Design and Operation of Subsea Production Systems—Subsea Structures and Manifolds

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

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ISO 13628-15 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13628 consists of the following parts, under the general title *Petroleum and natural gas industries — Design and operation of subsea production systems*:

— *Part 1: General requirements and recommendations*

— *Part 2: Unbonded flexible pipe systems for subsea and marine applications*

— *Part 3: Through flowline (TFL) systems*

— *Part 4: Subsea wellhead and tree equipment*

— *Part 5: Subsea umbilicals*

— *Part 6: Subsea production control systems*

— *Part 7: Completion/workover riser systems*

— *Part 8: Remotely operated tools and interfaces on subsea production systems*

— *Part 9: Remotely Operated Tool (ROT) intervention systems*

— *Part 10: Specification for bonded flexible pipe*

— *Part 11: Flexible pipe systems for subsea and marine applications*

— *Part 15: Subsea structures and manifolds*

A Part 12, dealing with dynamic production risers, a Part 14, dealing with high-integrity pressure protection systems (HIPPS), a Part 16, dealing with specification for flexible pipe ancillary equipment, and a Part 17, dealing with recommended practice for flexible pipe ancillary equipment, are under preparation.

Petroleum and natural gas industries — Design and operation of subsea production systems —

Part 15: Subsea structures and manifolds

1 Scope

This part of ISO 13628 addresses recommendations for subsea structures and manifolds, within the frameworks set forth by recognized and accepted industry specifications and standards. As such, it does not supersede or eliminate any requirement imposed by any other industry specification.

This part of ISO 13628 covers subsea manifolds and templates utilized for pressure control in both subsea production of oil and gas, and subsea injection services. See Figure 1 for an example of such a subsea system.

Equipment within the scope of this part of ISO 13628 is listed below:

a) the following structural components and piping systems of subsea production systems:

— production and injection manifolds,

— modular and integrated single satellite and multiwell templates,

— subsea processing and subsea boosting stations,

— flowline riser bases and export riser bases (FRB, ERB),

— pipeline end manifolds (PLEM),

— pipeline end terminations (PLET),

— T- and Y-connection,

— subsea isolation valve (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.

The following components and their applications are outside the scope of this part of ISO 13628:

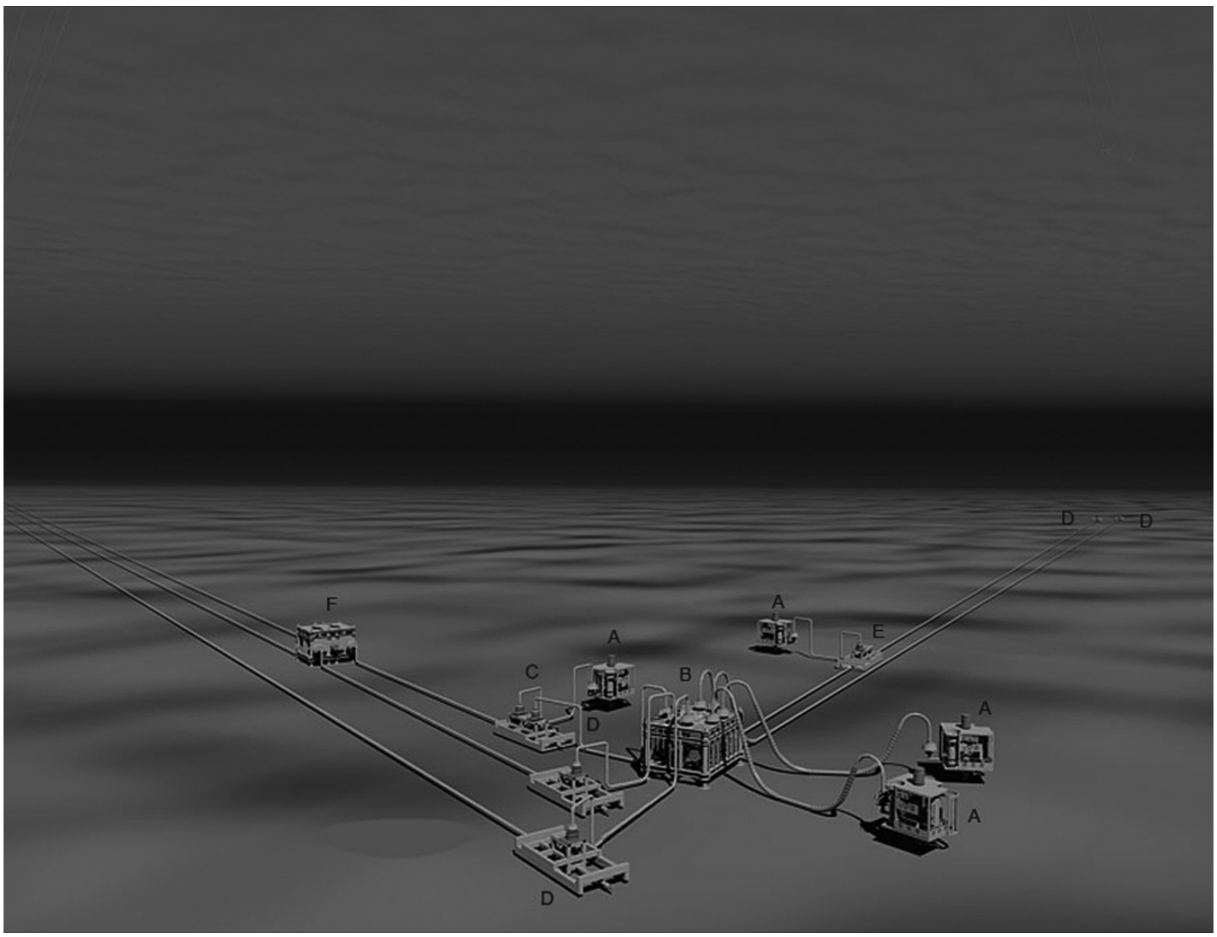
— pipeline and manifold valves;

— flowline and tie-in connectors;

— choke valves;

— production control systems.

NOTE General information regarding these topics can be found in additional publications, such as ISO 13628-1 and API Spec 2C.



Key

A tree

B cluster manifold

C PLEM

D PLET

E inline tee

F multi-phase pump skid

Figure 1 — Example of some typical subsea structures

2 Normative references

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

ISO 3183, *Petroleum and natural gas industries — Steel pipe for pipeline transportation systems*

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 10423, *Petroleum and natural gas industries — Drilling and production equipment — Wellhead and christmas tree equipment*

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

ISO 13628-1:2005, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 1: General requirements and recommendations*

ISO 13628-1:2005/Amd 1:2010, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 1: General requirements and recommendations — Amendment 1: Revised Clause 6*

ISO 13628-4, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 4: Subsea wellhead and tree equipment*

ISO 13628-8, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 8: Remotely operated tools and interfaces on subsea production systems*

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

ISO 15156 (all parts), *Petroleum and natural gas industries — Materials for use in* H_2S*-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 473, *Non-destructive testing — Qualification and certification of NDT personnel — General principles*

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*

ASME B31.3, *Process Piping*

ASME V, 2007, Boiler and Pressure Vessel Code (BPVC), Section V, *Nondestructive Examination*

ASME VIII, 2007, Boiler and Pressure Vessel Code (BPVC), Section VIII, *Rules for Construction of Pressure Vessels*, Div. 1

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

ASNT SNT-TC-1A, *Recommended Practice No. SNT-TC-1A, Personnel qualification and certification in nondestructive testing*

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

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

ASTM G48, *Standard Test Methods for Pitting and Crevice Corrosion Resistance of Stainless Steels and Related Alloys by Use of Ferric Chloride Solution*

NS 477, *Welding — Rules for qualification of welding inspectors*

3 Terms, abbreviated terms, and definitions

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

3.1 Terms and definitions

3.1.1
carbon steel
full range of carbon, carbon-manganese and low-alloy steels used in the construction of conventional oilfield equipment

3.1.2
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.

3.1.3
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.

3.1.4
inline tee
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.

3.1.5
low-alloy steel
steel containing at least 1 % and less than 5 % of elements deliberately added for the purpose of modifying properties

3.1.6
manifold
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, connectors for pipeline and tree interfaces, chokes for flow control and TFL diverters. The manifold system can also 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.

3.1.6.1
cluster manifold
structure used to support a manifold for produced or injected fluids

NOTE There are no wells on a cluster manifold.

3.1.7
mudmat
typically a shallow structure used to support a subsea structure by distributing the load to the seabed via a structural plate or shallow skirt

3.1.8
pipeline end manifold
PLEM
system of headers, piping and valves 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

3.1.9
pipeline end termination
PLET
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.

3.1.10
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

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):

$$f_{\text{PREN}} = w_{\text{Cr}} + 3{,}3w_{\text{Mo}} + 16w_{\text{N}} \qquad (1)$$

$$f_{\text{PREN}} = w_{\text{Cr}} + 3{,}3(w_{\text{Mo}} + 0{,}5w_{\text{W}}) + 16w_{\text{N}} \quad (2)$$

where

w_{Cr} is the mass fraction of chromium in the alloy, expressed as a percentage of the total composition;

w_{Mo} is the mass fraction of molybdenum in the alloy, expressed as a percentage of the total composition;

w_{W} is the mass fraction of tungsten in the alloy, expressed as a percentage of the total composition;

w_{N} is the mass fraction of nitrogen in the alloy, expressed as a percentage of the total composition.

3.1.11
protection structure
independent structure that protects subsea equipment against damage from dropped objects, fishing gear and other relevant accidental loads

3.1.12
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.

3.1.13
sealine
subsea flowline

3.1.14
sour service
service in H_2S-containing fluids

NOTE In this part of ISO 13628, “sour service” refers to conditions where the H_2S content is such that restrictions as specified in ISO 15156 (all parts) or NACE MR 0175 apply.

3.1.15
suction pile
typically a tall steel cylindrical structure, open at the bottom and normally closed at the top, with or without an internal stiffener system and used to support subsea structures

NOTE 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.

3.1.16
sweet service
service in H_2S-free fluids

3.1.17
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), and 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.

3.1.17.1
modular template
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.

3.1.17.2
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.

3.1.18
type 316
austenitic stainless steel alloy

EXAMPLES UNS S31600/S31603.

3.1.19
type 6Mo
austenitic stainless steel alloy having PREN $\geq$ 40 mass fraction and Mo alloying $\geq$ 6,0 % mass fraction, and nickel alloy having a Mo content in the range 6 % mass fraction to 8 % mass fraction

3.1.20
type 22Cr duplex
ferritic/austenitic stainless steel alloy with 30 $<$ PREN $\leq$ 40 and Mo $>$ 1,5 % mass fraction

EXAMPLES UNS S31803 and S32205 steels.

