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Petroleum, petrochemical and natural gas industries — Materials selection and corrosion control for oil and gas production systems (ISO 21457:2010)

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National foreword

This British Standard is the UK implementation of EN ISO 21457:2010.

The UK participation in its preparation was entrusted to Technical Committee PSE/17/-/7, UK experts in ISO TC 67 Working Groups.

A list of organizations represented on this committee can be obtained on request to its secretary.

This publication does not purport to include all the necessary provisions of a contract. Users are responsible for its correct application.

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Foreword

This document (EN ISO 21457:2010) has been prepared by Technical Committee ISO/TC 67 "Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries" in collaboration with Technical Committee CEN/TC 12 "Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries" the secretariat of which is held by AFNOR.

This European Standard shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by March 2011, and conflicting national standards shall be withdrawn at the latest by March 2011.

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Endorsement notice

The text of ISO 21457:2010 has been approved by CEN as a EN ISO 21457:2010 without any modification.

Contents

Page

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.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

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ISO 21457 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries*.

Introduction

The provision of well-established and robust material selection guidelines offers a means of satisfying long-term materials performance that meet the minimum requirements for a broad range of end users in the petroleum, petrochemical and natural gas industries. An additional benefit can be to enable product suppliers to develop, manufacture and provide off-the-shelf equipment that meets these requirements.

Oil and gas production projects benefit from a structured evaluation of materials used for the different fluids being handled. Therefore, the main objective of this International Standard is to provide general requirements with guidelines for the selection of materials for systems and components, with due consideration to the transported fluids and the external environment.

It is the end user's responsibility to provide a project document with respect to implementation of the requirements and guidelines of this International Standard, and to specify the design conditions for material selection. In addition to the end user, the organization responsible for the facility or for the equipment design, or for both, is regarded as responsible for materials selection.

This International Standard is developed to provide responsible parties with a structured process to carry out materials selection in a consistent manner as a part of the engineering work, based upon a design basis for a particular installation. This International Standard is intended for use by oil companies and engineering contractors.

Users of this International Standard are advised that further or differing requirements might be needed for individual applications. This International Standard is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment or engineering solutions for the individual application. This can be particularly applicable where there is innovative or developing technology. Where an alternative is offered, it is advisable that the vendor identify any variations from this International Standard and provide details.

Petroleum, petrochemical and natural gas industries — Materials selection and corrosion control for oil and gas production systems

1 Scope

This International Standard identifies the corrosion mechanisms and parameters for evaluation when performing selection of materials for pipelines, piping and equipment related to transport and processing of hydrocarbon production, including utility and injection systems. This includes all equipment from and including the well head, to and including pipelines for stabilized products. This International Standard is not applicable to downhole components.

Guidance is given for the following:

- corrosion evaluations;
- materials selection for specific applications, or systems, or both;
- performance limitations for specific materials;
- corrosion control.

This International Standard refers to materials that are generally available, with properties that are known and documented. It also allows other materials to be evaluated and qualified for use.

This International Standard does not provide detailed material requirements or guidelines for manufacturing and testing of equipment. Such information can be found in particular product and manufacturing standards.

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 15156-1[1], *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 1: General principles for selection of cracking-resistant materials*

ISO 15156-2[1], *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons*

ISO 15156-3[1], *Petroleum and natural gas industries — Materials for use in H_2S-containing environments in oil and gas production — Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys*

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1) ISO 15156 (all parts) has been adopted by NACE as NACE MR0175/ISO 15156.

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

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

3.1.1
aquifer water
water from an underground layer of water-bearing permeable rock or unconsolidated materials

3.1.2
carbon steel
alloy of carbon and iron containing up to 2 % mass fraction carbon and up to 1,65 % mass fraction manganese and residual quantities of other elements, except those intentionally added in specific quantities for deoxidation (usually silicon and/or aluminium)

NOTE Carbon steels used in the petroleum industry usually contain less than 0,8 % mass fraction carbon.

[ISO 15156-1:2009, definition 3.3]

3.1.3
corrosion-resistant alloy
alloy intended to be resistant to general and localized corrosion by oilfield environments that are corrosive to carbon steels

NOTE This definition is in accordance with ISO 15156-1 and is intended to include materials such as stainless steel with minimum 11,5 % (mass fraction) Cr, and nickel, cobalt and titanium base alloys. Other ISO standards can have other definitions.

3.1.4
end user
owner or organization that is responsible for operation of an installation/facility

3.1.5
free-machining steel
steel composition to which elements such as sulfur, selenium or lead have been intentionally added to improve machinability

3.1.6
fugacity
non-ideal partial pressure that a component in a mixture exerts in the vapour phase when in equilibrium with the liquid mixture

NOTE The fugacity factor depends on the temperature and the total pressure.

3.1.7
glass-fibre-reinforced plastic
composite material made of thermosetting resin and reinforced with glass fibres

3.1.8
hydrogen-induced cracking
HIC
planar cracking that occurs in carbon and low alloy steels when atomic hydrogen diffuses into the steel and then combines to form molecular hydrogen at trap sites

NOTE Cracking results from the pressurization of trap sites by hydrogen. No externally applied stress is needed for the formation of hydrogen-induced cracks. Trap sites capable of causing HIC are commonly found in steels with high impurity levels that have a high density of planar inclusions and/or regions of anomalous microstructure (e.g. banding) produced by segregation of impurity and alloying elements in the steel. This form of hydrogen-induced cracking is not related to welding.

[ISO 15156-1:2009, definition 3.12]

3.1.9
hydrogen stress cracking
HSC

cracking that results from the presence of hydrogen in a metal and tensile stress (residual and/or applied)

NOTE HSC describes cracking in metals that are not sensitive to SSC but which can be embrittled by hydrogen when galvanically coupled, as the cathode, to another metal that is corroding actively as an anode. The term “galvanically induced HSC” has been used for this mechanism of cracking.

[ISO 15156-1:2009, definition 3.13]

3.1.10
liquid metal embrittlement

form of cracking caused by certain liquid metals coming into contact with specific alloys

3.1.11
low alloy steel

steels containing a total alloying element content of less than 5 % mass fraction, but more than that specified for carbon steel

EXAMPLE AISI 4130; AISI 8630; ASTM A182 Grade F22[20].

3.1.12
manufacturer

firm, company or corporation responsible for making a product in accordance with the requirements of the order, or with the properties specified in the referenced product specification, or both

3.1.13
marine atmosphere

atmosphere over and near the sea

NOTE A marine atmosphere will extend a certain distance inland, depending on topography and prevailing wind direction. It is heavily polluted with sea-salt aerosols (mainly chlorides).

