr>
<td>Bend test</td>
<td>NA</td>
<td>NA</td>
<td>T (^c)</td>
<td>See ASME BPVC Section IX</td>
</tr>
<tr>
<td>Surface NDT</td>
<td>T and P</td>
<td>T and P</td>
<td>T and P</td>
<td>—</td>
</tr>
<tr>
<td>Volumetric NDT</td>
<td>NA</td>
<td>NA</td>
<td>T and P</td>
<td>—</td>
</tr>
</tbody>
</table>

\(T\): required for each MPS qualification test bend.  
\(P\): required for each production bend.  
\(NA\): not applicable.  

For definition of further abbreviations, see 15590-1.

\(^a\) Test locations shall conform to ISO 15590-1.  
\(^b\) The clad layer and interface to carbon or low-alloy steel should be tested in accordance with ASME BPVC Section IX.  
\(^c\) For clad pipe bends, the MPS qualification should repeat the mechanical testing from the clad PQR/WPQR, i.e. side bend and hardness tests (including HAZ), see ANSI/API Spec 6A PSL 3.  
\(^d\) The corrosion test is applicable only to stainless steels with \(\text{PREN} > 40\).  
\(^e\) The cladding of carbon or low-alloy steel should be 100% inspected with liquid penetrant (LP) and bond line integrity with ultrasonic testing (UT) in accordance with ANSI/API Spec 6A PSL 3.

### 6.1.5 Forged Materials

#### 6.1.5.1 General

Forgings, including forged fittings, for pressurized components shall conform to an appropriate reference standard suitable for the application, for example those listed in Table 7.

In addition to the requirement listed in Table 7, all components shall be forged to a reduction 4:1 in the product forging operation and heat-treated in or as close to near-net shape as practicable.

The HIP process as given in ASTM A988/A988M is an acceptable alternative to forging.

#### 6.1.5.2 Nondestructive Inspection of Forgings

Forgings should be 100% surface-inspected by magnetic particle or dye penetrant method as given in the standards referenced by the applicable product standard. The testing should be performed in the final machined condition. Nonmachined surfaces shall be appropriately prepared before testing. The acceptance criteria are those given in ANSI/API Spec 6A PSL 3 (bodies) or ASME BPVC VIII, Div. 1, Appendix 6 or 8 as relevant, or equivalent.
Table 7—Material Standards for Forged Pressure-containing Components

<table>
<thead>
<tr>
<th>Material Type</th>
<th>ASTM Standard</th>
<th>EN Standard</th>
<th>ISO Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon or low-alloy steel</td>
<td>A182/A182M, A350/A350M, A508/A508M, A694/A694M, A707/A707M</td>
<td>10222-4</td>
<td>15590-3</td>
</tr>
<tr>
<td>Type 22/25Cr duplex</td>
<td>A182/A182M</td>
<td>10222-5</td>
<td>—</td>
</tr>
<tr>
<td>Austenitic stainless steel</td>
<td>A182/A182M</td>
<td>10222-5</td>
<td>—</td>
</tr>
<tr>
<td>Nickel alloys</td>
<td>B564</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>718</td>
<td>API 6ACRA</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

Carbon or low-alloy steel forgings should be 100% volumetrically inspected by ultrasonic testing. The testing shall be performed in accordance with ASTM A388 or EN 10228-3. The acceptance criteria shall be to ANSI/API Spec 6A PSL 3 (bodies), EN 10228-3 quality class 3, or equivalent.

Volumetric inspection of duplex or austenitic stainless steel forgings is recommended. When required, the forging shall be inspected by ultrasonic testing as given in EN 10228-4 or ASTM 388:

a) Scanning with normal probes in two directions is required.

b) Near-surface examination is not required.

c) The acceptance criteria shall be in accordance with API 6A PSL-3 or greater.

d) The 6 dB drop technique shall be used for the flaw length sizing of discontinuities.

e) The reference block distance amplitude correction (DAC) technique shall be used for sensitivity setting. The blocks shall be in the same heat-treatment condition and with the same sound attenuation as the forging, which should be tested.

f) A written procedure should be established. A description (sketch) of the reference blocks used for sensitivity setting shall be included.

g) Angle probes shall be used in accordance with ASME Section V Article 4 or EN 10228-4. In such cases, the use of angle probes using longitudinal waves are recommended.

6.1.5.3 Test Sampling of Pressure-containing Forgings

Testing of forgings shall be conducted on a heat per heat treat lot basis. Test sampling should be conducted per either NORSOK M-630 applicable MDS or DNVGL-RP-0034 applicable Steel Forging Class.

6.1.6 Fastener Materials

Pressure-containing fasteners shall conform to the requirements of API 20E or API 20F, BSL Level 2 minimum requirement shall be satisfied.

Non-pressure-containing fasteners shall have a maximum hardness of 34 HRC and conform to the requirements of:
— ASTM A193; or
— ASTM A320; or
— ISO 898 Gr 8.8; or
— ISO 3506 Gr A4.

6.1.7 Non-Metallic Materials

Non-metallic materials such as seal elastomers, composite pipe, and composite structural materials shall conform to API 17A or with the relevant ASTM standards.

6.2 Welding

6.2.1 General

Material to be welded should have weldability properties suitable for all stages of component manufacture, fabrication, and installation.

For pressure-containing applications, carbon and low-alloy steels should have the limitations in sulphur content as specified in Table 8 for both for sour and non-sour service.

<table>
<thead>
<tr>
<th>Type of Product</th>
<th>Sulfur Content, S % mass fraction</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Non-Sour Service</td>
</tr>
<tr>
<td>Rolled plate products</td>
<td>$S \leq 0.015$</td>
</tr>
<tr>
<td>Seamless pipe</td>
<td>$S \leq 0.015$</td>
</tr>
<tr>
<td>Forged products</td>
<td>$S \leq 0.025$</td>
</tr>
</tbody>
</table>

For carbon and low-alloy steels that are heat-treated by the quench-and-tempering or normalization-and-tempering process and subjected to PWHT during fabrication, the selected minimum tempering temperature shall be sufficiently high to allow PWHT and still meet the minimum specified mechanical properties. Alternatively, the base material may be tested in the simulated PWHT condition.

6.2.2 Structural Welding

Welding requirements and qualifications shall be based on an applicable industry standard, such as ASME BPVC Section IX, AWS D1.1, EEMUA 158, DNVGL-OS-C401 or ISO 15614-1 and the additional requirements from this standard.

6.2.3 Pressure-containing Welding

6.2.3.1 General

All pipe welding and related activities should satisfy the requirements of ISO 3834-2 or ASME BPVC, and the additional requirements of Section 6 of this document.

The welding procedure specification (WPS) shall be established for all welding intended for use in the fabrication of pressure-containing systems. The WPS shall contain the information listed in ISO 15609 or ASME BPVC IX.
The root pass of welds in stainless steels type 6Mo, type 25Cr duplex, and nickel alloys for lines carrying raw seawater shall be made with filler metal.

A non-slag-producing welding process should be used for the root pass on all single-sided welds in all stainless steels, nickel-based, and other CRA materials. The same applies to single-sided welds in carbon steel piping systems with required cleanliness. The system designer or end user shall specify such systems.