3.1.21
type 25Cr duplex
ferritic/austenitic stainless steel alloys with 40 $\leq$ PREN $<$ 45

EXAMPLES S32750 and UNS S32760 steels.

3.1.22
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.

3.1.23
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.

3.2 Abbreviated terms

ACCP ASNT Central Certification Program

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society for Testing and Materials

ASNT American Society of Nondestructive Testing

AWS American Welding Society

BOP blowout preventer

BPVC Boiler and Pressure Vessel Code

CE_{IIW} carbon equivalent, based on the International Institute of Welding equation

CE_{Pcm} carbon equivalent, based on the chemical portion of the Ito-Bessyo carbon equivalent equation

CRA corrosion-resistant alloy

DAC distance amplitude curve

DNV Det Norske Veritas

EWF European Federation for Welding, Joining and Cutting

EN European Norm

FBH flat-bottom hole

FIV flow-induced vibration

FL fusion line

GMAW gas metal arc welding

GTAW gas tungsten arc welding

HAZ heat-affected zone

HAZOP hazard and operability analysis

H_D diffusible hydrogen, expressed as ml/100 g deposited metal

HIP hot isostatic pressed

IDS interface data sheet

IIW International Institute of Welding

IWE	International Welding Engineer
LP	liquid penetrant
MAG	metal-active gas
MDT	minimum design temperature
MEG	monoethylene glycol
MIG	metal-inert gas
NDT	non-destructive testing
NORSOK	Norsk Sokkels
NS	Standards Norway
O-ROV	observation/inspection-class remote operated vehicle
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 structures
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
W-ROV	work-class remotely operated vehicle
XT	christmas tree

4 Manifold and template functional considerations

4.1 General

4.1.1 Manifold system design typically fulfils the following functions:

a) gather production or distribute water or gas from or to multiple production, water, or gas injection wells;

b) direct flow of fluids through manifold headers;

c) contain one or more headers;

d) allow isolation of individual well slots from header;

e) incorporate flowline connections between manifolds and appropriate flowlines and/or test lines;

f) allow continuity of pigging of flowline system;

g) typically provide termination points for flowlines.

h) allow for product flow into or out of a flowline system through subsea tree tie-ins by remotely or manually functioning valves.

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

— maximum dimensions and target weight;

— pressure and temperature ratings;

— equipment interfaces;

— process and instrumentation diagrams (P&IDs);

— materials requirements;

— water depth;

— design life;

— geotechnical and geophysical data;

— metocean data;

— dropped-objects protection requirements;

— over-trawling requirements including special fishing gear loads (snag loads) for the geographic region.

4.1.3 All equipment should

— comply with the latest revision of end user's product requirements;

— be designed to the pressure and temperature ratings;

— be compatible (dimensions and mass) with handling and installation capabilities of the installation vessel;

— be functional and fit for purpose for specified operating environment.

Subsea production or injection manifolds should be located in proximity to production or injection wells of field development.

4.1.4 Material selection for individual components, including all seal materials, should meet the requirements of ISO 13628-1 concerning

— production, injection fluids, and completion fluids for wetted areas;

— exposure to chemical injection and service fluids. This applies equally to seal materials.

NOTE For the purposes of this provision, ANSI/API RP 17A is equivalent to ISO 13628-1.

4.2 System requirements

The flexibility to meet various production scenarios (e.g. “retrofit” installation of pumps, separators and other modules) and possible future expansions should be considered. For each design, potential future requirements should be addressed, and it should be clearly explained how the manifold system is prepared for implementing the identified functions.

The following considerations related to structures and modules should be addressed:

— transportation, lifting, installation (inclusive of potential levelling), abandonment;

— flowline pull-in, connection and 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 MEG injection for hydrate control;

— thermal performance;

— annulus bleed operations;

- well testing;
- barrier testing;
- planned and emergency shutdowns of wells and manifold;
- pressurization and depressurization of piping system;
- pigging of flowlines, such as for gauge and cleaning operations;
- ROV/ROT inspections and interventions, inclusive of module replacement;
- 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;
- fluid flow regimes (slugging).

4.3 System Interfaces

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

- internal and external pressure;
- simultaneous expansion and contraction on the same structure, whether the structure is an XT, a module, a template or a manifold;
- zero external leakage and seawater ingress;
- tolerance loops for interface make-up;
- internal and external temperature variations;
- structure for protection against dropped objects and fishing gear;
- impact from dropped objects and fishing gear;

- short- and long-term structure settlement;
- marine growth;
- corrosion and erosion;
- scaling on subsea mate-able surfaces;
- potential formation of hydrate;
- installation loads;
- pull-in and connection loads;
- projected product lifespan;
- serviceability;
- protection from ROV impact loads;
- subsea controls connection systems;
- chemical injection requirements.

4.3.2 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 and well jumpers, controls flying leads.

4.4 Cluster manifold requirements

4.4.1 General

The cluster manifold consists of a framework that supports other equipment, such as piping, pipeline pull-in and connection equipment, and protective framing. The cluster manifold commingles flow from a number of subsea wells into one or more headers. The cluster manifold provides a foundation to sufficiently transfer design loads into the seabed. The cluster manifold may include the following components; see Figure 2:

- subsea control module;
- subsea distribution unit;
- electrical distribution unit.

4.4.2 Alignment

The cluster manifold should provide alignment capability for proper physical interfaces with other subsystems, such as connectors and foundations.

4.4.3 Guidance system

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

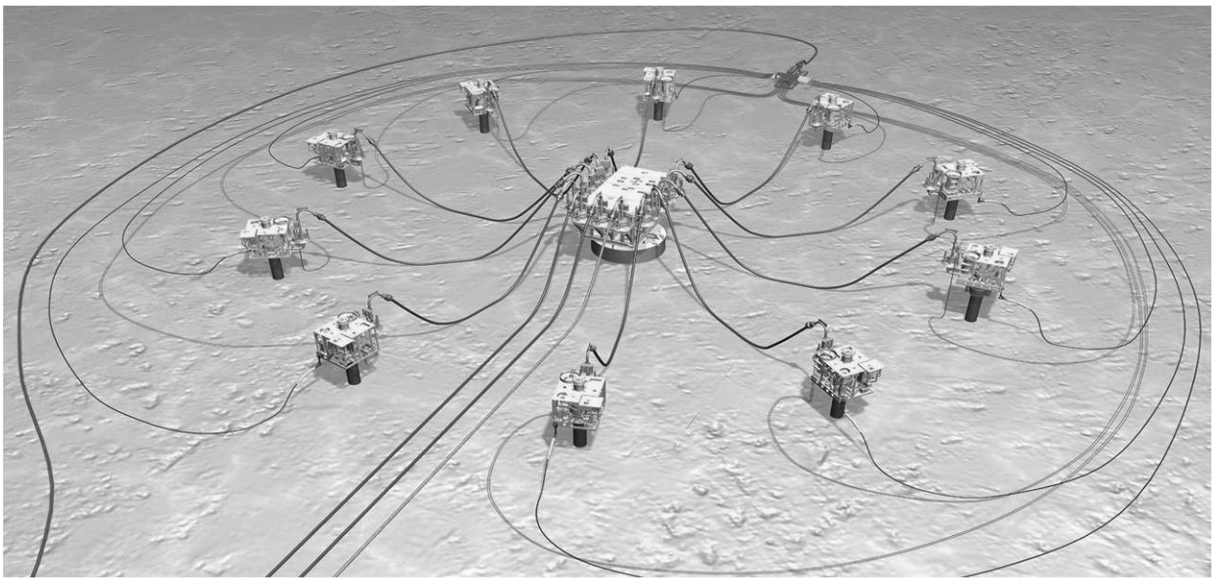


Figure 2 — Typical cluster manifold

4.5 Template system requirements

4.5.1 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 (template and protective framing are often built as one integrated structure). The template should provide a foundation to sufficiently transfer design loads into the seabed. See Figure 3.

4.5.2 Drilling and completion interface

If wells will be drilled through the template, it should provide a guide 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, the template should provide proper mechanical positioning and alignment for the trees and sufficient clearance for running operations.

4.5.3 Alignment

The template should provide alignment capability for proper physical interfaces among subsystems, such as wellhead/tree, tree/manifold and manifold/flowlines.

4.5.4 Guidance system

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 guideline-less methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items.

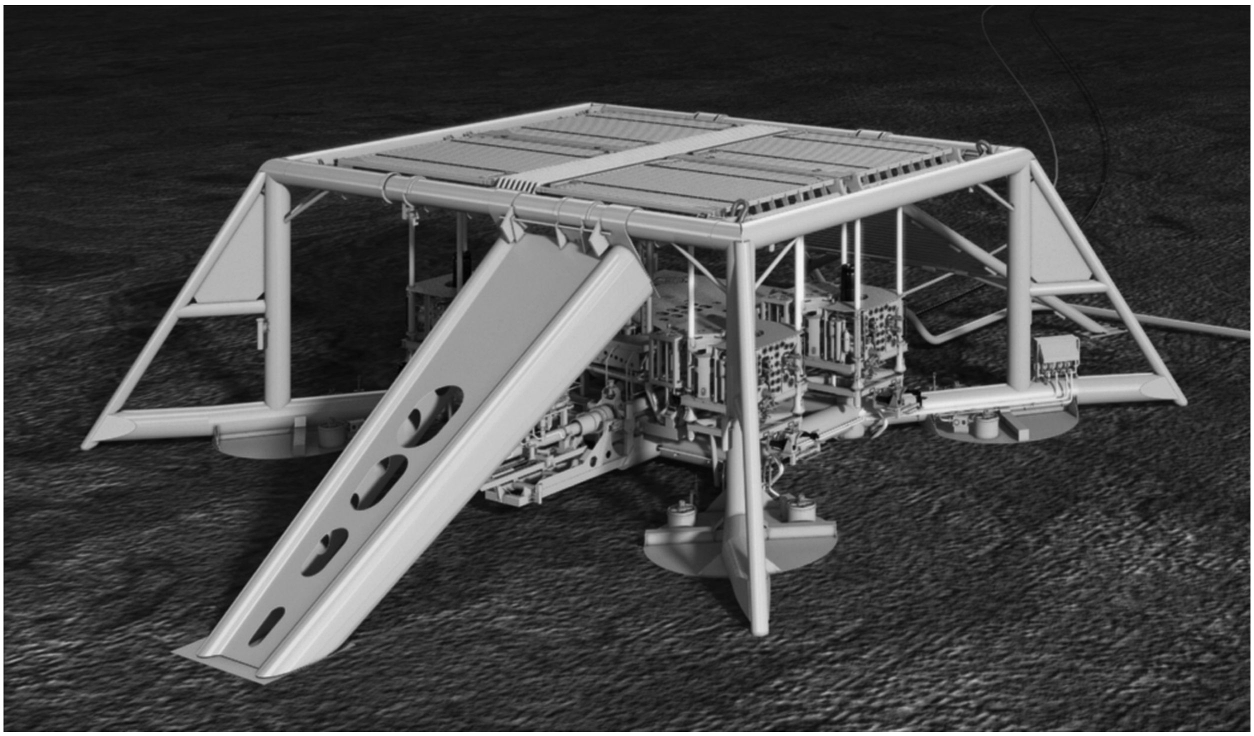


Figure 3 — Typical template system

5 Design considerations

5.1 System design

5.1.1 Number of wells

If wells are incorporated into the template or cluster manifold, the number of wells will vary depending on the site-specific application, and will greatly influence template size and manifold design. The addition of spare well slots should be considered for contingencies such as changes in reservoir depletion plan, dry holes, drilling problems and other unforeseen production requirements.