[ISO 12944-2:1998, definition 3.7.4]

3.1.14
maximum operating temperature

maximum temperature to which a component is subjected, including during deviations from normal operations, such as start-up/shutdown

3.1.15
onshore

inland area with a non-chloride-containing atmosphere

3.1.16
operating temperature

temperature to which a component is subjected during normal operation

3.1.17
pH stabilization

increasing the bulk pH by addition of a suitable chemical to reduce CO_2 corrosion in hydrocarbon systems with condensing water

3.1.18
pitting resistance equivalent number
PREN

F_{PREN}

number, developed to reflect and predict the pitting resistance of a stainless steel, based upon the proportions of Cr, Mo, W and N in the chemical composition of the alloy

NOTE 1 For the purposes of this International Standard, F_{PREN} is calculated from Equation (1):

$$F_{\mathrm{PREN}} = w_{\mathrm{Cr}} + 3{,}3(w_{\mathrm{Mo}} + 0{,}5w_{\mathrm{W}}) + 16w_{\mathrm{N}} \tag{1}$$

where

w_{Cr} is the percent (mass fraction) of chromium in the alloy;

w_{Mo} is the percent (mass fraction) of molybdenum in the alloy;

w_{W} is the percent (mass fraction) of tungsten in the alloy;

w_{N} is the percent (mass fraction) of nitrogen in the alloy.

NOTE 2 Adapted from ISO 15156-3:2009, definition 3.10, and ISO 15156-3:2009, 6.3.

3.1.19
type 13Cr

martensitic stainless steel alloys with nominal 13 % Cr mass fraction alloying

EXAMPLE UNS S41000; UNS S41500.

3.1.20
type 316

austenitic stainless steel alloys of type UNS S31600/S31603

3.1.21
type 6Mo

austenitic stainless steel alloys with PREN $\geqslant$ 40 and a nominal Mo alloying content of 6 % mass fraction, and nickel alloys with Mo content in the range 6 % to 8 % mass fraction

EXAMPLE UNS S31254; UNS N08367; UNS N08926.

3.1.22
type 22Cr duplex

ferritic/austenitic stainless steel alloys with 30 $\leqslant$ PREN $\leqslant$ 40 and Mo $\leqslant$ 2,0 % mass fraction

EXAMPLE UNS S31803; UNS S32205.

3.1.23
type 25Cr duplex

ferritic/austenitic stainless steel alloys with 40 $\leqslant$ PREN $\leqslant$ 45

EXAMPLE UNS S32750; UNS S32760.

3.1.24
stress corrosion cracking
SCC
cracking of metal involving anodic processes of localized corrosion and tensile stress (residual and/or applied)

NOTE 1 Parameters that influence the susceptibility to SCC are temperature, pH, chlorides, dissolved oxygen, H_2S and CO_2.

NOTE 2 The above definition differs from that of the same term given in ISO 15156-1:2009, definition 3.21, since it includes external environments.

3.1.25
sulfide stress cracking
SSC
cracking of metal involving corrosion and tensile stress (residual and/or applied) in the presence of water and H_2S

NOTE SSC is a form of hydrogen stress cracking (HSC) and involves embrittlement of the metal by atomic hydrogen that is produced by acid corrosion on the metal surface. Hydrogen uptake is promoted in the presence of sulfides. The atomic hydrogen can diffuse into the metal, reduce ductility and increase susceptibility to cracking. High strength metallic materials and hard weld zones are prone to SSC.

[ISO 15156-1:2009, definition 3.23]

3.2 Abbreviated terms

AFFF	aqueous film-forming foams
API	American Petroleum Institute
ASCC	alkaline stress corrosion cracking
ASME	American Society of Mechanical Engineers
CP	cathodic protection
CRA	corrosion-resistant alloy
CUI	corrosion under insulation
GRP	glass-fibre-reinforced plastic
HAZ	heat-affected zone
HB	Brinell hardness
HDG	hot-dip galvanized
HIC	hydrogen-induced cracking
HRC	Rockwell hardness C scale
HSC	hydrogen stress cracking
HVAC	heating-ventilation-air conditioning
MEG	monoethylene glycol
MIC	microbiologically induced corrosion

PE	polyethylene
PP	polypropylene
PREN	pitting resistance equivalent number
PTFE	polytetrafluoroethylene
PVC	polyvinyl chloride
SCC	stress corrosion cracking
SMYS	specified minimum yield strength
SS	stainless steel
SSC	sulfide stress cracking
SWC	step-wise cracking
TEG	triethylene glycol
UNS	unified numbering system (for alloys)

4 Design information for materials selection

This International Standard provides guidelines for material selection for oil and gas production facilities. To enable the contractor to perform the material selections for the facility, the end user should as a minimum provide the information specified in Table 1 at the time of enquiry and contract.

Table 1 — Design information for materials selection

Information to be provided	Subclause
Project design basis, ref. Annex A	6.1
Corrosion-prediction model	6.2.1 and 6.2.2.2
Future changes in reservoir H_2S- content	6.2.2.4
Methodology or model for pH calculation of produced water	6.2.3.2
Formation water analysis	6.2.3.2
Content of mercury in production fluids or gas	6.2.3.8
The oxygen content in de-aerated seawater for injection	6.3
Erosion-prediction model	6.5
Temperature limitations for use of stainless steels in marine atmosphere	6.6.2, Table 3
Compliance with DNV-RP-F112[21] for duplex stainless steel exposed to cathodic protection	6.6.4
Limitations in mechanical properties and use of materials	6.9
Temperature limitations for non-metallic materials	7.4.2, Table 9
Environmental requirements regarding use of corrosion inhibitors	8.1
Model for inhibitor evacuation, corrosion inhibition test methods and acceptance criteria	8.1
Use of external coatings to increase maximum temperature for stainless steel (SS)	8.3
Applicable standard for cathodic protection (CP) design to be defined	8.5.1
Strength and hardness limitation of fasteners in marine atmosphere	8.9

5 Materials selection report

Corrosion evaluations and materials selection should be documented in a report for further use by the project and operations.

The following elements should be included:

- short description of the project and expected facilities, e.g. field layout, remoteness of location, manned versus unmanned facilities, etc.;
- materials-related design input data for the operating conditions during the design life of the facility, e.g. temperatures, pressures, fluid composition, sand production, etc. (see Annex A);
- corrosion evaluations and materials selection;
- requirements for corrosion inhibitor efficiency and availability;
- requirements for corrosion control, e.g. CP and coatings;
- requirements for corrosion monitoring;
- identification of uncertainties from a materials perspective, new application for materials, use of new grades;
- need for material qualification testing.

6 General guidelines for corrosion evaluations and materials selection

6.1 General

The materials selection process shall take into account all statutory and regulatory requirements. The project design criteria, such as design lifetime, inspection and maintenance philosophy, safety and environmental profiles, operational reliability and specific project requirements, should be considered.

In general, robust materials selection should be made to ensure operational reliability throughout the design life. For offshore installations and particularly subsea, access for the purposes of maintenance and repair can be limited and costly, and should be carefully considered in the design.

Materials selection should normally be based on an evaluation of corrosion and erosion as described in the following subclauses. All internal and external media should be considered for the entire design life. This should also include the stages of transportation, storage, installation, testing and preservation. Degradation mechanisms not specifically covered in this International Standard, such as fatigue, corrosion-fatigue, wear and galling, should be considered for relevant components and design conditions.