Socket welds shall not be used in pressure-containing piping unless accepted by the end user.

All fillet welds directly welded to pressure-containing piping systems work should be continuous.

No welding is permitted in cold-work areas, e.g. in cold-bent pipe.

Prefabrication of stainless steels and nickel-based alloys should be performed in a workshop, or parts thereof, that is reserved exclusively for such types of material.

Contamination of weld bevels and surrounding areas with low-melting-point metals such as copper, zinc, etc., is not acceptable.

For welding of high-alloy austenitic stainless steels with PREN $\geq 40$ (e.g. UNS S32654 and UNS S34565), the requirements given for stainless steel type 6Mo of this document shall apply.

NOTE Though useful, these indices are not directly indicative of the resistance to produced oil and gas environments. The most common examples are given in Equations (1) and (2):

\[
 f_{\text{PREN}} = w_{\text{Cr}} + 3.3w_{\text{Mo}} + 16w_{\text{N}} 
\]

\[
 f_{\text{PREN}} = w_{\text{Cr}} + 3.3(w_{\text{Mo}} + 0.5w_{\text{W}}) + 16w_{\text{N}}
\]

where

- $w_{\text{Cr}}$ is the mass fraction of chromium in the alloy, expressed as a percentage of the total composition;
- $w_{\text{Mo}}$ is the mass fraction of molybdenum in the alloy, expressed as a percentage of the total composition;
- $w_{\text{W}}$ is the mass fraction of tungsten in the alloy, expressed as a percentage of the total composition;
- $w_{\text{N}}$ is the mass fraction of nitrogen in the alloy, expressed as a percentage of the total composition.

6.2.3.2 Interpass Temperature

For fabrication welds, the approved range for the interpass temperature shall extend from the preheat temperature to the maximum interpass temperature recorded during the welding of the test piece, or to the following temperatures:

- 480 °F (250 °C) maximum for carbon and low-alloy steels;
- 300 °F (150 °C) maximum for stainless steels and nickel alloys.

6.2.3.3 Shielding and Purging Gas

Purging gas shall be used for welding of all stainless steel and non-ferrous materials and should be maintained during welding of at least the first three passes. The same requirement also applies for tack welding.

Shielding gases for welding of duplex stainless steels should contain less than 0.1 % hydrogen.
When welding duplex stainless steels, the use of gas mixtures with additions of nitrogen is recommended in order to maintain weld root corrosion-resistance properties.

### 6.2.3.4 Welding of Clad Materials

When joining clad pipe or clad components with access from outside only (single sided weld), a consumable compatible with the cladding shall be selected. Typically, a matching nickel-based consumable shall be used when closing the clad root of Alloy 625 clad components. Matching consumable must be maintained for fill and cap.

However, if welding configuration allows for access from both sides, a consumable compatible with the carbon or low-alloy steel wall shall be selected. The cladding shall be removed (cut back) from the root area, and the welding of the carbon or low-alloy steel wall completed before cladding is (re)applied to the root area. Carbon steel or low-alloy steel weld metal shall not be deposited onto a high-alloy base material or weld metal.

### 6.2.3.5 Welding of O-Lets

Only o-lets designed for volumetric inspection shall be used. The weld bevel of o-lets shall be filled up to the weld line on the o-lets. Smooth transition between the pipe and the o-lets is required. Notches below the weld line should be avoided. Prior to welding of the o-lets, a sufficient root gap shall be verified.

### 6.2.4 Welding Consumables

#### 6.2.4.1 General

All welding consumables shall have individual marking.

All extra-low- and low-hydrogen consumables for carbon steels, and all consumables for welding of stainless steel type 6Mo, type 22Cr or 25Cr duplex and nickel alloys should be delivered with certification of chemical analysis as given in ISO 10474 or EN 10204 Type 3.1.

Batch testing of the welding consumables is also acceptable. The welding and testing shall be carried out as required for a welding procedure qualification record (PQR/WPQR) for the actual material.

Consumables for other materials and fluxes for submerged arc welding processes shall be delivered with certification according to ISO 10474 or EN 10204 Type 2.2.

Handling and storage of consumables shall follow the manufacturer's recommendations.

#### 6.2.4.2 Carbon and Carbon Manganese Steels

For welding carbon and low-alloy steels having SMYS $\geq 415$ MPa, low-hydrogen type consumables (diffusable hydrogen (HD) $< 8$ ml/100 g weld metal or AWS H8) or solid-wire consumables should be used.

For water-injection systems in carbon steel, the root and hot pass should be made using low-alloy consumables containing either:

- (0.8 to 1.0) % mass fraction Ni; or
- (0.4 to 0.8) % mass fraction Cu plus (0.5 to 1.0) % mass fraction Ni.

**NOTE** This requirement is related to preferential corrosion experienced in weld metal of pipes.
For systems with sour service requirements, welding consumables that produce a deposit containing more than 1 % mass fraction Ni are acceptable after successful weld sulfide stress-cracking qualification testing in accordance with ISO 15156-2.

6.2.4.3  Austenitic Stainless Steels (Type 6Mo and Nickel-based Alloys)

A matching consumable with enhanced Mo or Cr content compared to the base material should be used. The sulphur content shall not exceed 0.015 % mass fraction.

6.2.4.4  Duplex Stainless Steels

A matching consumable with enhanced Ni content compared to the base material should be used. The sulphur content shall not exceed 0.015 % mass fraction.

Fillet or socket welds should not be made using duplex stainless steel consumables.

NOTE  Failures of fillet welds have occurred using duplex stainless steel consumables (see DNVGL RP F112).

6.2.4.5  Consumables for Joining of Dissimilar Materials

The filler material used in buttering layer when welding carbon steels to stainless steel type 316 should be as given in ASME BPVC II, Part C, SFA 5.4 E 309Mo, ASME BPVC II, Part C, SFA 5.9 ER 309L, or a nickel-based alloy.

When welding high-alloy stainless steel to carbon steels, the same high-alloy filler metal as used for welding the stainless steel to itself should be used.

When welding stainless steel alloyed with nitrogen, e.g. type 22Cr/25Cr duplex or type 6Mo, to carbon or low-alloy steels, it is recommended to use weld consumables without Nb alloying. This is due to precipitation of niobium nitrides, which can have a negative effect on ductility and corrosion properties and on the ferrite/austenite structure balance in the HAZ of the duplex alloys.

If PWHT is required for dissimilar joints, the weld deposit should be made using a nickel-based consumable. Additional requirements can be found in 6.2.7.

6.2.5  Welding Inspection and Qualification of Welding Inspectors

Welding inspectors should be familiar with relevant standards, rules, and specifications, and verify that all requirements and relevant parts in ISO 3834-2 are implemented and followed.

Welding inspection should be performed and documented before, during, and after welding.

Prior to fabrication start-up, the contractor should implement a system for recording and reporting weld inspection results. The inspection frequency shall be based on the scale and scope of the fabrication and approved by the end user. Causes for non-conformance should immediately be investigated and corrective action should be taken to prevent further occurrence. Non-conformance should require documented investigation/action by the responsible welding coordinator/responsible welding engineer.