5.1.2 Well spacing

Well spacing may be governed by the type and size of drilling and production equipment used, the functional requirements of the manifold, and subsequent maintenance and inspection requirements. Consideration should be given to providing space for such items as flowline and wellhead connections and their running tools, and adjacent BOP and production tree clearances. Access should also be provided for inspection and maintenance tools.

5.1.3 Maintenance

Maintenance is a key factor in system design, and the maintenance approach should be considered early in the design of a template/manifold system.

Some factors to consider are

- diver-assisted or remote maintenance methods;
- the requirement that components be retrievable;
- clear access space for divers, ROVs or other maintenance 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

See ISO 13628-1:2005, Annex J for additional information on barrier philosophy.

Permanent isolation requirements against external leakage for pressurized systems should be provided by double, pressure-containing barriers in all applicable external connection points, and in particular

a) un-utilized end connections or prior to hook-up of XT in combination with pressurized manifold piping:

   two pressure barriers are required, one isolation valve and one pressure plug or cap or two isolation valves;

b) prior to hook-up of XT in combination with non-pressurized manifold piping:

   one pressure barrier, in combination with a protection device that retains inhibited fluids to protect the environmental side of the isolation valve in order to avoid seawater-imposed corrosion of and fouling on the valve, is required; the pressure barrier can be provided by the manifold branch valve, while the protection device can be provided by a pressure cap on the hub towards the XT;

c) for diver-mated connections:

   It is recommended to have two pressure barriers with a block-and-bleed function.

For temporary, time-limited operations, it can be acceptable to use only one valve for isolating a manifold pressurized towards the environment. The valve should be checked to ensure it is holding pressure prior to releasing the outboard barrier, in combination with an overall safety assessment for the activity.

The closure element of a valve (gate, ball) shall not be permanently exposed to the environment, i.e. an inhibited volume is required on the environmental side of the isolation valve in order to avoid seawater-imposed corrosion of and fouling on the valve.

It is recommended that all hubs be provided with high-pressure caps at delivery. Generally, they are required for testing prior to installation and operation.

NOTE For the purposes of these provisions, ANSI/API RP 17A is equivalent to ISO 13628-1.

5.1.5 Safety

It is important that safety risks be considered 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 ISO 13628-1.

NOTE For the purposes of this provision, ANSI/API RP 17A is equivalent to ISO 13628-1.

5.1.6 External corrosion protection design

External corrosion control can be provided by appropriate materials selection, coating systems and cathodic protection. A corrosion control programme should be developed during the design phase and incorporated into the design of the system.

5.1.7 Templates

5.1.7.1 General

The template design may be based on an integrated or modular system layout. Selection of the template concept should consider the following parameters:

- 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.

5.1.7.2 Integrated template

An integrated template concept may include bottom structure, manifold and protection structure in one unit, depending on the application and requirements for protection against fishing gear and dropped objects.

5.1.7.3 Modular template

A modular template concept may consist of separately installable/replaceable modules and structures. If applicable, an additional requirement for moon-pool installable size may be applied.

The manifold can be designed for installation both together with the template and as a separate module.

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, 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), abnormal environmental loads (earthquake), etc. The data sheet in Annex A may be used to define applicable loads.

5.2.1.2 Snag loads

Design of subsea structures for protection against trawl loads and dropped objects should be based on the requirements in ISO 13628-1, and NORSOK U-001 as a basis.

However, due to the fact that 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 shall do field-specific examination in the early phase in order to establish any requirement for 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 in kilonewtons,

   2) trawl equipment pull-over, expressed in kilonewtons,

   3) trawl equipment impact, expressed in kilojoules.

Special care should be taken at small, closed corners on the protection structures with respect to the risk of snagging. Over-trawlability tests should be performed for new structure designs. The scope of these tests should be mutually agreed upon with the end user in order to obtain a realistic test.

For equipment in depths below 750 m, normally accepted as guideline-less, 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, it is necessary that the equipment be protected only against dropped objects.

5.2.2 Thermal effects

Equipment designs should be capable of functioning throughout the temperature range for which the product is rated, including allowance for thermal expansion of conductor/wellhead housings. The end user is responsible for specifying or approving this temperature requirement.

5.2.3 Templates

If a template structure is selected and drilling loads can be transferred into the structure, the structure should be able to accommodate all relevant loads addressed in ISO 13628-1, including

— drilling 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).

NOTE For the purposes of these provisions, ANSI/API RP 17A is equivalent to ISO 13628-1.

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

5.3 Piping design

5.3.1 General requirements

5.3.1.1 Manifold systems 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; the manifold typically provides sufficient flexibility to make and break these connections;

— be designed to account for hydrostatic loads due to external pressure;

— have appropriate valve and line-bore dimensions to allow pigging of flowlines and appropriate manifold headers;

— provide for the connection to the tree, if the template includes wells;

— 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;

— provide for mounting trawling equipment.

5.3.1.2 Recommendations for the piping system include the following.

— The piping system should include a length of straight pipe downstream of the choke valve, 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.

— 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.

— Fluid velocities should be considered in sizing pipes to reduce pressure drops and control flow-induced erosion.

— An internal erosion and corrosion allowance should be considered in determining required wall thickness.

— Access for NDT activities and insulation application during fabrication should be considered.

5.3.2 Applicable piping codes

Codes used in 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 or API Spec 1111. One or more of these codes can be utilized 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 considered.

5.3.3 Pigging

When pigging with gauge plates for internal diameter verification of the manifold header piping, the recommended acceptance criterion is 95 % of nominal internal diameter (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, should consider ID variations, fitting spacing and special branch connections.

5.3.4 Erosion

Critical flow velocity introducing erosion in the piping can be calculated as given in ANSI/API RP 14E. 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 utilized to mitigate erosion effects. Areas may be provided for measurements by ROV of 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 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. Additional general flow assurance considerations can be found in ISO 13628-1:2005, Annex I. Special considerations may be given to gas-producing manifolds regarding distribution of MEG, etc., related to "uphill/downhill" and "dead legs" in the actual piping system.

5.4 Structural design

5.4.1 General

5.4.1.1 Subsea structures should be designed as given in the relevant standards such as ISO 19900, ISO 19902 and API RP 2A. 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).

5.4.1.2 The two approaches from ISO 19902, for example, provide detailed guidance for design classification and materials selection of jacket structures and can be correlated to manifold structures.

NOTE ISO 19902:2007, Annex C, describes the material class (MC) approach and Annex D, the design class (DC) approach. With respect to selection of material standards and grades, the MC approach specify 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.

5.4.1.3 The material selection process shall consider restrictions on the following:

a) general:

— chemical composition (carbon equivalency), for weldability,

— Charpy V-Notch (CVN), for toughness,

— SMYS due to material geometry (thickness);

b) plates/pad eyes and primary structural members, for which the following minimum material properties are typically recommended:

— through thickness tensile testing, "Z" direction, as given in ASTM A770/A770M, 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 II, 100 % scan,

— Charpy requirements: temperature from the CVN test (TCVN) 41 Nm average/34 Nm minimum at –23 °C (30 ft/lb average/25 ft/lb minimum at –10 °F) supplements;

c) structural shapes

- Charpy requirements: temperature from the CVN test (TCVN) 41 Nm average/34 Nm minimum at –23 °C (30 ft/lb average/25 ft/lb minimum at –10 °F) supplements.

Welding requirements and qualifications should be based on acceptable standards, such as ASME BPVC Section IX, AWS D1.1 and ISO 15614-1.

5.4.2 Bottom frame/guide base/support structure

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

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

- soil conditions and axial stiffness of the well system;
- structural design and stiffness of bottom frame against vertical deflection;
- 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 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.

The structure should allow onshore assembly and testing of equipment supported by the structure.

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 neighbouring subsea tree.

5.4.3 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.

— Water filling of tubular volumes prior to installation offshore should be avoided if practical. If water filling of the tubular volumes is required, it should be carried out in an effective and safe manner. Where possible, the filling should be conducted from deck level using a quick connector.

— ROV access should be provided for inspection and manipulative tasks, such as valve operations on the manifold and XT, without the need for opening the hatches/covers.

— The arrangement of the roof hatches should not prevent W-ROV 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 W-ROV 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 neighbouring 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 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).

— 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.

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

— 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 by ROV when the cover is either fully open or fully closed and 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 General

The foundation design should be selected based on site-specific soil conditions. Foundation configurations that can be utilized include mudmats, skirts, driven piles, suction piles, conductors, or combinations of these. It is important to evaluate subsurface obstacles such as boulders, as well as drilling aspects such as mud pressure, mudflow, washout, etc., as part of the selection criteria.

In order to design the foundation and levelling system, the following should be considered:

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

— suction loads due to repositioning or levelling;

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

— for foundation and skirt systems, arrangements 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;

— consideration of skirt-system facilities for suction and pumping for final penetration, levelling and breaking out prior to removal; the suction and pump systems should be operated in accordance with the selected intervention strategy;

— settlement of the structures (installation and lifetime);

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

5.5.2 Requirements

5.5.2.1 General

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 considered 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 considered 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 into the seabed. Contingency solutions include adding weight to assist penetration, or filling grouting into the skirt compartment. In the latter case, a 50 mm (2 in) injection point and a 50 mm (2 in) vent is usually required on top of the skirt foundation. A last-resort contingency can be to relocate the structure within a predefined target area.

5.5.2.2 Suction piles

A typical analysis for suction piles includes the penetration resistance, the under-pressure required to allow embedment, and the critical pressure at which the soil plug fails.

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 under-pressure is the under-pressure that causes a general reverse bearing failure at the pile tip and large soil heave within the pile. The recommended allowable under-pressure is defined as the maximum under-pressure that should be applied to the foundation divided by a safety factor, which is typically a minimum of 1,5. The allowable under-pressure 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”.