Mechanical properties and usage limitations for different material grades should comply with applicable design code requirements and guidelines given in 6.9. The material weldability should also be considered to ensure an effective fabrication.

Cost and material availability have a significant influence on materials selection, and evaluations should be made to support the final selection.

NOTE If life-cycle cost evaluations are considered appropriate, then ISO 15663-2 describes one methodology.

6.2 Internal corrosion in oil and gas production and processing

6.2.1 Corrosion evaluation

A corrosion evaluation should be carried out to determine the general corrosivity of the internal fluids for the materials under consideration. The corrosion mechanisms and the specified process design parameters included in 6.2.2 and 6.2.3 should be considered.

The corrosion evaluation should be based on a corrosion prediction model, or on relevant test or field corrosion data agreed with the end user. General and localized corrosion of carbon steel takes place over time, and the anticipated corrosion rate should be calculated for the operating conditions.

6.2.2 Corrosion mechanisms

6.2.2.1 General

For wet hydrocarbon systems made of carbon steel or corrosion-resistant alloy (CRA) the corrosion mechanisms indicated in Table 2 should be evaluated.

Table 2 — Materials prone to internal corrosion mechanisms in hydrocarbon systems

Corrosion mechanism	Carbon and low alloy steel	CRA
CO_2 and H_2S corrosion	Yes	Yes[a]
MIC	Yes	Yes
SSC/SCC caused by H_2S	Yes	Yes
HIC/SWC	Yes	No
ASCC	Yes	No
SCC without H_2S	No	Yes

[a] The presence of H_2S in combination with CO_2 can also lead to localized attacks of CRAs. The critical parameters are temperature, chloride content, pH and partial pressure of H_2S. There are no generally accepted limits and the limits vary with type of CRA.

6.2.2.2 CO_2 and H_2S corrosion

CO_2 corrosion is one of the most common corrosion mechanisms that occur on carbon steels in oil and gas production and processing systems. The most important parameters for CO_2 corrosion are temperature, partial pressure of CO_2, pH, content of organic acids and flow conditions. Several models for the prediction of CO_2 corrosion on carbon steel are available, and the model used should be agreed with the end user.

The presence of H_2S in combination with CO_2 influences the corrosion of carbon steel. The type of corrosion is dependent on the proportions of these constituents in the production fluids. For carbon steel, general mass-loss corrosion caused by H_2S-dominated corrosion conditions is rarely a problem, since the iron sulfide scale is generally protective. However, if the scale is damaged, then localized pitting corrosion can occur. Deposition of elemental sulfur or solids due to stagnant flow conditions may promote such localized corrosion. No generally accepted corrosion models exist to predict this form of localized attack, and the evaluation should therefore be based on operational experience.

Top-of-line corrosion can take place due to condensation of water in the top of the pipe in a stratified flow regime. Important parameters for such top-of-line corrosion are flow regime, operating temperature, condensation rate, CO_2 fugacity and content of organic acids. Top-of-line corrosion should be evaluated using models specifically made for this or using test data gathered under similar operating conditions. Top-of-line corrosion can also be influenced by the presence of H_2S.

Under flowing conditions flow-enhanced corrosion or erosion-corrosion can occur. Flow-enhanced corrosion will occur under high flow rates, as a result of accelerated mass transport of the reactants and reaction products. Many corrosion models consider the influence of flow-enhanced corrosion and such models should be used for prediction of corrosion rate under flowing conditions. At very high fluid velocities, even in the absence of solids, the liquid phase can be so energetic as to mechanically erode any protective scales or remove the protective inhibitor film in inhibited lines and cause erosion-corrosion. In the presence of solids, such mechanical erosion of the protective layers/films can occur at lower fluid velocities. In both cases, the consequences are more rapid material wastage rates than would be expected if simply summing predicted erosion and corrosion rates. This erosion-corrosion can occur even at low predicted sand erosion rates in fluids that are corrosive to the material under consideration. More information on sand erosion is provided in 6.5.

6.2.2.3 Microbiologically induced corrosion

Microbiologically induced corrosion (MIC) from sulfate-reducing bacteria, or other bacteria such as acid-producing bacteria and nitrate-reducing bacteria, can lead to high local corrosion rates. Low flow velocities in pipelines increase the likelihood of MIC.

MIC is likely to occur in dead legs and other settling locations. Cleaning and chemical treatment can be used to prevent MIC. The need for sampling points and biocide injection facilities should be considered in design.

NOTE MIC is normally caused by sessile bacteria in contact with carbon steel rather than planktonic bacteria.

6.2.2.4 Sulfide stress cracking (SSC)/stress corrosion cracking (SCC) caused by H_2S

The evaluation and use of materials in conditions containing H_2S, where cracking including hydrogen-induced cracking (HIC) is possible, shall follow the requirements given in ISO 15156 (all parts). This evaluation should include the potential for future changes in reservoir H_2S content, especially if water injection is planned. Dehydration of gas or use of corrosion inhibitors should not relax the requirement to use H_2S-resistant materials if the conditions are otherwise categorized as sour in accordance with ISO 15156 (all parts).

6.2.2.5 Alkaline stress corrosion cracking

Alkaline environments containing compounds such as amines, caustic or carbonates can cause alkaline stress corrosion cracking (ASCC) of carbon steels, especially where there is the potential to concentrate these compounds, e.g. in the presence of crevices or evaporation.

Typical mitigation measures may include heat treatment after welding or forming, use of protective coatings, CRA or non-metallic materials.

NOTE Reference can be made to NACE RP0403[26] for guidance on caustic cracking or to API RP 945[18] for guidance on amine cracking.

6.2.2.6 Stress corrosion cracking without H_2S

Occasionally, internal SCC can occur in SS in the absence of H_2S and dissolved oxygen in oil and gas production systems. This is due to local process conditions causing water evaporation and deposition/concentration of chlorides in high salinity waters and at high temperatures. Systems where this can occur should be designed with fresh wash water injection facilities to prevent concentration of chlorides or resistant materials should be used.

6.2.3 Corrosion parameters

6.2.3.1 General

Parameters considered in a corrosion evaluation should include the following, as appropriate:

a) CO_2;

b) H_2S;

c) temperature;

d) organic acids;

e) oil/gas properties and water content;

f) oxygen;

g) elemental sulfur;

h) mercury (Hg);

i) production chemicals.

Annex A gives an example of the contents of the design basis for materials evaluation in hydrocarbon systems. It should be noted that the design basis should consider the possibility of changing operational conditions over a facility's design life, such as increasing water cut and reservoir souring over the design life of the facilities.

6.2.3.2 CO_2 and H_2S contents

Most CO_2 corrosion prediction models for carbon steel require input in terms of CO_2 fugacity. The CO_2 partial pressure in the gas phase should be used, which can be derived from flash calculations for the actual conditions. For piping/pipelines transporting wet hydrocarbon liquids (oil and condensate), the CO_2 content and the total pressure for the last separation stage should be used to estimate the corrosion rate. For lines carrying wet gas, the CO_2 fugacity is a function of the lines operational pressure and temperature.