Welding inspectors shall be qualified in accordance with one or more of the following:

— a Certified Welding Inspector (CWI) scheme equivalent to the requirements of AWS B5.1. CWI schemes may include internationally accepted programs such as the Certification Scheme for Personnel (CSWIP) or the Canadian Welding Bureau (CWB);

— NS 477 or European Federation for Welding, Joining and Cutting (EWF)/International Institute of Welding (IIW);
— welding inspector to FBTS (Brazilian Federation of Welding Technology) Level 1 and 2; IRAM (Argentina Institute of Standards and Certification) Level I and II should also be considered acceptable;

— the AWS inspector should be CWI or SCWI. The CSWIP inspector should be Level 3.1 or 3.2. The CWB inspector should be Level 1 or 2, or

— internationally recognized equivalent.

6.2.6 Welding Operator Qualification

All welders and welding operators shall be qualified in accordance with ISO 9606-1, ISO 14732, or ASME BPVC Section IX, AWS D1.1, or equivalent codes.

6.2.7 Post-weld Heat Treatment

If PWHT is used to improve the resistance of welded joints to stress corrosion cracking, then the PWHT qualification should be performed for all thicknesses.

The PWHT temperature shall be at least 20 °C lower than the base material tempering temperature. Alternatively, the base material may be purchased with a simulated PWHT test that meets the mechanical property requirements. The PWHT cycle shall be in the same temperature range and minimum soak time as will be used on the production part.

The PWHT qualification shall be approved by the end user when the PWHT involves assemblies with dissimilar material joints.

6.2.8 Weld Repair

All weld repairs should be made in compliance with the applicable welding specification. Repair welding shall be performed using either the same WPS as for the original weld, or a separately qualified procedure.

Before repair welding, the defect should be verified to be completely removed.

After repair welding, the complete weld and adjacent weld and base metal shall be subjected to at least the same NDT as specified for the original weld.

Repair welding should not be carried out more than twice in the same area. For welds in stainless steel types 6Mo and 25Cr duplex, only one attempt at repair is acceptable in the same area.

When the original WPS is used for weld repairs, the qualified range of PWHT time and temperature should not be violated. Pre-PWHT inspection may be required in some cases.

6.2.9 Welding Coordination

All welding coordination should be conducted as described in ISO 14731. The manufacturer should appoint an authorized welding coordinator responsible for the contract/project/fabrication site. The responsible welding coordinator should be qualified as an International Welding Engineer (IWE) or as otherwise accepted as given in ISO 14731.

All personnel who carry out one or more welding activities as given in ISO 14731 are welding coordinators. The level of technical knowledge, tasks, responsibility, and authority should be defined for each person/function.

6.2.10 Overlay Welding and Buttering of Components

6.2.10.1 General

The requirements of this section are given to qualify weld-overlay procedures for:
— corrosion-resistant overlay;
— weld buttering.

Overlay welding shall be performed with gas tungsten arc welding (GTAW) or pulsed gas metal arc welding (GMAW) unless it is agreed to use other methods.

### 6.2.10.2 Corrosion-resistant Overlay

Qualification of welding procedures for weld overlay shall conform to API 6A PSL 3.

Overlay thickness should be at least 0.12 in. (3.0 mm) unless another thickness is specified. For the nickel-based alloy UNS N06625 (AWS ERNiCrMo3), the chemical composition shall conform to API 6A Class Fe 10 unless specified otherwise by the end user.

**NOTE** The end user may require use of API 6A Class Fe 5 for zone 3 of ISO 15156-3.

All weld overlay surfaces should be quality controlled in accordance with API 6A PSL 3 unless specified otherwise.

### 6.2.10.3 Weld Buttering

Buttering of the weld prep of a component that will become a part of a pressure-containing butt weld, (e.g. as a transition between a corrosion-resistant alloy and a carbon or low-alloy steel), shall be qualified and fabricated as a butt weld (see 6.2.11). Weld consumables for buttering shall be considered an essential variable. A prolongation should be welded to the buttering to facilitate extraction of the mechanical specimens.

In addition to the mechanical tests required of a butt weld, one all-weld tensile test shall be prepared and carried out. The yield and tensile strength of the weld should match the material with the lower minimum specified strength of abutting materials in the final connection.

**NOTE** A few failures, but with high economic consequence, have occurred in nickel-based alloy butter welds on low-alloy steel components. Different solutions are being developed in the industry.

Specific weld details and procedures shall be agreed between the contractor and the end user.

The thickness should be at least 8 mm in finished condition. The heat-affected zone of the weld cap of the closure weld shall be completely within the buttered layer.

All weld buttering should be nondestructively tested as follows:

— 100 % surface testing by magnetic particle or dye penetrant methods, as relevant to the material after machining of the bevel. No relevant indications are allowed on the bevel surfaces.

— 100 % volumetric testing by ultrasonic and/or radiography methods, including the interface zone. Acceptance criteria are the same as used for butt welds.

### 6.2.11 Pressure-containing Welding Qualification

#### 6.2.11.1 General

Welding procedures for fabrication of steels and nickel-based alloys shall be qualified as given per ASME BPVC IX or as in ISO 15614-1 and the remaining provisions of this section.
All pressure-containing and overlay welds should be qualified according to API SPEC 6A PSL 3. The welding standard shall be ASME BPVC IX or ISO 15614-7.

6.2.11.2 Testing of Weld Test Specimens

All test joints should be examined visually and nondestructively by surface and volumetric methods, for example in accordance with 6.1.3.3 following any required PWHT and prior to cutting of the test specimens.

6.2.11.3 Mechanical Testing

6.2.11.3.1 General

Companies performing material testing shall have a quality management system. The quality management system should conform to ISO/IEC 17025 or equivalent.

Mechanical testing shall be performed in accordance with ASME BPVC IX or the relevant part of ISO 15614 and the additional requirements in this document.

If a specimen fails to meet the test requirements, two sets of retests for that test may be performed with specimens cut from the same procedure qualification test coupon. The results of both retest specimens shall meet the specified requirements.

6.2.11.3.2 Impact Tests

Impact testing is required of welds with wall thickness \( \geq 6 \) mm and shall meet the requirements of Table 9. Alternatively, when agreed with the user, other impact test requirements may be applied (e.g. API 6A impact test requirements).

### Table 9—Impact Test Requirements

<table>
<thead>
<tr>
<th>Material</th>
<th>Notch Location ab</th>
<th>Test Temperature</th>
<th>Acceptance Criteria cd</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon steel with SMYS &lt; 415 MPa</td>
<td>WM, HAZ</td>
<td>MDT or lower</td>
<td>25 J</td>
</tr>
<tr>
<td>Carbon steel and low-alloy steel with SMYS ( \geq ) MPa</td>
<td>WM, HAZ</td>
<td>–46 or MDT, whichever is lower</td>
<td>35 J or lateral expansion at least 0.38 mm</td>
</tr>
<tr>
<td>Type 22Cr and 25CR duplex</td>
<td>WM, HAZ</td>
<td>–46 or MDT, whichever is lower</td>
<td>35 J or lateral expansion at least 0.38 mm</td>
</tr>
</tbody>
</table>

a WM: at weld metal centreline;  
HAZ: located with the fusion line through the centreline of the vertical V-notch, or including as much of the HAZ as possible.  
b Root WM and HAZ samples should be taken when weld thickness is greater than 20 mm, and if PWHT is not applied.  
c No single energy value should be below 75 % of the average requirement.  
d Reduction factors of energy requirements for sub-size specimens are \( \frac{5}{6} \) for 7.5 mm specimens and \( \frac{2}{3} \) for 5 mm specimens.