Suction piles are not appropriate for gravel seabeds, as ground-water flow limits suction. Considerations for suction piles include

a) design considerations:

   — closed versus open top,

— inclusion of internal ring stiffeners which affect skin friction,

— installation tolerances (e.g. tilt, orientation),

— distance between installation locations to avoid mobilizing disturbed soil;

b) fabrication considerations:

— pile diameter,

— wall thickness,

— pile length,

— out-of-roundness,

— circularity,

— straightness.

5.5.2.3 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 RP 2A. The recommended criteria in API RP 2A should be applied for the design of driven piles.

The design of driven piles should consider 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.

5.5.2.4 Skirted structures

Design of skirted structures should consider penetration resistance and horizontal and vertical load component capacities, and ensure self-righting behaviour during installation.

For suction skirt foundations, the skirts should, with the exception of the skirt marking, 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.

5.5.2.5 Non-skirted structures

A non-skirted structure should provide enough surface area to support the subsea structure, interfacing systems and design loads. Corners of the structure should penetrate the seabed to mitigate snagging hazards.

Settling and suction forces during pullout can be greater for non-skirted structures than for skirted structures, and should be accounted for in the design.

5.5.3 Levelling

Generally, subsea systems require that the equipment (templates, manifolds, etc.) be reasonably level in their final position for proper interface and mating of the various components and subsystems. Typical levelling methods include one- and two-way slips between piles and pile guides, jacking systems at the template corners, and the active-suction method. A means of level indication may be included on the structure.

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

The levelling system should be able to adjust the inclination within a tolerance specified by the contractor, accompanied with documented feasibility of all relevant operations. It should be possible to level the template within 0,5°. For other structures such as cluster manifolds and PLEMs, the 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.

NOTE The final inclination of structures with mudmat foundations which typically do not incorporated a leveling system can be considered. 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. Typical solutions are to adjust the inclination of the mudmat relative to the structure or survey and level the landing area of the mudmat.

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 levelling 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. Consideration should be given to avoid visibility problems during operation.

A single independent valve should be included on the levelling 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 piping.

Any requirement for levelling of the structure after the first conductor hang-off should be considered and accounted for if required.

5.5.4 Grouting system

A stab/receptacle system for contingency grouting of suction piles should be provided. It is recommended that the receptacle and stab (a minimum of two stabs) be provided by the contractor supplying the structure. Considerations should be given to applicable loads from the grouting riser/hose to the connector.

5.6 Components

5.6.1 General

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 recommended practices. These components should be designed, built, tested and qualified according to the applicable specifications, codes and recommended practices. Table 1 provides a list of applicable industry standards.

Table 1 — Industry standards for manifold components

Component	Industry specification
Production/injection valves	ISO 10423 (ANSI/API Spec 6A) ISO 13628-4 (API Spec 17D) ISO 14313 (API Spec 6D)
Chokes	ISO 10423 (ANSI/API Spec 6A) ISO 13628-4 (API Spec 17D)
Control components	ISO 13628-6 (ANSI/API RP 17F)
End connectors	ISO 13628-4 (API Spec 17D)
Flanges	ISO 10423 (ANSI/API Spec 6A) ISO 13628-4 (API Spec 17D)

5.6.2 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 approved by the end user.

5.6.3 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, and injected chemicals.

The general design characteristics for these fluids are supplied by the end user, and include

- pour point;
- pressure;
- temperature;
- chemical composition;
- viscosity;
- gas/oil/water ratio;
- sand/paraffin/hydrates;
- corrosivity.

6 Verification and validation of design

6.1 Design verification

6.1.1 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 Clause 4;

c) performing design reviews according to 6.1.3;

d) hydrostatic testing.

6.1.2 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 centres-of-mass for system components;
- HAZOP and SAFOP reports;
- operating and maintenance manuals:
    - storing and preservation procedures,
    - planned normal operating modes,
    - installation/retrieval procedures,
    - spare part lists,

  - loadout procedures,
  - commissioning/hook-up requirements and limitations,
  - decommissioning requirements and limitations;
- manufacturing data book:
  - as-built/as-installed documentation,
  - testing reports and records.

6.1.3 Design reviews

Design review of the manifold system and components should be performed according to the design plan. The design plan should be developed as 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 customer 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 considerations;
- ease of maintenance and operation;
- installation issues;
- retrieval issues;
- intervention analysis, including ROV accessibility.

6.1.4 Factory acceptance testing

6.1.4.1 A comprehensive acceptance test programme 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 failure should be repaired and analysed to find the reason for the failure and/or result in a review of the calculated reliability of the system to determine whether 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.

6.1.4.2 A typical format for a subsea equipment 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.

6.1.4.3 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 or 1 h (recommended) if not specified,

  — includes seal testing of end closures.

6.2 Design validation

6.2.1 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.

6.2.2 Qualification testing

Individual components, such as valves, actuators and fitting and control system components, should be qualified independently of the manifold/template system. The manifold/template system should be subjected to a preapproved qualification test that is defined by the operational limits.

6.2.3 System integration testing

While the total system integration test is outside the scope of this part of ISO 13628, the manifold system should be part of the system integration test. The provisions of this subclause are provided as a guideline for typical testing. The different 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;

— pull-in and connection of umbilical (hydraulic/chemical lines and electrical connections) and flowlines;

— tolerance check of manifold system after reinstallation;

— pigging operations.

It is important to functionally test all manual-override functions in connection with the above tests. The purpose of the intervention test is to verify the interfaces and the functions of the ROT system, ROV 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.

6.3 Other comments

A manifold system and/or components

— where practicable, should be manufactured using field-proven and qualified materials, components and processes;

— are subject to dimensional control to verify conformance with design drawings; acceptable deviations should be recorded;

— should be subjected to testing to simulate actual field conditions, where practical;

— should be preserved and packed as required prior to delivery.

It should be ensured that the valves do not experience excessive differential pressure across the main closure element or between the conduit and the cavity during pressure testing. This can be ensured by having the valves in half-open position.

7 Materials and fabrication requirements to piping systems

7.1 General

This clause is based on the use of ASME B31.8 as the governing design code for the piping systems, and gives additional requirements to that code. For installation where a design code different from ASME B31.8 applies, the requirement of that different code shall govern unless this is less stringent than required by this clause.

All materials selections shall be in accordance with the requirements given in ISO 13628-1.

NOTE For the purposes of this provision, ANSI/API RP 17A is equivalent to ISO 13628-1.

Material requirements for valves and connectors should meet the requirements of ISO 10423.

The pressure-containing parts of the manifold structure should be formed from carbon, low-alloy, stainless steel or nickel alloy as listed in 7.2 and 7.3.

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

All components, including fasteners, shall be delivered with a material certificate in accordance with ISO 10474 Type 3.1.B/EN 10204 3.1 or higher certification (e.g. 3.2 Certification) confirming all requirements of the relevant component standard and additional requirements of this part of ISO 13628.

All materials for pipe, forgings and fittings shall be manufactured and used in accordance with the listed product specifications of the design standard and this clause. Use of other product standards shall be agreed and approved by the end user.

All carbon and low-alloy steel shall be made by the basic oxygen or electric arc furnace methods, and shall be fully killed and made to fine grain practice. All carbon steels intended for cold deformation shall be nitrogen-stabilized, i.e. the Al/N ratio shall be less than 2/1.

The requirements in the remaining subclauses of this clause shall be in addition to or shall replace the corresponding requirements in the reference standards, as relevant.

7.2 Pipe and pipe fittings

The pipes and pipe fittings shall be manufactured either by a seamless process hot working steel 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 and fittings shall conform to an appropriate reference standard suitable for the purpose of the application, for example those listed in Table 2.

The delivery condition of pipes shall be in normalized, thermo-mechanically treated or quenched and tempered condition. All fittings shall be used in normalized, normalized and tempered, or quenched and tempered condition. Welded pipes should conform to the requirements of 7.11.

For welded pipes and fittings, the PQR/WPQR should be qualified in accordance with ISO 15614-1 or ASME BPVC IX, and comply with the base material requirements. All welding should be carried out by welders qualified in accordance with ISO 9606, ASME BPVC IX or EN 287-1 and EN 1418.

Table 2 — Reference standards for seamless and welded pipe and pipe fittings in carbon and low-alloy steel

Standard	Manufacturing process	Standard	Manufacturing process
ISO 3183 (ANSI/API Spec 5L) PSL 2	Seamless and welded pipe	ASTM A420/A420M	Seamless and welded fittings
ASTM A333/A333M	Seamless and welded pipe	ASTM A860/A860M	Seamless and welded fittings
EN 10216-3	Seamless pipe	—	—
EN 10217-3	Welded pipe	—	—

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

Table 3 — Reference standards for seamless and welded manifold pipe and pipe fittings in stainless steel alloy

Standard	Manufacturing process	Standard	Manufacturing process
ASTM A312/A312M	Seamless pipe	EN 10216-5	Seamless pipe
ASTM A358/A358M	Welded pipe	EN 10217-7	Welded pipe
ASTM A790/A790M	Seamless pipe	ASTM A403/A403M	Seamless and welded fittings
ASTM A928/A928M	Welded pipe	ASTM A815/A815M	Seamless and welded fittings
ASTM B705	Seamless and welded pipe	ASTM B366	Seamless and welded fittings

The following stainless steels and nickel alloys, solid or clad, are applicable to manifold piping (but this list does not exclude selection of other alloys or material grades):

— austenitic stainless steel, e.g. type 316 and 6Mo;

— duplex stainless steel, e.g. type 22Cr or 25Cr duplex;

— nickel-based alloys, e.g. N06625 and N08825.

All components in austenitic stainless steel grades and intended for welding shall have carbon content ≤ 0,03 % mass fraction or be stabilized by Nb or Ti alloying.

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.

7.3 Forged components

Forgings for pressurized components shall conform to an appropriate reference standard suitable for the purpose of the application, for example those listed in Table 4.

Table 4 — Material standards for forged pressure-containing components

Material type	ASTM standard	EN standard	ISO standard
Carbon or low-alloy steel	A182/A182M, A350/A350M, A508/A508M, A694/A694M, A707/A707M	10222-4	15590-3
Type 22/25Cr duplex	A182/A182M	10222-5	—
Austenitic stainless steel	A182/A182M	10222-5	—
Nickel alloys	B564	—	—

In addition to the requirement listed in Table 4, 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 hot isostatic pressed (HIP) process as given in ASTM A988/A988M is an acceptable alternative to forging.

7.4 Chemical composition and weldability

The material should have weldability suitable for all stages of component manufacture, fabrication and installation. Carbon and low-alloy steels intended for sour/non-sour service should have the limitations in sulfur content as specified in Table 5.