To compensate for non-equilibrium conditions downstream of a pressure reduction, the corrosion rate found for the conditions upstream of a pressure reduction may be assumed.

For evaluation of cracking including HIC in H_2S-containing service, the partial pressure is normally used. The H_2S content in the gas phase should be used, which should be derived from flash calculations for the actual conditions.

Corrosion and H_2S cracking resistance vary with pH which is difficult to measure accurately since it has to be done under actual pressure and temperature. Therefore, pH should be calculated by a suitable model or by using ISO 15156. The calculation should be based on CO_2 and H_2S fugacities at the actual pressure, temperature and composition of the produced water. The methodology used should be agreed with the end user.

If a full water analysis is not available, the values used for corrosion and cracking evaluations should be agreed with the end user. The following values may be used for an initial evaluation:

— for solutions representing condensed water, as in gas-producing wells, the pH should be calculated based on the actual temperature and CO_2/H_2S fugacity for pure water; with no data available, a pH of 3,5 and a chloride content of 600 mg/l may be used (1 000 mg/l of NaCl) (this corresponds to a CO_2 fugacity of 1,0 MPa);

— for solutions representing formation water, as in oil-producing wells, a pH of 4,5 and a chloride content of 100 000 mg/l may be used (165 000 mg/l of NaCl).

When calculating the pH used in CO_2 corrosion predictions in gas production environments with condensing water, it should be evaluated if the water contains sufficient corrosion products, as they act to increase pH and reduce corrosivity. Downstream of CRA piping or equipment, such as gas coolers, it should be assumed that the water is free from corrosion products and potentially corrosive to carbon steel.

6.2.3.3 Temperature

Resistance to corrosion and SCC vary with temperature for carbon steels and CRAs. Sensitivity calculations or evaluations can be necessary to determine the most critical temperature range.

The possibility of periods involving higher temperatures, such as heat tracing, steam-out or solar radiation, should be considered in the corrosion evaluation.

Temperatures during construction, transportation, storage and installation should also be considered.

6.2.3.4 Organic acids

Organic acids increase the corrosivity of the produced fluids and their presence should be included in the corrosion evaluation for carbon steel.

NOTE The corrosivity due to organic acids is determined by the presence of undissociated organic acid, as opposed to organic acid salts. Hence, it is essential to consider the complete water chemical analysis.

6.2.3.5 Oil/gas properties and water content

Flow effects and liquid properties can keep the water entrained in the oil phase. This may prevent contact between the separated water and the steel surface. However, the potential inhibition effect of the oil phase should be used with caution. Laboratory testing can be utilized to determine if oil can have inhibiting properties.

A gas is considered dry when the water dew point at the operational pressure is at least 10 °C lower than the minimum operating temperature for the system. Such systems are not subject to electrochemical corrosion and no corrosion prediction is required.

NOTE Gas dehydration in glycol contactors leads to condensation of a glycol/water mixture in dry gas pipelines [typically less than 10 % (mass fraction) water]. Even though this does not represent any corrosion threat for the pipeline, large quantities of corrosion products can accumulate in the pipeline. These products can cause problems, since the corrosion products can arrive at the receiving facility as “black dust” during pigging operations.

If the export gas specification is less than this dew point limit or there is a possibility of transient periods of operation with insufficient or no dehydration, this should be considered in the corrosion evaluation.

6.2.3.6 Oxygen

Oxygen is not normally present in production streams. Chemicals for injection may contain oxygen and the need for controlling the oxygen content should be evaluated.

The risk of oxygen ingress is likely in systems operating under vacuum and when an inert gas is used as blanket gas. The purity of the inert gas is a parameter that should be included in the corrosion evaluation. Oxygen ingress due to imperfect seals in pumps and compressors should be considered.

NOTE The fact that the internal system pressure exceeds the external pressure does not alleviate this risk, because the partial pressure of oxygen in the atmosphere will most likely exceed the internal partial pressure of oxygen. Hence, a driving force for oxygen ingress exists in spite of the negative absolute pressure difference.

6.2.3.7 Elemental sulfur

Elemental sulfur can be present in natural gas, and it can precipitate when the pressure or the temperature is reduced. Elemental sulfur also forms if H_2S comes into contact with oxygen, e.g. as a result of oxygen ingress into the process systems.

Elemental sulfur is extremely corrosive to carbon steel as well as to some CRA materials. If elemental sulfur is present, tolerant materials or chemical treatment should be used. ISO 15156-3 gives guidance on sulfur-resistant materials.

6.2.3.8 Mercury

Effects of the presence of mercury in produced fluids or gas should be considered in selection of materials. Limits are not well established and therefore mercury-bearing streams should not use copper-, titanium- or aluminium-based alloys for any components.

NOTE Mercury and associated mercury compounds can be detrimental to certain materials. Mercury can occur naturally as a contaminant in well-production fluids or gas. It is necessary to recognize the possible presence of mercury at the earliest possible stage of design, in order to avoid specification of potentially susceptible materials. It is generally accepted that damage can occur only when mercury is present as liquid. Attack can be by amalgam formation or by liquid metal embrittlement.

6.2.3.9 Production chemicals

Chemicals injected into the process stream or downhole can be potentially corrosive, and this should be considered in the corrosion evaluation. The selection of the actual chemicals is normally performed after all materials are selected and installed. Testing should be required to qualify the chemicals with respect to compatibility with all materials, including organic materials in seals, pipes, coatings and liners.

6.3 Internal corrosion in injection systems

The most relevant corrosion mechanisms for injection of gas, produced water and aquifer water are the same as for hydrocarbon carrying systems covered in 6.2 and the corrosion evaluation should be made accordingly.

For de-aerated seawater, there are two possible corrosion mechanisms, oxygen corrosion and bacterial corrosion. A typical residual oxygen concentration for unchlorinated de-aerated seawater under normal operation is 20 mg/m^3 to 50 mg/m^3, but can be significantly higher during upset conditions and during chemical treatments. The actual concentration of oxygen varies with type of de-aeration system. To select materials effectively, the assumed oxygen content in the seawater should be agreed with the end user.

6.4 Internal corrosion in utility systems

A corrosion evaluation should be carried out to determine the general corrosivity of the internal fluids under the applicable design conditions and for the materials under consideration.

Evaluation of corrosivity in water-carrying systems should include parameters such as:

- maximum design/operating temperature;
- flow rate (stagnant, intermittent or continuously flowing).

In addition, chloride concentration (salinity), water chemistry and pH should be considered for fresh-water systems, and residual chlorine and operating mode (dry or wet when not in use) should be considered for seawater systems.

Residual chlorine level and temperature are the two most important parameters that affect the corrosion performance of passive materials. Seawater systems are often continuously chlorinated to prevent bio-fouling; a typical residual chlorine level for continuous use is 0,3 mg/l to 0,7 mg/l. Initial start-up without chlorination for a period of two weeks can be used to promote build-up of the passive layer.