If two types of material are welded together, each side of the weld should be impact tested and shall fulfill the requirement for the actual material. The weld metal shall fulfill the requirement for the least stringent of the two materials.

6.2.11.3.3 Hardness Tests

Hardness testing is required for welds in all carbon and low-alloy steels. For austenitic stainless steels and nickel alloys, hardness testing is required when sour service is applicable in accordance with ISO 15156 (all parts).
Hardness tests should be made at a macro-section and shall be performed in accordance with ISO 15156 (all parts). When repair weld procedures applicable for sour service are required by the specification, hardness testing should be carried out as given in ISO 15156-2. Hardness testing to ISO 15614-1 is accepted for other materials and when sour service is not required.

Hardness limit for carbon- and low-alloy steels including HAZ in fully clad systems shall follow hardness limitations for non-sour service in Table 10.

NOTE When welding closing welds with nickel alloy consumables, PWHT may not be feasible and low heat input may need to be applied to avoid solidification cracking. For such welds, hardness limits as given in ISO 15156 may not be achievable. If long term integrity of the cladding can be predicted, non-sour conditions should be considered.

The acceptance criteria used for hardness measurement should be as given in Table 10 and ISO 15156 (all parts).

Table 10—Hardness Limitations to Avoid Hydrogen Embrittlement Under Cathodic Protection

<table>
<thead>
<tr>
<th>Material</th>
<th>Maximum Hardness</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon and low-alloy steels for general applications (excluding bolting)</td>
<td>325 HV/33 HRC/329 HB</td>
</tr>
<tr>
<td>Martensitic and supermartensitic stainless steels</td>
<td>325 HV/33 HRC/329 HB a</td>
</tr>
<tr>
<td>Ferritic-austenitic stainless steels</td>
<td>Hardness has not been shown to be a determining factor in the sensitivity to hydrogen-induced stress cracking under cathodic protection; hence no hardness limit is specified. However, compliance with ISO 15156-3 is recommended.</td>
</tr>
<tr>
<td>Austenitic stainless steels</td>
<td>For these materials, hydrogen embrittlement is not considered an issue under cathodic protection, hence no hardness limit is specified.</td>
</tr>
<tr>
<td>Nickel alloys</td>
<td>See ISO 15156-3.</td>
</tr>
</tbody>
</table>

NOTE Heat treatment and weld procedures should be designed to avoid microstructural defects such as sigma-phase in duplex stainless steels and delta phase in age-hardened nickel alloys.

a Based on 325 HV, hardness conversion to HRC based on ASTM E140, conversion HRC to HBW based on tests by Foroni Metals relationship

\[
HRC = 43.796 \times \ln(\text{HBW}) - 220.86.
\]

6.2.11.3.4 Corrosion Testing

Fabrication welds in stainless steel type 6Mo, type 25Cr duplex should be corrosion-tested as given in ASTM G48, Method A. The test temperature shall be 104 °F (40 °C) and 95 °F (35 °C) for 6Mo and 25Cr duplex, respectively, and the exposure time shall be at least 24 h.

The test shall expose the external and internal surfaces of the weld and along the weld. The test specimen should have the dimensions of full wall thickness by 1 in. (25 mm) along the weld by 2 in. (50 mm) across the weld. Cut edges shall be prepared in accordance with ASTM G48.

NOTE 1 Test specimens may include weld stops and starts on both ID and OD surfaces.

When pickling is used, the whole specimen shall be pickled before being weighed and tested. Pickling may be performed for 5 min at 140 °F (60 °C) in a solution of 20 % volume fraction HNO3 + 5 % volume fraction HF.

NOTE 2 See ASTM G48 for surface preparation, which can significantly influence results.

The acceptance criteria are as follows:
— no pitting at 20× magnification;
— mass loss should not exceed 4.0 g/m².

As an option, if required, welds in stainless steel type 22Cr shall be corrosion-tested as defined above. The test temperature shall be 72 °F (22 °C), and acceptance criteria shall be as defined above.

6.2.11.3.5 Microstructural Examination

Duplex stainless steel should be examined for acceptable microstructure. The test samples shall comprise a cross-section of the weld metal, heat-affected zone, and the base metal of the pipe. Microstructure shall be examined for detrimental phases in accordance with ASTM A923 Method A. The microstructure shall be suitably etched and examined at a minimum 400 magnification and should have grain boundaries with no continuous precipitations; the intermetallic phases, nitrides, and carbides should not in total exceed 0.5 % of the examined surface area.

In case of amounts of intermetallic phases greater than the limit stated above, the acceptability of PQR/WPQR shall be based on corrosion and/or impact testing for large bore pipe.

For duplex stainless steel, the ferrite content in the weld metal root and in the unreheated weld cap shall be determined in accordance with ASTM E562 and should be in the range of 30 % volume fraction to 70 % volume fraction.

6.2.11.4 Essential Variables

6.2.11.4.1 General

Requalification of a welding procedure is required on any of the changes in the essential variables listed in ISO 15614-1, ISO 15614-7, or ASME BPVC IX, and the additional essential variables listed in 6.2.11.4.2 to 6.2.11.4.8.

6.2.11.4.2 Base Material Changes Requiring Requalification

The following changes in base material require requalification of the welding procedure:
— change from lower than 24Cr to higher than 24Cr;
— change from any other material to type 6Mo;
— for type 25Cr duplex with wall thickness ≤ 8 mm, a separate welding procedure qualification test should be carried out on the minimum wall thickness that will be welded;

6.2.11.4.3 Filler Material Changes Requiring Requalification

A change in the specific make or brand may be made, provided the results of weld metal impact testing satisfy the requirements of Table 9.

6.2.11.4.4 Welding Process Changes Requiring Requalification

A change from single-wire to multiple-wire system, or the converse, requires requalification.

6.2.11.4.5 Heat Input Changes Requiring Requalification

The heat input requirements shall be per the applicable welding standard used for the qualification test.
6.2.11.4.6 Welding Position Changes Requiring Requalification

A change from vertical upward to vertical downward, or the converse, requires requalification.

6.2.11.4.7 Changes in Technique Requiring Requalification

A change from multi-pass to single-pass technique requires requalification.

6.2.11.4.8 Joint Changes Requiring Requalification

For bevel angles less than 30°, a decrease in bevel angle requires requalification.

6.3 General and NDT Personnel Qualification

The requirements in 6.4 shall be in addition to or shall replace the corresponding requirements in the relevant reference standards.