Table 5 — Limitations in sulfur content, S, in carbon and low-alloy steels

Type of product	Sulfur content S % mass fraction	
	Non-sour service	**Sour service**
Rolled plate products	$S \leq 0{,}015$	$S \leq 0{,}003$
Seamless pipe	$S \leq 0{,}015$	$S \leq 0{,}010$
Forged products	$S \leq 0{,}025$	$S \leq 0{,}025$

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.

The nitrogen content of UNS S31803 should be in the range 0,14 % to 0,2 % mass fraction.

The susceptibility of carbon and low-alloy steels to hydrogen cracking in the heat-affected zone shall be controlled by limiting the allowable value of the carbon equivalent of the steel material and/or performing post-weld heat treatment to meet the specified maximum hardness after welding.

7.5 Test sampling of base materials

7.5.1 General

The test sample for production testing should realistically reflect the properties in the finished product. The test samples should be taken in accordance with the relevant pipe, fitting or forged component standards listed in Tables 2 to 4.

7.5.2 Test sampling of forgings and hot isostatic pressed components

A test lot shall contain components of the same type, manufactured according to the same manufacturing method, from the same heat of steel and heat-treatment load.

The test sample should be selected from the component having the heaviest wall thickness within the lot.

The test sample should be taken from a sacrificial component or from a prolongation at one of the following positions:

— at a cross-section thickness, T, representing the area of the part with maximum stresses, e.g. the welding end, at mid-wall and at least T or 50 mm (2 in), whichever is more, from the end face;

— at the heaviest cross-section, T, of a product, at least $T/4$ below the surface and at least T or 100 mm (4 in), whichever is less, from any second heat-treated surface.

Separate test blocks, in accordance with requirements in ISO 10423 for qualification test coupons are acceptable if agreed with the end user.

For hot isostatic pressed (HIP) manufactured products, integral test blocks should be made. These should not be parted from the HIP component until after all heat treatment is completed.

All mechanical testing should be performed after final heat treatment of the product.

7.6 Mechanical and corrosion testing of base materials

7.6.1 General

All mechanical testing should be carried out in accordance with the applicable ISO, EN or ASTM standards referred to in the product standards listed in Tables 2 to 4.

7.6.2 Tensile testing

At least one (1) tensile test specimen should be tested per test lot.

The tensile test specimens should be taken in the longitudinal or transverse direction as defined by applicable product standards; see Tables 2 to 4.

7.6.3 Charpy V-notch impact requirements

All products in ferritic, ferritic-austenitic and martensitic steel should be impact-tested per test lot, for products with wall thickness 6,0 mm (0,25 in) or greater. One test shall consist of three (3) specimens. Full-size specimens should be used whenever possible. When sub-size specimens are used, the specimen width should not be less than 5,0 mm (0,20 in).

The impact test specimens should be taken in the direction transverse to the primary wrought direction, except for components whose dimensions prohibits the use of full-size transverse specimens.

The test temperature for components in carbon and low-alloy steel, and martensitic stainless steels with an integral weld end, should be the minimum design temperature minus 10 °C (18 °F), or lower. The test temperature for components not intended for welding should be the minimum design temperature, or lower.

Pipes, fittings and forged components in stainless steel types 22Cr and 25Cr duplex should be impact-tested at –46 °C (–50 °F) or at minimum design temperature minus 10 °C (18 °F), whichever is lower. If the minimum design temperature is above the specified test temperature, the test temperature may be increased to the MDT if agreed with the end user.

NOTE The impact test temperature specified above for duplex stainless steels is consistent with a standardized quality control test to ensure appropriate manufacturing and heat treatment processes.

Impact testing is not required of austenitic stainless steel or nickel-based alloys.

The minimum average absorbed energy from three (3) specimens shall be in accordance with Table 6 for pipes, fittings and forgings, including welding zone of welded products. In the heat-affected zone, the notch should be at 1 mm (0.04 in) to 2 mm (0,08 in) from the fusion line; and in the weld metal, the notch should be at the weld centreline.

Table 6 — Charpy V-notch impact minimum absorbed energy values

Type of steel	Average value J (minimum)		Single value J (minimum)	
	Transverse and weld metals and HAZ	Longitudinal	Transverse and weld metals and HAZ	Longitudinal
Carbon and low-alloy steels: SMYS < 415 MPa	36	50	27	38
Carbon, low-alloy and martensitic stainless steels: SMYS ≥ 415 MPa	40	60	30	45
Duplex stainless steels	40	60	30[a]	45
Reduction factors of energy requirements for sub-size specimens are 5/6 for 7,5 mm specimens and 2/3 for 5 mm specimens.				

[a] Applies to welded products that receive solution-annealing after welding.

7.6.4 Hardness testing

Hardness measuring methods and maximum allowable hardness values shall be in accordance with the selected product standard, and with ISO 15156 (all parts) if applicable to sour service.

7.6.5 Micrographic examination

Microstructure examination should be performed on all type 22Cr and 25Cr duplex stainless steel products.

The micrographic examination should be carried out over the region from the surface to the mid-thickness or at the same position as for impact testing. The area shall be at least 10 mm × 10 mm (0,40 in × 0,40 in). The ferrite content shall be determined in accordance with ASTM E562 or equivalent, and should be between 40 % to 60 % mass fraction.

The microstructure, as examined at minimum 400× magnification on a suitably etched specimen, should be free from intermetallic phases and precipitates.

If intermetallic phases and precipitates are reported, acceptance of the material should be based on corrosion testing or impact testing; see 7.6.3 and 7.6.6.

Micrographic examination in accordance with ISO 10423 is applicable to pressure-containing components made of Alloy 718.

NOTE For the purposes of this provision, ANSI/API Spec 6A is equivalent to ISO 10423.

7.6.6 Corrosion testing

7.6.6.1 Type 25Cr duplex, type 6Mo and other high-alloy austenitic grades

Corrosion testing is applicable to all types of product in type 25Cr duplex, type 6Mo and other high-alloy austenitic stainless steels.

Testing should be performed in accordance with ASTM G48, method A. The test temperature shall be 50 °C (122 °F) in pickled condition and 40 °C (104 °F) in polished condition and the exposure time shall be 24 h.

The corrosion test specimen should be taken at the same location as those for impact testing. Cut edges should be prepared as given in ASTM G48. The specimen shall be pickled before being weighed and tested. Pickling may be performed for 5 min at 60 °C (140 °F) in a solution containing 20 % volume fraction HNO_3 + 5% volume fraction HF.

The acceptance criteria are

— no pitting visible at 20× magnification;

— mass loss ≤ 4,0 g/m^2 (0,007 4 lb/yard^2).

7.6.6.2 Type 22Cr duplex (optional)

Corrosion testing of type 22Cr duplex stainless steel is optional. When specified, testing should be performed as required in 7.6.6.1 at a test temperature of 25 °C (77 °F) or by agreement. The acceptance criteria are as defined in 7.6.6.1.

7.7 Non-destructive inspection of components

7.7.1 Seamless pipes 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 ISO 3183 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.

NOTE For the purposes of this provision, ANSI/API Spec 5L is equivalent to ISO 3183.

7.7.2 Welded pipes and fittings

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

7.7.3 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. Non-machined surfaces shall be appropriately prepared before testing. The acceptance criteria are those given in ISO 10423 PSL 3 (bodies) or ASME BPVC VIII, 2007, Div. 1, Appendix 6 or 8 as relevant, or equivalent.

NOTE 1 For the purposes of this provision, ANSI/API Spec 6A is equivalent to ISO 10423.

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 should be to ISO 10423 PSL 3 (bodies), EN 10228-3 quality class 3, or equivalent.

NOTE 2 For the purposes of this provision, ANSI/API Spec 6A is equivalent to ISO 10423.

Volumetric inspection of duplex or austenitic stainless steel forgings is recommended. The user shall specify if it is required. If this option is specified, the forging should be inspected by ultrasonic testing as given in EN 10228-4. The following comments apply to the items listed in EN 10228-4:1999, Section 4.

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

b) Near-surface examination is not required.

c) Quality class 3 is required for the whole volume of the forging. In addition, any crack or crack-like indication is unacceptable and any attenuation of the back-wall echo of more than 80 % is unacceptable.

d) See a).

e) Not applicable.

f) The 6 dB drop technique shall be used for the sizing of discontinuities.

g) The reference block (DAC) technique shall be used for sensitivity setting. The blocks should be from the same group of materials, in the same heat-treatment condition and with the same sound attenuation as the forging, which should be tested.

h) Not applicable.

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

j) Angle probes should be used as specified in EN 10228-4:1999, Section 12. In such cases, the use of angle probes using longitudinal waves shall be considered.

k) To be agreed in each case.

Prior to start of the examination, it should be demonstrated that the specified FBH sizes are detectable on the forgings being examined. The boring should preferably be made by one or more FBH in the forging being examined, in the longest applicable distance from the probe.

Personnel qualifications shall be in accordance with EN 473 or ASNT-SNT-TC-1A Level II. For testing of forgings in duplex stainless steel, the operators shall have documented training in the inspection of forgings in this type material.

7.7.4 NDT personnel qualifications

Personnel qualifications shall be in accordance with the requirements of 7.11.3.2.

7.8 Fastener materials

Material for fasteners shall be selected in accordance with the requirements of the applicable design code for the connection.

Fasteners in contact with the cathodic protection system should, in general, be selected in low-alloy steel. Fasteners should be of a grade for which the SMYS does not exceed 725 MPa. For further limitations in material properties, reference is made to ISO 13628-1.

NOTE For the purposes of this provision, ANSI/API RP 17A is equivalent to ISO 13628-1.

Studs and bolts exposed to fatigue loading should have cold-rolled threads.

Fasteners shall comply with the same toughness requirements as for the components being connected.

7.9 Bending and forming operations

7.9.1 General

Fabricators of formed pressure parts shall have adequate equipment for the forming procedures and the subsequent heat treatment.

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 given individual consideration. Account should be taken of the recommendations of the steelmakers.

In the case of bending of clad pipe, special consideration of the full thermal treatment, including the clad welding operation to final product, should be taken.

7.9.2 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 in no case be utilized to increase the allowable design stress.

The hardness of any cold-formed metallic material shall conform to the maximum hardness limits in ISO 13628-1, and to ISO 15156 (all parts) for items exposed to sour service.

NOTE For the purposes of these provisions, ANSI/API RP 17A is equivalent to ISO 13628-1.

7.9.3 Hot induction bending

7.9.3.1 General

Hot induction bending of pipe shall be performed in accordance with the requirements given for ISO 15590-1 PSL 2, and the additional requirements given in the remainder of this subclause.