NOTE Biofouling treatment packages containing copper additives and much lower residual chlorine levels can be specified as an alternative. This can reduce the corrosion threat.

Materials such as CuNi 90/10 and NiAl bronze are sensitive to the flow rate; see EEMUA 194[24].

Corrosion evaluations of utility systems not particularly addressed below should be made to the extent deemed relevant for each project.

6.5 Sand erosion

In cases where the potential exists for significant sand production, a sand erosion evaluation should be carried out. The evaluation should include sand prediction studies in the reservoir to provide information regarding reservoir sanding potential, as well as an evaluation of possible erosion damage. Erosion-prediction models can be used to evaluate the likelihood of erosion damage. The model used should be specified by or agreed with the end user. Even where the predicted erosion rate is low, the potential for synergistic erosion-corrosion should be considered as discussed in 6.2.2.2.

Evaluation of sand-removal equipment, evaluation of safe operating conditions, monitoring of sand production, setting of operational alarms and confirmation of the integrity of the production systems are also important issues for consideration as part of the overall sand management strategy for each facility.

6.6 External corrosion

6.6.1 General

General and localized external corrosion including SCC and hydrogen stress cracking (HSC) should be considered.

The external environment affects the selection of materials and the method(s) chosen to provide protection from external corrosion. Typical environments to be considered in the evaluation of external corrosion are classified in ISO 12944-2.

In addition to guidelines and criteria for steel structures design given in ISO 12944-3, the following items should be considered in order to avoid premature corrosion and degradation of coating, or structures, or both:

- normal atmospheric conditions (marine or non-marine);
- contact with soil, or pipe supports, or both;
- ambient temperature and maximum operating temperature;
- presence of external insulation, with or without heat tracing;
- solar heating;
- presence of water, such as flooding by deluge systems.

Guidelines for suitable coating systems as a function of design life and corrosivity category are considered in ISO 12944-5.

6.6.2 External marine atmospheric environments

The external marine atmospheric environment contains water and chloride salts. Carbon steels will corrode under such conditions. CRAs can suffer from corrosion, including SCC. Welds are particularly vulnerable to SCC due to residual stresses and geometric stress concentrations.

Table 3 presents typical maximum operating temperature limits that have been applied to avoid chloride-induced SCC for some uncoated SS. The lower temperature limit represents cracking in the “worst case situation” at high tensile stresses and at concentrated chloride salt levels experienced when salt containing water is continuously evaporated. The lower temperature limits are based mostly on laboratory experiments. Many end users have used the higher temperature limits indicated in Table 3. Extensive field experience over many years shows that very few SCC failures have occurred on uncoated and uninsulated pipes when these higher temperature limits were used.

Table 3 — Typical temperature limits for uncoated SS in marine atmospheric environments

Material type	Grade	Maximum operating temperature limits[ab] °C
Austenitic SS	Type 316	50 to 60
	Type 6Mo	100 to 120
Duplex SS	Type 22Cr	80 to 100
	Type 25Cr	90 to 110

[a] The materials may be used at higher maximum operating temperatures at marine installations within areas with full heating-ventilation-air conditioning (HVAC) control.

[b] Nickel-based and titanium alloys do not have established temperature limits in marine environments, but are recognized to be more resistant than stainless steels.

Pitting and crevice corrosion can occur on CRAs at temperatures lower than those given in Table 3. A coating may be applied to prevent such corrosion. This is particularly the case under insulation and under pipe supports and clamps. Coating to prevent SCC should be used with caution (see 8.3).

Nickel-, titanium- and copper-based alloys are in general considered to be immune to SCC in marine environments.

6.6.3 External non-marine atmospheric environments

External non-marine atmospheric environments can contain water, but normally very low chloride content.

NOTE Non-marine environments can be corrosive depending on the local atmospheric conditions.

The potential for external corrosion in non-marine, arctic and desert environments varies depending on geographic location and industrial pollution. Consequently, it is necessary to evaluate the requirements for painting on a case-by-case basis. Guidelines for defining environments in terms of external corrosivity are considered in ISO 12944-2.

6.6.4 Buried and submerged installations

The external protection of buried or submerged structures is usually achieved by a combination of external coatings and cathodic protection. The evaluation for corrosivity categories may be difficult to define, but some guidelines are given in ISO 12944-2. For external corrosion mechanisms and protection of buried pipelines, see ISO 13623.

It has been shown that some materials are susceptible to HSC if they are subjected simultaneously to stresses and cathodic protection resulting in potential hydrogen charging of the cathodic component. Depending on metallurgical condition, some CRAs, such as UNS S17400, UNS N05500 and duplex stainless steel, can be susceptible to HSC while cathodically protected. To minimize such risk in these alloys, they should be used in a heat treatment condition compliant with ISO 15156/NACE MR0175. DNV-RP-F112[21] is a guideline for avoiding HSC in duplex stainless steel.

6.6.5 Corrosion under insulation

Corrosion under insulation (CUI) and fireproofing is a major integrity threat, particularly to installations located offshore and at coastal locations. The problem is generally associated with carbon and low alloy steels, but austenitic stainless steels and duplex stainless steels should also be considered. The CUI integrity threat is influenced strongly by the external material surface temperature, presence of chlorides, and local condensation conditions on the metal surface.

Specification of marine service external coating systems is essential in mitigation of CUI when such a threat is identified. Additionally, careful selection of external insulation systems and sealing systems to minimize water entry needs to be considered in the design of the insulation system. Guidelines for selection of external coatings and insulation systems for austenitic stainless steel and carbon steel are given in NACE RP0198[25]. Other guidelines are given in EFC Document No. 55[23].

The design should also consider the insulation integrity inspection requirements in service.

6.7 Polymeric materials

The selection of polymeric materials, including elastomeric materials, should be based on an evaluation of the functional requirements for the specific application. The materials should be qualified according to procedures described in applicable material/design codes.

Dependent upon application, the following properties should be included in the evaluation and documented:

- thermal stability and ageing resistance at specified service temperature and environment;
- physical and mechanical properties;
- thermal expansion;
- swelling and shrinking by gas and by liquid absorption;
- gas and liquid permeation;
- decompression and creep resistance at high temperature and pressure;
- resistance to thermal cycling and dynamic movement;
- low-temperature flexibility;
- chemical resistance;
- fire resistance.

NOTE ISO 23936-1 gives guidelines for selection and qualification of thermoplastic polymers in contact with media related to oil and gas production, and also provides guidance on maximum and minimum allowable temperatures.

6.8 Glass-fibre-reinforced plastic

For systems where glass-fibre-reinforced plastic (GRP) may be applied, epoxy and vinyl ester resins should be evaluated as alternatives for vessels and tanks; see also ISO 14692 (all parts). Polyester resin may be used in tanks for seawater and open-drain services. For other than seawater and fresh-water services, the fluid compatibility should be evaluated and documented in accordance with 6.7.