Personnel performing visual inspection or nondestructive testing shall be certified for the test method used in accordance with:

— ASME BPVC V or ISO 9712 for visual inspection;
— ISO 9712, ASNT Central Certification Program (ACCP), or ASNT-SNT-TC-1A Level II for NDT methods.

The roles and responsibilities of NDE personnel shall be as defined in ISO 9712 or as defined in ASNT SNT-TC-1A.

7 Material Traceability

All pressure-containing and pressure-controlling parts of equipment manufactured according to this document should conform to the requirements of API 6A PSL 2 or API 6A PSL 3. These PSL designations define different levels of requirements.

It is not necessary that structural components and other non-pressure-containing/controlling parts of equipment manufactured according to this document conform to the requirements of API 6A PSL 2 or API 6A PSL 3.

8 Transportation and Preservation

8.1 General

It is recommended that the subsea production system:

— be equipped with lifting points and primary-load-bearing structures that are certified and labeled in accordance with statutory requirements;
— be equipped with transportation skids as relevant;
— be designed for transportation in a safe manner;
— be equipped with facilities to enable attachment of sea-fastenings certified in accordance with statutory requirements.

The piping system and valves should be filled with a preservation fluid prior to delivery, and should take into account environmental conditions that may be encountered.
8.2 Storage and Preservation Procedure

A written storage and preservation procedure should be implemented, detailing regular and periodic inspection and maintenance. This procedure should address the following topics:

— draining after testing;
— corrosion prevention;
— sealing-surface protection;
— hydraulic systems;
— exercising of valves;
— environmental conditions (i.e. maximum and minimum temperature and UV on equipment);
— electrical systems.

8.3 Sea-fastening

The sea-fastening of subsea structures shall be incorporated into the functional requirements during the design phase. The sea-fastening methods shall meet typical industry standards, such as the Noble Denton Technical Guideline 0030/NDI Rev 3.

Friction shall not be considered as a force component in the sea-fastening design.

9 Installation/Retrieval of Structures and Components

9.1 Installation/Retrieval General Requirements

The template or support structure should provide sufficient functionality and capability to meet the installation/retrieval requirements. Different types of installation vessel, such as drilling rigs, subsea construction vessels, or crane barges should be evaluated when developing the installation/retrieval requirements.

During the design phase, offshore vessel lifting capabilities and offshore handling should be treated as a design input.

Installation requirements may include some or all of the following items:

— loadout;
— allowance for lifting with rig crane (when relevant);
— minimization of any special transportation requirements;
— transportation to site;
— launch capability;
— crane capacity;
— buoyancy capability;
— ballast/flooding system;
— system for lowering to seabed;
— allowance for added mass effects and dynamics of the lowering system;
— ability to be accurately positioned and potentially repositioning;
— leveling system (see 5.5.7);
— barge size and load capacity;
— moonpool size (if applicable);
— foundation interface.

Subsea structures and modules should be designed so that they can be installed/retrieved using standard offshore installation methods without the need for purpose-designed installation aids. Restrictions with regard to sequence of marine installations and drilling rig activities should be minimized.

During installation/retrieval, subsea production system equipment should:
— not rely on hydraulic pressure to retain the necessary locking force in (module-to-module) connectors;
— allow cessation of operations without compromising safety;
— allow testing/verification of interface connections after make-up;
— allow for quick, easy, and reliable make-up of modules;
— allow for draining of entrained water from hollow members and trapped volumes;
— have facilities for testing prior to deployment, (where applicable);
— facilitate orientation and guidance during installation;
— incorporate shock absorbers or any soft landing devices as required, in order to allow for specified maximum landing velocity;
— minimize the ingress of water or contamination into hydraulic and barrier fluid circuits during connection;
— avoid loss of harmful fluids during installation and operation;

The equipment supplier should develop an installation requirements and limitations document which includes an outline installation procedure as input for the installation contractor. The following information shall be included in the document(s):
— maximum acceleration, retardation, lowering speed, and landing speed;
— procedure for lowering through splash zone;
— installation tolerances and proposed methods for their verification;
— maximum out-of-level allowance prior to leveling;
— loads and restrictions for sea-fastening and transport;
— well spudding tolerances (if rig contractor is responsible for installation as well);
— installation aid interfaces.

Structures should be designed to maximize installable sea states.

Safe personnel access to lifting points on the structures should be provided by implementing safety harness attachment points, ladders, and grating where required.

Dedicated points or areas for sea-fastening of the modules and structures should be identified and designed for the applicable loads (see 8.3).

9.2 Installation Method and Tools

In the design of the subsea production system, the following installation tooling functionality should be included:

— installation tools that do not cause obstructions or restrict intervention access;
— installation tools with a fail-safe design;
— lifting devices that include provision for the attachment of tugger lines and handling points;

NOTE 1 A laydown area, platforms and support for installation instrumentation, temporary access ladders, and inspection platforms may be required.

— disconnection of lifting devices consistent with the intervention strategy;

NOTE 2 A backup system to release lifting devices may be provided.

— position indicators on all subsea intervention actuated connections;
— capability to video record installation operations;
— provision for flushing of hydraulic circuits subsequent to connection of interfaces (see Section 11.2.1);
— minimal time the installation vessel is tethered to the equipment;
— minimal number of installation vessels used;
— minimal number of special installation tools used;
— maximum number of classes of vessels which can perform the installation;
— installation within a defined practical weather window that is consistent with the specific type of installation equipment and vessel being used;
— that which facilitates fully reversible sequential installation techniques/operations.

9.3 Hook-up and Commissioning

This section defines the recommendations for precommissioning/commissioning of subsea production systems. The activities taking place from the platform/topside vessel are covered.

The main purposes of precommissioning/commissioning are to:
— verify satisfactory integrated operation of the total subsea production system;

— verify all interfaces to platform systems;

— demonstrate that the subsea production system is ready for start-up.

Precommissioning/commissioning can be subdivided in the following activities:

a) verification of topside-located subsea production control equipment;

b) verification of topside-located equipment that can be defined as utility systems for the subsea production system;

c) verification of flowlines and flowline isolation valves; (see API 17TR11 for testing)

d) verification of the subsea production system.

9.4 Testing Requirements

Prior to installation, equipment should be subjected to an integration test. The precommissioning/commissioning procedures should be developed based on results from integration tests and the operating procedures. The precommissioning/commissioning activities described in this section can be relevant. Acceptance criteria should be developed for each test.

Typical activities include:

— verification of flowlines and flowline isolation valves;

— flowline pressure test;

— flowline dewatering;

— leak test of system valves;

— function test of subsea manifold valves;

— verification of subsea production system;

— test of insulation resistance and continuity of electrical distribution system;

— verification of communication with control module;

— functional test of subsea external sensor(s);

— leak test of hydraulic, chemical distribution, and barrier fluid systems.

9.5 Intervention Requirements

Intervention systems may be operated by divers, ROV, remotely operated tool (ROT), AUV, or other subsea vehicle. The design of subsea interfaces with the subsea production system shall be in accordance with API 17H.