Hot forming by induction heating, bending and quenching down to room temperature by water spray does not require a new heat treatment, provided the process is successfully qualified and tested as required by 7.9.3.3.

The acceptable degree of oxidation of stainless steels should be agreed between the concerned parties.

At no time, prior to or during bending, should the pipe contact materials with low melting temperatures, such as zinc, copper, brass or aluminium.

If full heat treatment, involving an austenitization or solution annealing process, is applied after the induction bending operation, a prolongation of the bend shall be destructively tested in compliance with the mother pipe specification. If the mother pipe is delivered in an as-welded condition, the extent of destructive testing shall include the same testing as specified for the plate and weld procedure qualification by the mother pipe specification.

7.9.3.2 Essential variables

For all steels and nickel alloys, the essential variables of the manufacturing procedure specification (MPS) qualification shall be in accordance with ISO 15590-1, except that the maximum permissible variations shown in Table 7 should apply in general.

Table 7 — Essential variables

Essential variable	Maximum permissible variations
Bend radius, R	For all radii: Qualifies all larger radii, but no smaller
Forming velocity	± 2,5 mm/min, or ± 10,0 %, whichever is greater

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.

7.9.3.3 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 subclause 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 8 should apply.

Test samples for micrographic examination, bend, and corrosion testing of stainless steels and clad carbon/low-alloy steel shall be taken at the same locations as for tensile testing.

Except where otherwise stated in this subclause, the testing and inspection methods and acceptance criteria for induction bends are the same as required for the applicable mother pipe specification of the same steel grade and UNS number.

Dimensional control and tolerances shall be in accordance with ISO 15590-1 for all types of material.

Surface hardness testing shall be performed in accordance with ISO 15590-1.

The cladding thickness shall be verified by destructive testing at the extrados location. The cladding thickness should be a minimum of 3 mm (0,12 in) after bending.

For all bends, independent of material type, the bend body shall be visually and surface inspected in accordance with ISO 15590-1.

Tensile, impact, hardness and bend test specimens shall be taken from the same positions of the bend as specified for carbon steel in ISO 15590-1. Microstructure and corrosion tests shall be taken from the same locations as metallography is specified for bends in carbon steel.

For bends in duplex stainless steel with wall thickness greater than 25 mm (1 in), additional impact testing shall be performed during MPS qualification testing. In addition to the test pieces sampled 2 mm (0,08 in) below the outer surface, the same number of specimens shall be sampled 2 mm below inner surface in the following locations:

— transition zones base metal (if applicable);

— bend extrados base metal;

— bend intrados base metal bend weld metal (if applicable).

Table 8 — Additional testing of qualification and production bends for stainless steels, nickel alloys and clad pipe

Type of test	Duplex SS	Austenitic SS and nickel alloys	CS clad	Test conditions and acceptance criteria
Tensile	T	T	T	In accordance with mother pipe specification
Impact	T	NA	T	See 7.6.3
Through-thickness hardness	NA	NA	T[ab]	See 7.6.4
Surface hardness[c]	NA	NA	T and P	See 7.6.4
Microstructure	T	T	T[d]	See 7.6.5
Corrosion	T[c]	T[c]	NA	See 7.6.6
Bend test	NA	NA	T[b]	See ASME BPVC Section IX
Surface NDT	T and P	T and P	T and P	—
Volumetric NDT	NA	NA	T and P	—

T: required for each MPS qualification test bend

P: required for each production bend

NA: not applicable

For definition of further abbreviations see ISO 15590-1.

[a] The clad layer and interface to carbon or low-alloy steel should be tested in accordance with ASME BPVC Section IX.

[b] For clad pipe bends, the MPS qualification should repeat the mechanical testing from the clad WPQR, i.e. side bend and hardness tests (including HAZ), see ISO 10423 PSL 3.

[c] The corrosion test is applicable only to stainless steels with PREN > 40.

[d] The cladding of carbon or low-alloy steel should be 100 % inspected with LP and bond line integrity with UT in accordance with ISO 10423 PSL 3.

NOTE For the purposes of the above provisions, ANSI/API Spec 6A is equivalent to ISO 10423.

7.10 Overlay welding and buttering of components

7.10.1 General

In this subclause, requirements are given to qualify weld-overlay procedures as

— corrosion-resistant overlay;

— weld buttering.

Overlay welding shall be performed with GTAW or pulsed GMAW unless it is agreed to use other methods.

7.10.2 Corrosion-resistant overlay

Qualification of welding procedures weld overlay shall comply with ISO 10423 PSL 3.

Overlay thickness should be at least 3,0 mm (0,12 in) unless another thickness is specified. For the nickel-based alloy UNS N06625 (AWS ERNiCrMo3), the chemical composition shall comply with ISO 10423 class Fe10 unless specified otherwise by the end user.

All weld overlay surfaces should be quality controlled in accordance with ISO 10423 PSL 3 unless specified otherwise.

NOTE For the purposes of this provision, ANSI/API Spec 6A is equivalent to ISO 10423.

7.10.3 Weld buttering

Buttering of the weld end of a component that at a later stage 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 7.11. 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 (1/3 in) 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 non-destructively 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 by agreement with the end user. Acceptance criteria are the same as used for butt welds.

7.11 Welding and non-destructive testing of piping systems

7.11.1 Welding qualification requirements

7.11.1.1 General

Welding procedures for steels and nickel-based alloys should be qualified as given in ISO 15614-1 or ASME BPVC IX, and the remaining provisions of this subclause.

All weld overlay should be qualified according to ISO 10423 PSL 3 and ASME BPVC IX.

Qualification and use of WPSs is subject to the requirements of ISO 15614-1 or ASME BPVC IX.

7.11.1.2 Non-destructive testing of test welds

All test pieces should be examined visually and non-destructively in accordance with 7.11.3 following any required PWHT and prior to cutting of the test specimens.

7.11.1.3 Mechanical testing

7.11.1.3.1 General

Companies performing material testing shall have a quality management system. The quality management system should be in compliance with 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 part of ISO 13628.

If a specimen fails to meet the test requirements, two sets of retests for that particular type of 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.

7.11.1.3.2 Impact tests

Impact testing is required of welds with wall thickness > 6 mm (0,24 in) and shall meet the requirements of Table 9.

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

Table 9 — Impact test requirements

Material	Notch location[a,b]	Test temperature	Acceptance criteria[c,d]
Carbon steel with SMYS < 415 MPa	WM, HAZ	MDT or lower	36 J
Carbon steel and low-alloy steel with SMYS ≥ 415 MPa			40 J
Type 22Cr and 25Cr duplex	WM, HAZ	–46 °C or MDT, whichever is lower	40 J or lateral expansion at least 0,38 mm

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 (4/5 in), 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 5/6 for 7,5 mm specimens and 2/3 for 5 mm specimens.

7.11.1.3.3 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 15614-1 or ISO 15156 (all parts). For qualification of repair weld procedures applicable for sour service, hardness testing should be carried out as given in ISO 15156-2.

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

NOTE Hardness testing carried out as given in ISO 15614-1 is evaluated in order to comply with the hardness test requirements of ISO 15156-2 and ISO 15156-3.

Table 10 — Hardness limitations to avoid hydrogen embrittlement under cathodic protection

Material	Maximum hardness
Carbon and low-alloy steels for general applications (excluding bolting; see Table 6)	350 HV/35 HRC/330 HB
Martensitic and supermartensitic stainless steels	325 HV/33 HRC/329 HB[a]
Ferritic-austenitic stainless steels	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.
Austenitic stainless steels	For these materials, hydrogen embrittlement is not considered an issue under cathodic protection, hence no hardness limit is specified.
Nickel alloys	See ISO 15156-3.

[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 × ln(HBW) − 220,86.

[b] 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.

7.11.1.3.4 Corrosion testing

Welds in stainless steel type 6Mo, type 25Cr duplex and nickel-based alloys should be corrosion-tested as given in ASTM G48, method A. The test temperature shall be 40 °C (104 °F) 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 25 mm (1 in) along the weld by 50 mm (2 in) across the weld. Cut edges shall be prepared in accordance with ASTM G48. The whole specimen shall be pickled before being weighed and tested. Pickling may be performed for 5 min at 60 °C (140 °F) in a solution of 20 % volume fraction HNO_3 + 5 % volume fraction HF.

The acceptance criteria are as follows:

— no pitting at 20× magnification;

— mass loss should not exceed 4,0 g/m^2 (0,007 4 lb/yard^2).

Although optional, welds in stainless steel type 22Cr shall be corrosion-tested as defined above if required. The test temperature shall be 22 °C (72 °F) or by agreement, and acceptance criteria shall be as defined above.

7.11.1.3.5 Microstructural examination

Duplex stainless steel should be examined. The test samples shall comprise a cross-section of the weld metal, heat-affected zone and the base metal of the pipe. 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 WPQR shall be based on corrosion and/or impact testing.

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.

7.11.1.4 Essential variables

7.11.1.4.1 General

Requalification of a welding procedure is required on any of the changes in the essential variables listed in ISO 15614-1, ISO 15614-5 or ASME BPVC IX, and the additional essential variables listed in 7.11.1.4.2 to 7.11.1.4.8 of this part of ISO 13628.

7.11.1.4.2 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;

— for carbon steels exposed to sour service or with a SMYS above 360 MPa without PWHT: an increase in carbon equivalent (CE_{Pcm} or CE_{IIW}) of more than 0,02 for CE_{Pcm} and 0,03 for CE_{IIW}

The use of Equation (3) is recommended for carbon steels with a carbon content equal to or greater than 0,12 % mass fraction:

$$CE_{IIW} = w_C + w_{Mn}/6 + (w_{Cr} + w_{Mo} + w_V)/5 + (w_{Ni} + w_{Cu})/15 \tag{3}$$

where w_x is the percent mass fraction of element x.

The use of Equation (4) is recommended for carbon steels with a carbon content less than 0,12 % mass fraction.

$$CE_{Pcm} = w_C + w_{Si}/30 + w_{Mn}/20 + w_{Cu}/20 + w_{Ni}/60 + w_{Cr}/20 + w_{Mo}/15 + w_V/10 + 5w_B \tag{4}$$

where w_x is the percent mass fraction of element x.

7.11.1.4.3 Filler material changes requiring requalification

A change in the specific make or brand may be made, provided a new test piece is prepared in accordance with the WPS for impact testing of the weld metal. The tested make or brand may be used, provided the results of the weld metal impact testing meet the requirements of Table 9.

7.11.1.4.4 Welding process changes requiring requalification

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

7.11.1.4.5 Heat input changes requiring requalification

For all material types, the maximum variation in heat input shall be ± 15%.