The temperature and aggressiveness of the medium can require that the GRP be lined with a thermoplastic barrier/liner, e.g. tanks for hypochlorite systems.

6.9 Mechanical properties and material usage limitations

6.9.1 General

Mechanical properties such as yield strength, tensile strength, hardness and impact toughness should be considered in the selection of materials. In addition, for parts of the production system that can operate at low temperatures or experience low temperatures during blow-down conditions, the equipment can still be cold when it is repressurized or constrained, causing thermal cooling stresses and thus requiring material toughness to be sufficient to prevent brittle fracture under these transient conditions. Material properties based upon the minimum and maximum design metal temperatures and wall thicknesses shall be in compliance with specified design codes.

Exposure temperatures during intermediate stages, such as manufacturing, storage, testing, commissioning, transport and installation, should be considered when specifying the minimum design temperature.

The following guidelines for design and limitations in mechanical properties should apply for materials selection:

— the specified minimum yield strength (SMYS) of carbon and low alloy steels intended for welding should not exceed 560 MPa. A higher SMYS may be specified, provided that documentation showing acceptable properties with respect to weldability and the properties of the base material, heat-affected zone and weld metal is presented;

— usage limitations for materials in H_2S-containing environments shall be in accordance with ISO 15156-2 and ISO 15156-3;

— free-machining steel grades should not be used;

— austenitic SS castings with PREN $\geqslant$ 40 should not be used for butt weld components due to risk of micro cracking in the heat-affected zone (HAZ) in weldments;

— the hardness of weld and HAZ of any steel grade should not exceed 350 HV10 for non-H_2S-containing service;

— titanium should not be used for hydrofluoric acid or anhydrous methanol with water content less than 5 %.

6.9.2 Submerged installations

For submerged components that can be exposed to cathodic protection including fasteners, the following guidelines are given:

— the actual yield strength of any steel grade should not exceed 950 MPa;

— the hardness of any components in any steel grade should not exceed 35 HRC or 328 HB;

NOTE 1 For conversion of hardness numbers, ISO 18265 is used.

— for components made with duplex stainless steel, compliance with DNV-RP-F112[21] should be specified (see 6.6.4);

— the hardness of components in nickel-based alloys should not exceed hardness values stated in ISO 15156-3;

— titanium-based alloys should not be used for applications involving exposure to cathodic protection.

NOTE 2 Practical design solutions, including application of a suitable electrical isolation of the integrated titanium component, can be agreed with the end user.

7 Materials selection for specific applications and systems

7.1 General

Typical materials selection for specific systems and areas are given in Tables 4 to 12. However, this does not exclude the use of other materials.

The chemical compositions of typical alloys used for oilfield developments are listed in Table C.1.

7.2 Oil and gas production and processing systems

7.2.1 General

For wet hydrocarbon processing involving flowlines and pipelines, carbon steel should be evaluated for corrosion performance as the base-case materials selection option. This evaluation may include successful operating experience, or may be based on the fact that the calculated annual corrosion rate, taking into account protective measures, is less than the corrosion allowance divided by the specified design life.

CRA should be evaluated against carbon steel when this is considered appropriate in the materials selection process.

For wet gas/condensate processing, the corrosivity of the wet gas to carbon steel can be very high due to the low pH of the condensed-water phase. Additionally, corrosion inhibition might not be practical in these systems, and the appropriate material choice is either carbon steel with a corrosion allowance or a CRA.

For dry gas/oil/condensate systems, carbon steel can be selected with no requirements for internal corrosion control. However, a corrosion allowance may be required if periods of wetness are envisaged during the construction/commissioning phases or during the operational phase.

7.2.2 Heat exchangers

Materials selection for heat exchangers requires the following special considerations:

- corrosion allowances are not generally available for carbon steel tubes (shell-and-tube type)/plates (plate type), and thus it is necessary to consider CRA for many applications in which carbon steel is chosen as a piping material;
- the design of the heat exchanger, e.g. shell-and-tube, air coolers, plate coolers, strongly influences the materials selection;
- the materials selection considerations should be very specific, e.g. severe crevicing conditions in hot seawater;
- ingress of water from deluge systems between plates in bolted plate heat exchangers should be considered;
- high surface temperature creates a risk of SCC or crevice corrosion of the plate or tube material on both the crude and hot water sides of crude oil heaters or gas coolers.

7.2.3 Wellhead, production and process systems

Typical materials selection for production and process system are given in Table 4. Closed drain and fuel-gas systems are listed under utility systems in this International Standard.

Pressure vessel materials for oil/gas/water separation and gas-treating systems should be selected based on the same corrosivity criteria as for hydrocarbon piping systems. Pressure vessels manufactured in solid CRAs, internally CRA clad or weld overlaid, do not need additional internal corrosion protection systems. To eliminate the risk of external SCC of a pressure vessel in solid stainless steel, it is advantageous in some cases to use internally CRA clad carbon steel pressure vessels.

Materials for valve internals should have wear resistance, or abrasion resistance, or wear and abrasion resistance, for use in fluid services that contain suspended solids. The internals should have the same or better corrosion resistance than the body, and should be corrosion resistant to the internal service conditions.

Table 4 — Typical materials for hydrocarbon production and process systems

Equipment		Materials
Wellhead equipment/Xmas trees		— Carbon steel or low alloy steel with or without alloy 625 weld overlay covering seal areas and other fluid-wetted areas — Type 13Cr steel with/without alloy 625 overlay at sealing surfaces
Piping		— Carbon steel or low alloy steel with or without CRA clad — Type 316; type 22Cr duplex; type 25Cr duplex; type 6Mo
Valve body/bonnets		— Carbon steel or low alloy steel with or without alloy 625 weld overlay — Type 13Cr; type 316; type 22Cr duplex; type 25Cr duplex; type 6Mo
Valve internals	Surface installations and subsea retrievable	Type 13Cr steel or alloys with better corrosion resistance than the body
	Subsea installations non-retrievable	Alloy 718 or alloys with equivalent or better corrosion resistance than the body
Vessels		— Carbon steel with and without internal organic coating or lining[a] — Carbon steel with CRA clad or weld overlay such as type 316, alloy 904, alloy 825 or alloy 625 — Type 316, type 22Cr duplex, type 25Cr duplex

[a] Sacrificial anodes may be required for pressure vessels made of carbon steel with internal coating or lining. The requirement for regular inspection and coating repairs should be accounted for in materials selection.

7.2.4 Flare systems

The typical materials selection for flare systems is given in Table 5.

Table 5 — Typical materials for flare systems

Equipment	Materials
Relief system, piping and vessels	Carbon steel, type 316; type 6Mo; alloy 904
Flare-tip assembly	UNS S31000; UNS S30815; alloy 800H; alloy 625

7.2.5 Produced water

There are several corrosion mechanisms that can occur in produced water systems. The materials selection is influenced strongly by operating experience.