It is recommended that the subsea template, structure, and its equipment be designed to provide the following functionality to facilitate efficient intervention:
— suitable viewing positions for observations during running, connection, and operation of tools, modules, and equipment;

— suitable landing area and/or attachment points where it is necessary to carry out manipulative tasks;

— protection for sensitive components/items on the subsea structure that can be damaged by the intervention system;

— bucket(s) designed for easy replacement of acoustic transponder(s) (acoustic shielding and potential snagging should be avoided);

— easy operation of all locking mechanisms on protection hatches and lifting frames, in accordance with the defined intervention strategy;

— replaceable guideposts having locking mechanisms operated by the selected intervention system;

— design of all permanently installed guideposts that require a guidewire attachment, such that a new guidewire can be reestablished in the case of a broken wire or pile over pull;

— any special equipment or arrangements installed on the subsea structure that require the application of torque during operation designed to use a dedicated torque tool and interface;

— anodes and other construction details located such that they do not represent any obstruction or snagging point for the selected intervention system;

— tools, BOP, modules, and all retrievable equipment having adequate running clearance to any part of the structure, adjacent module, or equipment.

— for guidelineless operations, provision of positive restrictions, such as guide funnels or bumper beams, to avoid impact between adjacent equipment.

10 Operation and Maintenance

10.1 Operability

Operability of the subsea facility is often critical to the success of a development. The purpose of this section is to provide a listing of operational requirements which often arise during the operation of subsea production systems.

The following operational requirements should be addressed during the design phase:

— drilling and completion prior to and after commissioning;

— hook-up and commissioning;

— reliability/availability of the system;

— intervention;

— component change out;

— maintenance;

— decommissioning.
10.2 Maintenance

10.2.1 General

Equipment should be designed and validated to avoid subsea maintenance for the life of the field. When maintenance is required, planning for maintenance should begin during the design of the subsea systems. Potential maintenance tasks should be identified, optional approaches evaluated, and selections made for maintenance provisions for incorporation into subsea systems and hardware. In some cases, simple and basic maintenance methods (e.g. divers with hand tools) may be used, while in other applications remote diverless tools are required.

Special maintenance tools and procedures should be thoroughly tested and evaluated prior to use offshore. Maintenance procedures should be developed and, if practical, full-scale tests performed. Detailed photos and/or video documentation of subsea hardware interfacing with maintenance tools interfacing is recommended.

Detailed procedures should be prepared prior to initiating any subsea maintenance operation. The procedure should indicate planned work, and define how the maintenance operation will be coordinated with other concurrent field activities. The procedure should list materials, equipment, and services required for the particular maintenance operation.

Maintenance of equipment located on or near the seabed (e.g. wellheads, trees, control modules, valves, manifold, templates, flowlines, flowline connectors, riser bases, and risers) can be carried out by modular replacement or in situ repairs. Modular or component replacement involves packaging repair/maintenance-prone items into composite units that can be removed to the surface for replacement or repair.

10.2.2 Seabed Maintenance

An effort should be made to diagnose and define a problem prior to initiating a maintenance operation. The affected well(s) should be shut in, and the subsea system should be put into a safe condition for removal/repair of the component requiring maintenance. For some subsea systems, it is possible to isolate the affected well(s) and continue normal operations. Prior to the execution of any maintenance operation, a detailed procedure should be developed in conjunction with the maintenance philosophy, intervention philosophy, and a risk analysis.

The detailed procedure should address the following:

— establishing a permit-to-work system, to preclude the possibility of operations personnel inadvertently operating the subject or related equipment until after it has been put into a safe condition;

— bleed-down any retained pressure to ambient conditions;

— prevent the release of contaminating fluids or hydrocarbons by flushing and retaining the fluid;

— using the same philosophy adopted for flowline connections in regards to environmental barriers (see section 5.1.4) for connection hubs for modules in piping;

— de-energizing electrical circuits if they pose a hazard for divers and other maintenance systems;

— lowering and recovering of tools and modules on drill strings or cables to minimize risks of damage to seafloor equipment by dropped objects or by impact during positioning or landing;

— thorough testing of the subsea system before returning to service;

— maintaining records of maintenance activities.
11 Abandonment

11.1 General

Projects should identify decommissioning and abandonment requirements during the design selection and approval. The requirements may change or be updated over the lifecycle of the asset. The decision to either recover/remove subsea equipment or abandon in place, is governed by local and international legislation and regulations. One of the primary drivers is water depth. In water depths greater than 1000 m, the best practical option for decommissioning could be to abandon in place when allowed by local regulations. This decision should be documented with a comparative risk assessment.

If subsea equipment is expected to be recovered at the end of the project, a decommissioning philosophy should be developed to identify principles to be used during the design phase. Decommissioning and abandonment requirements may influence design concepts and construction of subsea structures. During the development of the decommissioning philosophy, it should be assumed that end-of-life operations are executed utilizing best practice at the time of field start-up. The decommissioning philosophy shall comply with applicable regulations, legislation, and operating agreements.

11.2 Decommissioning

11.2.1 General

The elements related to the decommissioning of templates, manifolds, and foundations are:

— flushing equipment;
— removal of seabed equipment;
— seabed clean-up; and
— final survey.

Depending on local regulations, it may be permissible to abandon part or all of the system in-situ.

The subsea production system at decommissioning should:

— allow for the safe shutdown and end of operations;
— allow the flushing of produced fluids and chemicals from flowlines, storage tanks, manifolds, etc., prior to flooding with seawater;
— allow for the recovery of equipment to surface;
— allow the recovery of flushed fluids at the surface to avoid pollution.

11.2.2 Flushing

Decommissioning operations should follow general retrieval guidelines for flushing hydrocarbons and chemicals with inert fluids prior to retrieval. If subsea equipment is to be abandoned in place, it is recommended that templates and manifolds be flushed and cleaned using the most effective methods (i.e. pigged clean and/or flushed) and flooded with water. The discharge of hydrocarbons and chemicals should be avoided in order to minimize the impact to the environment during this operation.

NOTE The flushing process may be conducted in stages, such as flushing hydrocarbons with MEOH or dead oil and then flushing with water.

The flushing process includes:
— Flushing facilities to minimize hydrocarbon or other harmful fluid volumes trapped within the item to be retrieved. Flushing infrastructure should be designed to provide effective flushing of the module to be retrieved.

— A recommended flushing procedure that may also be part of the manufacturer documentation.

— If the system is to be retrieved or transported as a sealed assembly, a solution allowing for pressure relief during retrieval or transport should be incorporated as part of the design.

— Retrievable modules that should be designed to enhance flexibility in the choice of installation/maintenance vessels.

— Provisions that should be made for flooding and draining of structural steel during installation and retrieval.

### 11.2.3 Retrieval

The subsea production system should include elements and features designed for the life of the field and for use during decommissioning. This includes attachment points for lifting equipment and visual indicators on intervention points. When retrieval is required, the intended retrieval procedure should be reviewed and updated to incorporate best practices and technology developed.

A subsea survey of the equipment should be performed to assess the structural integrity of the equipment, including lifting points and ballasting systems, to ensure the equipment can be safely retrieved. The presence and condition of remaining anodes should be reviewed to help determine the condition of structural members that may not be visible by subsea inspection. After collecting the available information, a detailed plan for removal should be developed.