7.11.1.4.6 Welding position changes requiring requalification

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

7.11.1.4.7 Changes in technique requiring requalification

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

7.11.1.4.8 Joint changes requiring requalification

A decrease in bevel angle, for bevel angles less than 30°, requires requalification.

7.11.2 Welding requirements

7.11.2.1 General

All welding and related activities should satisfy the requirements of ISO 3834-2 and the additional requirements of 7.11.2 of this part of ISO 13628.

WPS shall be established for all welding intended for use in the fabrication of piping 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 titanium-based alloys. 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 ≥ 40 (e.g. UNS S32654 and UNS S34565), the requirements given for stainless steel type 6Mo of this part of ISO 13628 shall apply.

7.11.2.2 Welding coordination

All welding coordination should be as given 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 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.

7.11.2.3 Welding inspection and qualification of welding inspectors

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

Welding inspection should be performed before, during and after welding. All inspections should be reported to the responsible welding coordinator.

The inspection frequency shall be sufficient to report weekly quality status during fabrication, based on welding inspection reports. Prior to fabrication start-up, the contractor should implement a system for recording of quality status. 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 NS 477 or EWF/IIW or equivalent.

7.11.2.4 Welder and welding operator qualification

All bracers, welders and welding operators shall be qualified in accordance with ISO 9606-1, EN 1418 or ASME BPVC Section IX, as applicable, or equivalent codes.

7.11.2.5 Welding consumables

7.11.2.5.1 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 Type 3.1.B.

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 (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 Type 2.2.

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

7.11.2.5.2 Carbon and carbon manganese steels

For welding carbon and low-alloy steels having SMYS $\geq$ 415 MPa, low-hydrogen type consumables (H_D = 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.

7.11.2.5.3 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 sulfur content shall not exceed 0,015 % mass fraction.

7.11.2.5.4 Duplex stainless steels

A matching consumable with enhanced Ni content compared to the base material should be used. The sulfur content shall not exceed 0,015 % mass fraction.

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

7.11.2.5.5 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.

When PWHT is required after joining austenitic stainless steels to carbon steels, the weld deposit should be made using a nickel-based consumable.

7.11.2.6 Interpass temperature

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:

— 250 °C maximum for carbon and low-alloy steels;

— 150 °C maximum for stainless steels and nickel alloys.

7.11.2.7 Backing and shielding gas

Back-shielding 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.

7.11.2.8 Welding of clad materials

When welding clad materials from both sides, the carbon steel should be completely welded prior to welding the cladding. Carbon steel or low-alloy steel weld metal shall not be deposited onto a high-alloy base material or weld metal.

7.11.2.9 Welding of o-lets

The weld bevel of o-lets shall be completely 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, sufficient root gap shall be ensured.

7.11.2.10 Production test (optional)

A production test programme should be established for the contracted scope of work. Verification of previously qualified WPSs and weldability of actual material used shall be considered when establishing the programme.

For those materials requiring impact testing, the production tests should include specimens extracted from the fusion line, FL+2 and FL+5 positions in addition to those required in Table 9.

Production tests, though optional, shall be carried out when specified. Each production test should be carried out and documented as for the relevant welding procedure qualification test.

7.11.2.11 Post-weld heat treatment

Careful considerations should be made if PWHT involves assemblies with differing material grades. Special qualifications shall be considered.

PWHT should be performed for welded joints of carbon and low-alloy steels having a nominal wall thickness in the weld cross-section > 50 mm, unless fracture mechanics testing shows acceptable values in the as-welded condition. In cases where the minimum design temperature is less than −10 °C (+14 °F), the thickness limit shall be specially determined.

If PWHT is used to obtain adequate resistance of welded joints against any kind of stress corrosion cracking, this should be performed for all thicknesses.

The PWHT temperature shall be at least 20 °C (36 °F) lower than the base material tempering temperature, unless the PQR for the relevant base material is documented to fulfil minimum specified mechanical strength, including yield strength, after a simulated PWHT at the relevant temperature.

7.11.3 Inspection and non-destructive testing (NDT) of welds

7.11.3.1 General

Companies performing visual inspection and NDT activities should have a quality system as given in ISO/IEC 17020 or equivalent.

All activities covered by 7.11.3 cover final inspection of welded joints.

All non-destructive testing should be carried out as given in ASME BPVC V.

7.11.3.2 Qualification of inspectors and NDT operators

Personnel performing visual inspection or non-destructive testing shall be certified for the test method used in accordance with

— ASME BPVC V or EN 473 for visual inspection;

— ISO 9712, ACCP or EN 473 for NDT methods.

The roles and responsibilities of NDE personnel shall be as defined in ISO 9712.

7.11.3.3 Extent of visual inspection and non-destructive testing

All pressure-containing welds should be 100 % visually inspected and 100 % non-destructively tested for surface and volumetric defects. The surface inspection shall be made by either magnetic particle or dye penetrant methods, and the volumetric testing shall be made by radiography or ultrasonic inspection methods. This includes all buttering welds.

Volumetric testing of butt welds from weld o-let to header pipe should be made as far as possible.

Visual inspection should include, in addition to all welds in the piping system, all supports and attachments welded to the piping.

When gas metal arc welding (131 MIG/135 MAG/GMAW) without pulsed current is applied, ultrasonic testing should be carried out to verify that there is no sidewall lack of fusion, in addition to radiographic testing.

7.11.3.4 Ultrasonic testing

DAC reference curves should be produced from reference blocks whose thicknesses and side-drilled hole diameters are in accordance with Table 11.

Ultrasonic testing procedures should be sufficiently detailed to ensure that 100 % of the weld body and heat-affected zones are examined for longitudinal defects as given in ASME BPVC V.

All indications exceeding 20 % DAC should be investigated to the extent that they can be evaluated in terms of the acceptance criteria. The examination report shall include the position, the echo height, length, depth and type of defect.

Ultrasonic testing of clad pipe, and austenitic and duplex stainless steels requires a specific procedure; probes and reference blocks should be prepared from the actual weld. The procedure used shall be qualified to demonstrate that relevant defects are detected. Grinding of the weld cap should be considered dependent on the procedure qualification.

Table 11 — Calibration reference block requirements

Thickness of material being examined T mm	**Thickness of block** t mm	**Diameter of hole** mm	**Distance of hole from one surface**
$10 < T \leq 25$	20 or T	$3 \pm 0,2$	$t/2$ and $t/4$ Additional holes are allowed and recommended
$25 < T \leq 50$	40 or T		
$50 < T \leq 100$	75 or T		
$100 < T \leq 150$	125 or T	$6 \pm 0,2$	
$150 < T \leq 200$	175 or T		
$200 < T \leq 250$	225 or T		
$T > 250$	275 or T		

7.11.3.5 Acceptance criteria

The defect acceptance level shall be in accordance with ASME B31.3, Chapter IX, High Pressure Service, unless specified otherwise by the designer.

For surface testing of welds by magnetic particle or liquid penetrant testing, the acceptance criteria shall be in accordance with ASME BPVC VIII, Appendix 6 and Appendix 8, respectively. No indications are allowed on sealing band surfaces.

Weld zones in stainless steels and nickel alloys should be visually examined on the inside and outside, and shall be evaluated as follows.

— Oxidation levels showing light brown to brown colour are acceptable.

— Oxidation levels showing a narrow band of dark brown colour and intermittent spots of blue colour are acceptable.

— Darker or more extensive oxidation colours are not acceptable, and should be chemically or mechanically removed.

7.11.4 Repair

Before repair welding, the defect should be completely removed.

The excavated area should have smooth transitions to the metal surface and allow good access for both NDT after excavation and subsequent repair welding. After excavation, complete removal of the defect should be confirmed by dye penetrant or magnetic particle testing. PWHT shall be performed after repair if specified for the original weld.

The excavated groove should be at least 50 mm long, measured at defect depth even if the defect itself is smaller.

Defects spaced less than 100 mm apart should be repaired as one continuous defect.

After repair welding, the complete weld (i.e. the repaired area plus at least 100 mm on each side) should 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.

Rewelding should include complete removal of the original weld and HAZ.

Repair welding shall be performed using either the same WPS as for the original weld, or a separately qualified procedure.

8 Fabrication and manufacturing considerations

8.1 External corrosion protection

Considerations involving external corrosion protection of all components should be as given in ISO 13628-4.

External corrosion control shall be provided by appropriate materials selection, coating systems, and cathodic protection. Cathodic protection design guidelines are contained in DNV-RP-B401 and NACE RP 0176. A corrosion control programme is an ongoing activity that consists of testing, monitoring and replacement of spent equipment. The implementation of a corrosion control programme is beyond the scope of this part of ISO 13628.

8.2 Colours

Top coat colours should follow the recommendation in ISO 13628-1:2005, Annex B and ISO 13628-8.

NOTE For the purpose of this provision, ANSI/API RP 17A is equivalent to ISO 13628-1 and API 17H is equivalent to ISO 13628-8.

8.3 Material traceability

All pressure-containing and pressure-controlling parts of equipment manufactured to this part of ISO 13628 should comply with the requirements of PSL 2 or PSL 3 as given in ISO 10423. These PSL designations define different levels of requirements.

NOTE For the purposes of this provision, ANSI/API Spec 6A is equivalent to ISO 10423.

It is not necessary that structural components and other non-pressure-containing/controlling parts of equipment manufactured to this part of ISO 13628 comply with the requirements of PSL 2 or PSL 3.

9 Installation, operation and maintenance considerations

9.1 Installation requirements

The template or support structure should provide sufficient capability to allow for all installation requirements. Different types of installation vessel, such as drilling rigs, subsea construction vessels or crane barges, should be evaluated.

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

— loadout;

— transportation to site;

— launch capability;

— crane capacity;

— buoyancy capability;

— ballast/flooding system;

— system for lowering to seabed;

— positioning and repositioning capability;

— levelling system;

— Shock absorbers or any soft landing devices may be included, as required, in order to allow for specified maximum landing velocity.

— foundation interface.

9.2 Operations considerations

9.2.1 Operability of the subsea facility is often critical to the success of a development. The purpose of 9.2 is to provide a listing of general issueswhich often arise during the operation of subsea production systems.

9.2.2 The following operations issues should be considered:

— transportation and handling;

— installation;

— drilling and completion;

— hook-up and commissioning;

— intervention;

— maintenance;

— decommissioning.

9.2.3 The subsea production system should

— allow lifting with rig crane (when relevant);

— require a minimum of special transportation requirements;

— be marked with a unique number, dry mass and lift-point capacities.

9.2.4 Due consideration should be given to offshore vessel-lifting capabilities when designing equipment for offshore handling.

9.3 Maintenance considerations

9.3.1 General

There are three general categories of maintenance for subsea wells and associated facilities:

a) well maintenance;

b) seabed equipment maintenance;

c) surface equipment maintenance.