Produced water systems can be complex, and oxygen contamination can occur, as described in 6.2.3.6. Seawater ingress from drain systems has also been reported. Some produced water systems can support bacterial activity, especially if the sulfate concentration is high, due to breakthrough of seawater from previous seawater injection. In such circumstances, microbiological corrosion is the main integrity threat for carbon steel. Oxygen ingress and MIC strongly influence the selection of corrosion control chemicals.

The typical materials for produced water systems are given in Table 6.

Table 6 — Typical materials for produced water systems

Equipment	Materials
Wellhead equipment/Xmas trees (for re-injection systems)	Carbon or low alloy steel internally clad with alloy 625 on all sealing surfaces or on all wetted surfaces
Piping	Carbon steel; type 316; type 22Cr duplex; type 6Mo; GRP
Vessels and equipment	Carbon steel with and without internal organic coating[a]; type 316; type 22Cr duplex
Pumps[b]	Type 316; type 22Cr duplex; type 25Cr duplex
Valve body/bonnets	Carbon steel; type 316; type 22Cr duplex; carbon steel internally clad with alloy 625
Valve internals[c]	Type 316; type 22Cr duplex, or alloys with equivalent or better corrosion resistance

[a] Sacrificial anodes should be required for pressure vessels made of carbon steel with internal coating or lining. Regular inspection and coating repairs should be specified.

[b] For details on pump materials, see ISO 13709.

[c] Type 13Cr should not be used in produced water service.

7.3 Injection systems

7.3.1 General

Injection systems involve injection of water or gas into the sub-surface for disposal or stimulation purposes.

Water injection systems include injection of de-aerated seawater, untreated seawater, chlorinated seawater, produced water, aquifer water, and combinations and mixing of different waters.

Brackish water should be considered as seawater.

NOTE Aquifer water comes from an underground layer of water-bearing, permeable rock from which ground water can be extracted. This water can be used for injection into oil-bearing reservoirs.

7.3.2 De-aerated seawater

Typical materials for systems carrying de-aerated seawater are listed in Table 7.

7.3.3 Aerated seawater

Typical materials for use in untreated and chlorinated seawater injection systems are listed in Table 8. In Table 10 typical maximum operating temperature limitations in chlorinated seawater with crevices for specific material grades are specified.

7.3.4 Produced water and aquifer water

The requirements for produced and aquifer water injection systems are the same as for produced water systems; see 7.2.5.

Nitrate injection should not be used for restraining sulfate-reducing bacteria activity in carbon steel produced water systems.

Aquifer water may be used as injection water. It can contain a high concentration of dissolved CO_2 which should be taken into account when evaluating corrosivity.

The effects of combined seawater and produced water injection should be considered with respect to corrosion and scaling effects. The corrosion rates can be higher than expected from simple CO_2 and O_2 corrosion models. The risk of MIC can be substantial and should be considered in the design.

7.3.5 Gas injection systems

The typical materials selection for dry gas injection systems is carbon steel. If the gas is not dehydrated, the system can be treated as a production system (wet gas).

Table 7 — Typical materials for de-aerated seawater systems

Equipment	Materials
Wellhead equipment/Xmas trees	Carbon or low alloy steel internally clad with alloy 625 on all sealing surfaces or on all wetted surfaces
Piping	Carbon steel; GRP; type 316; type 22Cr duplex
De-aeration tower	Carbon steel with internal organic coating plus cathodic protection in the bottom section
Pumps[a]	Type 316; type 22 Cr duplex; type 25Cr duplex
Valve body/bonnets	Type 316; type 22Cr duplex
Valve internals[b]	Type 316; type 22Cr duplex, or alloys with equivalent or better corrosion resistance

[a] For details on pump materials, see ISO 13709.

[b] Type 13Cr should not be used in produced water service.

Table 8 — Typical materials for untreated seawater systems

Equipment	Materials
Wellhead equipment/Xmas trees	Carbon or low alloy steel internally clad with alloy 625 on all wetted surfaces
Piping	GRP; type 25Cr duplex; type 6Mo; CuNi 90/10[a]; titanium grade 2
Vessels	Carbon or low alloy steel[b] with internal organic coating or lining in combination with cathodic protection; GRP; type 6Mo; type 25Cr duplex
Pumps	Type 25Cr duplex
Valve body/bonnet	Carbon or low alloy steel clad with alloy 625; type 25Cr duplex
Valve internals	Type 25Cr duplex or alloys with equivalent or better corrosion resistance

[a] CuNi 90/10 is not compatible with CRAs or more noble materials with respect to galvanic corrosion.

[b] Carbon steel clad with CRA may be used as alternative to solid CRA.

7.4 Utility systems

7.4.1 General

The materials selection guideline for utility systems includes fuel gas, open drains, closed drains, water services, chemicals, air and nitrogen systems.

Many utility systems contain fluids that are not or only mildly corrosive. Therefore, the integrity of the systems is generally not at risk, but it should be considered that even small amounts of corrosion products may result in unacceptable contamination.

7.4.2 Fresh-water systems

Potable water, demineralized water, de-ionized water and desalinated water are considered as fresh water. The chloride concentration is normally less than 100 mg/l.

Typical materials for handling fresh water are listed in Table 9.

Table 9 — Typical materials for handling fresh water

Equipment	Material	Typically applied maximum internal temperature °C
Piping, valves, vessels, heat exchangers and tanks	Type 316	60[a] to120
Piping, vessels, heat exchangers and tanks	CuNi 90/10	120[b]
Valves	Al-bronze	120[b]
Piping	Copper	120[b]
Piping, vessels and tanks	GRP (epoxy resin)	95
Piping, vessels and tanks	GRP (polyester resin)	40
Piping, vessels and tanks	GRP (vinyl ester resin)	80[c]
Piping, vessels and tanks	Epoxy-coated carbon steel	95[c]
Piping	Carbon steel HDG	50
Piping and tanks	PVC	70[c]
Piping and tanks	PE	60[c]
Piping and tanks	PP	90[c]

[a] The chloride concentration should be kept below 200 mg/l up to 60 °C. For higher temperatures, the chloride should be limited to lower concentrations to prevent internal pitting corrosion that can occur on type 316. A commonly used maximum operating temperature for uncoated type 316 is 50-60 °C in marine atmospheric environment, due to risk of external SCC (see 6.6.2 and 8.3).

[b] Copper and copper nickel alloys should be used only with potable water in the pH range of 6 to 9. For temperatures higher than 60 °C, the ratio of HCO_3/SO_4^{2-} should be greater than 1 to avoid pitting.

[c] The actual maximum operating temperature for any specific non-metallic material should be determined by the end user with input from the material manufacturer.

7.4.3 Seawater carrying systems

In Table 10, typical materials for seawater-carrying systems are listed, with typically used maximum operating temperature for piping systems with crevices.

NOTE 1 Systems that are heat-traced or exposed to solar heating can be exposed to temperatures higher than those expected from process calculations.

NOTE 2 Untreated seawater is normally regarded as less corrosive than chlorinated seawater, but very few application limits have been established.