**NOTE** An important aspect for deployment of subsea equipment and the application of API 17TR12 is related to the temperature difference between subsea and surface conditions. A system flushed subsea and then closed-in prior to retrieval may see significant pressure increases as a result of thermal expansion of the trapped fluids. In addition to thermal expansion, trapped hydrocarbons may undergo a phase change as a result of the temperature rise during retrieval.

### 11.2.4 Post-abandonment Operation

After the abandonment operation, the site should be surveyed and mapped for remaining equipment. If equipment is abandoned in place, a post-abandonment philosophy should be developed outlining any periodic survey or other activities necessary to document the condition of the abandoned equipment.

### 11.3 Manifolds

Manifolds that are integrated into a template are normally abandoned with the template. Packaged manifolds designed for installation and removal by a drilling rig can be abandoned in conjunction with well abandonment. A separate manifold system, such as part of a riser base, requires its own abandonment analysis.

### 11.4 Templates

General guidelines for template removal are as follows:

a) Disconnect all risers, pipelines, flowlines, control and power umbilical/flying leads.

b) Piles, such as well casing, should be cut off at the required distance below mudline. The cut-off pile sections can require pulling to reduce suction effects and lift loads when the template is removed. If so, the template/pile connection should be broken so as not to damage the template structural integrity.

c) Removing the template requires a well-planned approach. Activities that can require detailed planning are lifting analysis, removal of cuttings and cement, jetting to reduce bottom suction, addition of flotation devices, and lifting of equipment.
d) The crane barge or lifting vessel should have adequate capacity to handle higher-than-expected loads. It is recommended that visual surface monitoring of the rigging-up and lifting be carried out using diver-held or subsea vehicle-mounted video cameras.

e) After the template is lifted and secured to a cargo barge, it can be transported to the chosen disposal site.

11.5 Foundations

Foundations may be abandoned in place or only partially retrieved even when the supported structure is to be completely retrieved. For partial retrieval, pile foundations should be cut or otherwise separated at or below the seabed to leave behind only the embedded portion of the foundation. Where full retrieval is required, this functionality shall be included during the design phase of the equipment, including soil consolidation due to duration of installation. Decommissioning retrieval analyses may indicate local buckling or plasticity so long as the safe handling of the equipment is not compromised.

Suction loads, especially for mudmat foundations, must be accounted for unless mitigated by overpressure beneath the bearing plate.

12 Qualification, Verification, Validation, and Testing

12.1 Design Verification

12.1.1 General

Design verification should be performed to ensure that the design output, as defined by the design plan, has been met.

Design verification can be achieved by, but is not limited to:

a) producing design documentation, such as drawings, specifications, and procedures;

b) performing design calculations as prescribed in Section 4;

c) performing design reviews according to 12.1.3;

d) hydrostatic testing.

NOTE Hydrostatic testing duration may be driven by regulatory requirements above pipeline code requirements.

12.1.2 Design Documentation

The design documentation should include, but is not limited to:

— assembly drawings (including as-built);

— detail design drawings;

— structural analysis;

— piping analysis;

— material selection analysis;

— specifications and data sheets;
— design review minutes of meeting;
— test procedures and records;
— report of weights and centers-of-mass for system components;
— HAZID, hazard and operability analysis (HAZOP), and safety and operability analysis (SAFOP) reports;
— operating and maintenance manuals:
  — storing and preservation procedures,
  — planned normal operating modes,
  — installation/retrieval procedures,
  — preventive maintenance schedules,
  — spare part lists,
  — load-out procedures,
  — commissioning/hook-up requirements and limitations,
  — decommissioning requirements and limitations;
— manufacturing data book:
  — as-built/as-installed documentation,
  — testing reports and records.

12.1.3 Design Reviews

Design review of the manifold system and components should be performed according to the design plan. The design plan should be developed with the guidance given in ISO 9001, API Spec Q1, DNV-RP-A203, or other recognized standard. The design review should include the following elements:

— review of design inputs;
— establishment of design outputs;
— material selection and review;
— review of conformance to end user requirements;
— shop handling and fabrication;
— review of internal interfaces;
— review of external interfaces;
— establishment of design verification requirements;
— establishment of design validation requirements;
— review of safety issues;
— ease of asset maintenance and operation;
— review of asset integrity requirements;
— installation issues;
— retrieval issues;
— intervention analysis, including subsea vehicle accessibility.

### 12.1.4 Factory Acceptance Testing

A comprehensive acceptance test program should be undertaken at the fabrication site to ensure that components have been manufactured in accordance with specified requirements. The test should be performed to a predefined and approved procedure. Any non-conformance should be documented and analyzed to find the reason for the failure. The nonconformance should be corrected. If the nonconformance cannot be corrected, a review of the calculated reliability of the system should be conducted to determine if the deviation can be accepted.

Factory acceptance testing is generally a multi-tiered approach, involving individual component checks, subsystem checks (e.g. control system), interface checks, and unitized system checks. Modifications and changes to the equipment during testing and manufacture should be formally documented.

A typical format for a subsea equipment factory acceptance testing procedure can include the following:

— purpose/objective;
— scope;
— requirements for fixtures/set-ups, facilities, equipment, environment, and personnel;
— performance data;
— acceptance criteria;
— reference information.

Factory acceptance testing typically covers the following items:

— individual component testing;
— assembly fit and function testing using actual subsea equipment and tools where possible;
— interface checks using actual subsea equipment and tools where possible;
— interchangeability testing;
hydrostatic testing:
- includes valve seal checks at operating pressure,
- verifies piping code requirements,
- duration according to design code, regulatory requirement, or 1 hour (recommended) if not specified;
- seal testing of end closures.

12.2 Design Validation

12.2.1 General

Design validation is achieved by:
- performing first article testing;
- performing qualification testing;
- performing system integration testing.

Design validation is performed to ensure that the specific operational requirements have been met. In certain cases, it is necessary to perform wet-simulation testing to prove correct functioning of components and systems under water.

Tests should include simulations of actual field and environmental conditions for all phases or operations, from installation through maintenance. Special tests can be required for handling and transport, dynamic loading, and backup systems. Performance tests can be appropriate and can supply data on response-time measurements, operating pressures, fluid volumes, and fault-finding and operation of shutdown systems.

12.2.2 Qualification Testing of Components

Individual components, such as valves, actuators, rotating equipment, pipe fittings, and control system components, shall be qualified independently of the manifold/template system. If the subsea structure uses features or components that require qualification, a testing program should be developed using previous experience or an industry guideline such as API 17N, API 17Q, or DNV-RP-A203.

12.2.3 System Integration Testing

While the total system integration test is outside the scope of this document, all of the subsea production system including manifolds, templates, PLEMs, PLETs, etc. should be part of the system integration test. The provisions of this section are provided as a guideline for a typical system integration testing with a subsea manifold. The tests performed during integration testing should be used to check reliability and should demonstrate tolerance requirements and correct functioning of the complete system. The purpose of the test is to simulate all operations that can be done offshore, to the extent practical, and to verify all equipment/systems related to the permanent seabed installations.