9.3.2 Planning

Planning for maintenance should begin during the design of the subsea systems and hardware. 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. wet divers with hand tools) are warranted, while in other applications remote diverless tools can be necessary.

Special maintenance tools and procedures should be thoroughly tested and evaluated during onshore testing programmes. Outline procedures should be developed and, if practical, full-scale tests performed. Detailed photo and/or video documentation of subsea hardware and maintenance tools 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.

The organization responsible for operating the subsea installation should assist with coordination of maintenance work. This helps to ensure that all maintenance work and other activities are carried out in a safe and efficient manner.

9.3.3 Seabed equipment maintenance

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. Modules may be removed and replaced using tools deployed on pipework strings, wirelines and ROV, or by manned intervention methods involving wet divers, one-atmosphere habitats and manned vehicles.

In situ repairs are those made without recovery of the equipment to the surface, and may be accomplished by ROTs, ROVs or by mono- or hyperbaric diving.

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 manifolded systems, it can be possible to isolate the affected well(s) and continue normal operations. Steps should then be taken, such as 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.

Pressure-containing conduits should be bled down to ambient pressure. If possible, hydrocarbons and other potentially contaminating fluids should be displaced from flow circuits.

Electrical circuits should be de-energized if they pose a hazard for divers and other maintenance systems.

Lowering and recovering of tools and modules on drill strings or cables should be executed with care to minimize risks of damage to seafloor equipment by dropped objects or by impact during positioning or landing.

After maintenance operations on subsea equipment are completed, the subsea system should be thoroughly tested before being put back into service. Comprehensive records of all maintenance work should be maintained.

9.4 Requirements during installation

9.4.1 General

9.4.1.1 The structures and modules should be designed so that they can be installed with standard offshore installation methods without the requirement for purpose-designed installation aids. The design should focus on simple, reliable and efficient offshore operations. Restrictions with regard to sequence of marine installations and drilling rig activities should be minimized.

During installation, the subsea production system 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 subsequent to connection;
- allow for quick, easy and reliable make-up of modules;
- have facilities for testing prior to deployment by the use of test skids, if applicable;
- minimize entry of water or contamination into hydraulic circuits during connections (which can jeopardize system functionality);
- facilitate orientation and guidance during installation;
- may include shock absorbers or any soft landing devices, as required, in order to allow for specified maximum landing velocity.
- provide means (temporary or otherwise) of gauge pigging of flowlines if applicable;
- be tolerant of small amounts of seabed debris between the interface connections or allow flushing prior to make-up operation;
- avoid loss of harmful fluids during installation and operation;
- minimize impact of equipment malfunction leading to discharge of hydrocarbons;
- facilitate periodic testing to verify that the system is fully functional.

No activities other than those related to re-establishment of two barriers should take place if one barrier fails. One barrier is acceptable if it is evident that the reservoir cannot produce to the environment by means of natural flow.

9.4.1.2 The contractor should produce an IDS and outline installation procedure as input to the installation contractor. The following information shall be included in these documents, as a minimum:

— 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 levelling;

— 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 minimize hydrodynamic coefficients in order to maximize installable sea states.

All subsea equipment and lifting equipment should be designed for safe subsea reinstallation, when applicable. The use of lifting frames should be avoided if this imposes large lifting height or reduces safety.

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

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

9.4.2 Installation method and equipment

9.4.2.1 The installation method and equipment selected for the subsea structure and piping system shall ensure safe and reliable operation in accordance with the selected intervention strategy.

9.4.2.2 The subsea production system should fulfil the following criteria.

— The installation equipment (temporary and permanent) should not cause obstructions or restrict intervention access.

— Disconnection of lifting slings, lifting beams/frames/arrangements used during installation should be carried out according to the selected intervention strategy. A backup system may be provided.

— The installation system should not represent any hazard to the permanent works during installation, release, reconnection and removal.

— Lifting/installation arrangements should be designed to minimize lifting height.

— An installation lifting frame (optional) should include a sling laydown area and attachment for tugger lines, and, if required, platforms and support for installation instrumentation, temporary access ladders, and inspection platforms.

9.4.2.3 It is recommended that the subsea system

— be video-recorded during installation operations;

— use installation tools with a fail-safe design;

— allow flushing of hydraulic circuits subsequent to connection of interfaces;

— where possible, not be dependent on unique installation vessels;

— have position indicators on all interface connections;

— be installable utilizing a minimum number of installation vessels;

— require installation within a defined practical weather window that is consistent with the specific type of installation equipment and vessel being used;

— require a minimum number of special installation tools;

— facilitate fully reversible sequential installation techniques/operations.

9.4.3 Vessel considerations

A benefit analysis, comparing the use of a single multi-purpose vessel for performing several installation tasks (such as survey, installation of structures and subsea tie-in) against the use of several specialized vessels, should be considered. Necessary installation analyses and procedures should be outlined in the engineering phase. Final procedures should be established once installation vessels have been selected.

9.4.4 Hook-up and commissioning

This subclause 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;

d) verification of the subsea production system.

9.4.5 Detailed requirements

Prior to installation, all equipment should have been subjected to a comprehensive integration test programme. The precommissioning/commissioning procedures should be based on the integration test procedures and operating procedures. The precommissioning/commissioning activities described in 9.4.4 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 distribution system.

10 ROV/ROT aspects

Intervention systems may be operated by diver, ROV or specific ROT. The design of ROV interfaces with the subsea production system shall be in accordance with ISO 13628-8.

NOTE For the purposes of this provision, API 17H is equivalent to ISO 13628-8.

It is recommended that the subsea template, structure and its equipment be designed to provide the following, in order 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 re-established in the case of a broken wire or pile overpull;

— 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.

  The purpose of the clearance is to avoid any unintended impacts or clashes during installation and retrieval. Recommended clearances are

  — minimum 1,0 m (3,28 ft) for monohull operations and 0,5 m (1,64 ft) for semi-submersible operations, at 0,8 m (2,62 ft) above guidepost top and upward when running on guide wires;

  — minimum 0,2 m (0,66 ft) when running on guideposts;

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

11 Lifting considerations

11.1 Pad eyes

Pad eyes should be designed as given in ISO 13628-4. Load capacities of pad eyes should be marked as given in ISO 13628-4. Alternatively, an engineered lift can be implemented and utilized for the design of pad eyes if agreed by the end user and installation contractor. Testing of pad eyes might not be required where impractical.

NOTE For the purposes of these provisions, API Spec 17D is equivalent to ISO 13628-4.

11.2 Other lifting devices

Other lifting devices, such as running tools, shall be designed as specified in ISO 13628-4. 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. Load capacity should be marked on all lifting devices as given in ISO 13628-4.

NOTE For the purposes of these provisions, API Spec 17D is equivalent to ISO 13628-4.

12 Equipment marking

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 both on the subsea packages and on their control units, using common abbreviations listed in this part of ISO 13628. If the valve arrangements are unique, the documentation should clearly define the abbreviations used in the marking of equipment.

The colour and marking system should fulfil the following functions:

— 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.

The marking system should enable positive verification of the end stop and/or locked position for retrievable components, such as guideposts to lockdown clamps, etc.

Subsea marking should follow the principles listed in ISO 13628-8.

NOTE For the purposes of this provision, API 17H is equivalent to ISO 13628-8.

13 Transportation and storage

13.1 General

It is recommended that the subsea production system

— be equipped with lifting points and primary-load-bearing structures that are certified and labelled 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 manifold and valves should be filled with a preservation fluid prior to delivery, and should take into account environmental conditions that may be encountered.

13.2 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;

— electrical systems.

13.3 Sea-fastening

During the design phase of the manifold system, sea-fastening of the manifold shall be considered. The sea-fastening methods shall meet typical industry standards, such as Reference [53].

14 Abandonment provisions

14.1 General

If it is expected that the template or manifold support will be recovered at the end of the project, its design should include provisions for this requirement.

14.2 Decommissioning

The variable-cost elements related to decommissioning are the plugging and abandonment of wells, any necessary removal of seabed equipment, seabed clean-up and final survey. It may be permissible to abandon part or all of the system on site.

The effect on the operating environment, e.g. discharge of hydrocarbons during abandonment/ decommissioning, should be minimized. It is recommended that flowlines and manifolds be pigged clean, flushed, flooded with water and capped if they are left in place.

The subsea production system should include elements/features that ease decommissioning, such as attachment points for lifting equipment.

The subsea production system at decommissioning should

— allow abortion of operations without compromising safety;

— allow the flushing of production products from flowlines, storage tanks, manifolds, etc., prior to flooding with seawater;

— allow the removal of any hydrocarbon-containing equipment, if left in place, flushed clean;

— allow the recovery of flushed fluids at the surface to avoid pollution.

14.3 Design

The subsea production system should be designed to

— facilitate easy abandonment in a safe manner;

— allow refurbishment and reuse of equipment (if applicable).

14.4 Post-abandonment operation

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

14.5 Structures

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

14.6 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.

14.7 Templates

General guidelines for template removal are as follows.

a) Disconnect all risers, pipelines, flowlines, control and power lines.

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 ROV-mounted subsea video cameras.

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

Annex A
(informative)

Typical manifold data sheet

General

Pipe Design Code		Max. Temp.	
Design Pressure		Min. Temp.	
Project Depth		Insulation Required	
Foundation Type		Estimated Weight	

Headers

	Production ☐	Test ☐	Water Inj. ☐	Gas Lift ☐	Chemical ☐
No. of Headers					
Size					
No. of Hubs					
Piggable					
Iso. Valve					
Hub					

Materials

Header Piping		Branch Valves	
Branch Piping		Load-bearing Structure	
Header Valves		Secondary Structural Steel	
Hub Connection		Insulating Materials	

Pigging

Required		Pig Isolation Valve (Qty)	
Removable Pigging Loop		Pig Isolation Valve Style	
Min. Bend Radius		Pig Isolation Valve Actuator	

Branches

	Production ☐	Test ☐	Water Inj. ☐	Gas Lift ☐	Chemical ☐
No. of Branches					
Size					
Valve Style					
No. of Valves/Branch					
Double Block Valve					
Hub					

Control System

Type		Tubing Size	
No. of SCMs		Tubing Material	
Low Pressure Operating Pressure		Connection Type	
High Pressure Operating Pressure			

Sensors

No. for Pressure/Temperature		Sand Detector	
No. of Pig Detectors		Erosion/Corrosion Monitor	

Testing Requirements

Valves		Manifold Function Test	
Manifold Hydro Test		Pad Eye Lift Test	
Manifold Gas Test		Control System Test	
CP Continuity			

Chemical Injection

No. of Different Chemicals		Tube Size	
No. of Injection Points		Tube Material	

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