Training of personnel, including familiarization with equipment and procedures, is an important factor during integration test activities. This aspect is particularly important in order to promote competence, safety, and efficiency during installation and operation activities.

System integration testing typically comprises the following activities:
- documented integrated function test of components and subsystems;
— final documented function test, including bore testing and leak testing;
— final documented function test of all electrical and hydraulic control interfaces;
— documented orientation and guidance fit tests of all interfacing components and modules;
— simulated installation, intervention, and production mode operations, as practical, in order to verify and optimize relevant procedures and specifications;
— operation under specified conditions, including extreme tolerance conditions, as practical, in order to reveal any deficiencies in system, tools and procedures;
— operation under relevant conditions, as practical, to obtain system data such as response times for shutdown actions;
— testing to demonstrate that equipment can be assembled as planned (wet conditions as necessary) and satisfactorily perform its functions as an integrated system;
— filling with correct fluids and lubrication, cleaning, preservation, and packing as specified;
— final inspection in order to verify correctness of the as-built documentation;
— verification of made-up connections for the full operation envelope, e.g. between tree and manifold;
— functional test of manifold/template using workover control system;
— running and retrieving of control pods/flow control modules;
— pull-in and connection of umbilical (hydraulic/chemical lines and electrical connections) and flowlines;
— tolerance check of manifold system after reinstallation;
— pigging operations.

NOTE It is important to functionally test all manual-override functions in connection with the intervention tests. The purpose of the intervention test is to verify the subsea interfaces and the functions of the subsea vehicle systems and tooling, guidepost/minipost replacement, and mechanical override of connectors. Tests using any company-provided items should be performed to verify interfaces and functions.
# Annex A
(informative)

## Typical manifold data sheet

<table>
<thead>
<tr>
<th>General</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Foundation Type</td>
<td>Estimated Weight</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Headers</th>
<th>Production</th>
<th>Test</th>
<th>Water Inj.</th>
<th>Gas Lift</th>
<th>Chemical</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Headers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Size</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Hubs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Piggable</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Iso. Valve</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hub</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Materials</th>
<th>Header Piping</th>
<th>Branch Valves</th>
<th>Branch Piping</th>
<th>Load-bearing Structure</th>
<th>Header Valves</th>
<th>Secondary Structural Steel</th>
<th>Hub Connection</th>
<th>Insulating Materials</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Pigging</th>
<th>Required</th>
<th>Pig Isolation Valve (Qty)</th>
<th>Removable Pigging Loop</th>
<th>Pig Isolation Valve Style</th>
<th>Min. Bend Radius</th>
<th>Pig Isolation Valve Actuator</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Branches</th>
<th>Production</th>
<th>Test</th>
<th>Water Inj.</th>
<th>Gas Lift</th>
<th>Chemical</th>
</tr>
</thead>
<tbody>
<tr>
<td>No. of Branches</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Size</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Valve Style</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Valves/Branch</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Double Block Valve</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hub</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Control System</th>
<th>Type</th>
<th>Tubing Size</th>
<th>No. of SCMs</th>
<th>Tubing Material</th>
<th>Low Pressure Operating Pressure</th>
<th>Connection Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Pressure Operating Pressure</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>---------------------------------</td>
<td>---</td>
<td>---</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sensors</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. for Pressure/Temperature</td>
<td>Sand Detector</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Pig Detectors</td>
<td>Erosion/Corrosoion Monitor</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Testing Requirements</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Valves</td>
<td>Manifold Function Test</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manifold Hydro Test</td>
<td>Pad Eye Lift Test</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manifold Gas Test</td>
<td>Control System Test</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CP Continuity</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chemical Injection</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Different Chemicals</td>
<td>Tube Size</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Injection Points</td>
<td>Tube Material</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Processing Equipment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Pressure Vessels</td>
<td>Rotating Equipment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Bibliography


[2] API RP 2GEO, *Geotechnical and Foundation Design Considerations*


[10] API RP 17H, *Recommended Practice for Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems*


[12] API RP 17Q, *Recommended Practice on Subsea Equipment Qualification*


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


[20] ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*

[22] ASME, *Boiler and Pressure Vessel Code, Section II: Materials; Part C: Specifications for Welding Rods, Electrodes and Filler Metals*

[23] ASME, *Boiler and Pressure Vessel Code, Section V: Nondestructive Examination*


[33] ASTM A578/A578M-07, *Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications*

[34] ASTM A694/A694M, *Standard Specification for Carbon and Alloy Steel Forgings for Pipe Flanges, Fittings, Valves, and Parts for High-Pressure Transmission Service*


[38] ASTM A815/A815M, *Standard Specification for Wrought Ferritic, Ferritic/Austenitic, and Martensitic Stainless Steel Piping Fittings*


[40] ASTM A928/A928M, *Standard Specification for Ferritic/Austenitic (Duplex) Stainless Steel Pipe Electric Fusion Welded with Addition of Filler Metal*


[47] DNVGL-ST-F101, *Submarine Pipeline Systems*

[48] DNVGL-RP-F112, *Duplex Stainless Steel—Design Against Hydrogen Induced Stress Cracking*


[50] DNVGL-RP-B401, *Cathodic Protection Design*

[51] DNVGL-RP-F111, *Interference between Trawl Gear and Pipelines*


[53] EN 970, *Non-destructive examination of fusion welds - Visual examination*

[54] EN 10204, *Metallic products - Types of inspection documents*

[55] EN 10216-3, *Seamless steel tubes for pressure purposes - Technical delivery conditions - Part 3: Alloy fine grain steel tubes*

[56] EN 10216-5, *Seamless steel tubes for pressure purposes - Technical delivery conditions - Part 5: Stainless steel tubes*

[57] EN 10217-3, *Welded steel tubes for pressure purposes - Technical delivery conditions - Part 3: Alloy fine grain steel tubes*

[58] EN 10217-7, *Welded steel tubes for pressure purposes - Technical delivery conditions - Part 7: Stainless steel tubes*

[59] EN 10222-4, *Steel forgings for pressure purposes - Part 4: Weldable fine grain steels with high proof strength*

[60] EN 10222-5, *Steel forgings for pressure purposes - Part 5: Martensitic, austenitic and austenitic-ferritic stainless steels*

[61] EN 10228-2, *Non-destructive testing of steel forgings - Part 2: Penetrant testing*


[63] EN 10253-1, *Butt-welding pipe fittings - Part 1: Wrought carbon steel for general use and without specific inspection requirements*

[64] ISO 9001:2015, *Quality management systems—Requirements*

[66] ISO/IEC 17020, *Conformity Assessment—Requirements for the Operation of Various Types of Bodies Performing Inspection*


[68] ISO 19900, *Petroleum and Natural Gas Industries—General Requirements for Offshore Structures*

[69] NACE MR0175/ISO 15156, *Petroleum and Natural Gas Industries—Materials for Use in H₂S-containing Environments in Oil and Gas Production*

[70] NACE SP0176, *Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated with Petroleum Production*


[73] ASME B16.9, *Factory-Made Wrought Buttwelding Fittings*