Table 10 — Typical materials for chlorinated seawater-carrying systems with crevices

Equipment	Material	Maximum operating temperature °C	Other limitations
Piping	PE[a]	60	
	Elastomer pipe[a]	70	
Piping, vessels	GRP (epoxy resin)[a]	95	Maximum velocity: 5 m/s
Piping, vessels, valves	Carbon steel with an internal non-metallic coating or lining with or without CP	Temperature is limited by the selected type of coating or lining	
Piping, vessels	Type 6Mo	20	Maximum residual chlorine concentration: 0,7 mg/l
Piping, equipment, valves	Alloy 625	30	
Piping, equipment, vessels, valves, pumps	Type 25Cr duplex	20	
Piping, equipment, valves, heat exchangers[b]	Alloy C276/C22	50	
	Alloy 686/59/C2000	60	
	Titanium grades 1 and 2	85	
Piping[c], heat exchangers[b]	CuNi 90/10	100	Maximum velocity: 2,5 m/s-3,5 m/s dependent on pipe diameter
Pumps and valves	NiAl bronze	75	Maximum velocity: 15 m/s
	Type 25Cr duplex	20	

[a] The actual maximum operating temperature and fire resistance properties for any specific non-metallic material should be determined by the end user with input from the material manufacturer.

[b] The final choice of heat exchanger material will be influenced by the cooling/heating medium and heat exchanger design.

[c] Stagnant conditions and coupling to SS, titanium and nickel alloys should be avoided.

Resistors or diodes to control the potential and currents in internal cathodic protection systems have been applied to increase the temperature limits for alloy 625, type 6Mo and type 25Cr duplex in components of chlorinated systems. Care should be taken to operate these systems correctly.

Threaded connections are regarded as very sensitive to crevice corrosion and should be avoided in CRA materials. Surface preparation (pickling and passivation) and start-up procedures can affect the risk of crevice corrosion if materials are applied in borderline conditions.

For plate and shell/tube heat exchanger applications with seawater on the shell side, severe crevice conditions exist and SS is generally not used. Titanium alloys are generally used for this service, while the use of copper or nickel-based alloys should be evaluated on a case-by-case basis.

HDG carbon steel is not commonly used for seawater systems, except for short design life (5 years to 10 years). If galvanized piping is specified for use in normally stagnant systems, e.g. fire-water systems, suitable measures, such as frequent fresh water flushing of the system, should be implemented to avoid plugging of sprinkler/deluge nozzles. Galvanizing should be performed on completed welded spools to ensure that the entire internal surface including the welds is coated.

Graphite containing gaskets should not be used in metallic seawater piping systems.

7.4.4 Other utility systems

Materials selection for these systems is given in Table 11, with amendments as given below. This listing does not exclude other materials to be used, but lists the most typically used materials.

For closed-loop heating and cooling systems, fresh water or fresh water with 30 % (mass fraction) triethylene glycol (TEG) is used as cooling/heating medium. Proprietary hot-oil fluids are also often used as heating medium and are considered non-corrosive to carbon steel.

Carbon steel has been used with success in TEG systems, but for heat exchangers and other critical components in these systems, type 316 can be a good alternative to carbon steel. Galvanic corrosion between carbon steel and type 316 is not expected. For carbon steel, it is essential to specify a suitable chemical treatment, such as corrosion inhibition, or pH control, or both, to ensure that the system is protected.

Table 11 — Typical materials for utility use

Service	Equipment	Materials	Notes
Open drain	Piping	Non-marine: carbon steel HDG; PE; GRP Marine: GRP; carbon steel; type 25Cr duplex	—
Closed drain	Piping	Carbon steel; type 316; type 22Cr duplex; type 25Cr duplex; GRP	—
Sewage	Piping	Type 316; GRP; polyethylene	—
Jet fuel	Piping	Type 316	—
Dry fuel gas and diesel	Piping	Carbon steel; type 316 or other SS (where cleanliness is required)	—
	Tanks	Carbon steel; GRP	a
Instrumentation	Tubing	Non-marine: type 316 Marine: type 316; UNS S31700; alloy 904; alloy 825; alloy C276; type 6Mo; type 22/25Cr duplex; titanium and Cu alloys	bc
	Junction boxes/cabinets	Non-marine: carbon steel painted or HDG with or without paint Marine: GRP; type 316	—
	Cable trays	Non-marine: carbon steel HDG; type 316 Marine: type 316; carbon steel HDG in fully HVAC controlled areas	—
HVAC ducts and units	Ventilation/air intake ducts	Non-marine: carbon steel HDG; type 316 Marine: type 316; carbon steel HDG may be used in living quarters and domestic areas	c
	Air-handling units	Non-marine: carbon steel HDG; type 316 Marine: type 316	—
	Cooling coils	Air and fresh water: type 316; copper-based alloys Seawater: titanium grade 2	b
Fire-fighting systems	Dry CO_2 systems	Carbon steel	—
	Deluge system	Carbon steel HDG; type 25Cr; type 6Mo; CuNi 90-10; titanium grade 2	bg
	AFFF piping	Type 316; GRP	c
	Fresh water/plant air/nitrogen	Non-marine: Carbon steel; type 316 Marine: Type 316	c
Lubrication and seal oil	Piping and vessels	Type 316; type 22Cr duplex; type 6Mo	c

Table 11 (*continued*)

Service	Equipment	Materials	Notes
Hydraulic oil/fluid	Piping and vessels	Carbon steel upstream filters; type 316	[c]
Instrument air	Piping	Carbon steel; carbon steel HDG; type 316	[c]
	Air receivers	Carbon steel; internally coated carbon steel; type 316	—
Inert gas/plant air piping	Piping and vessels	Carbon steel; type 316	[c]
Glycol	Piping and vessels	Carbon steel; type 316	—
Methanol	Piping and vessels	Carbon steel; type 316	—
Heating/cooling media	Piping and vessels	Carbon steel; CRA in heat exchangers	[d]
Miscellaneous chemical injection systems	Piping and vessels	GRP; type 316; type 6Mo; titanium grade 2	[ef]

[a] Diesel tanks in carbon steel should have a 3 mm corrosion allowance in the bottom section. In addition, the bottom and roof should be coated. Cathodic protection should be used only if corrosion products from the sacrificial anodes do not cause damage to the downstream equipment. No corrosion allowance is required for cathodically protected surfaces. Consider coating the entire diesel tank if corrosion products can be detrimental when stored product is utilized.

[b] Copper alloys should not be used in combination with stainless steel or nickel alloy in seawater systems.

[c] In a marine atmosphere, there may be a high risk for localized corrosion of type 316, in particular crevice corrosion under clamps. The use of alternative tubing material should be evaluated.

[d] Fresh-water heating and cooling media are normally treated with a corrosion inhibitor and an oxygen scavenger. In a freezing environment, it is normally mixed with TEG.

[e] The combination of chemical and material should be considered in each case. Titanium grade 2, GRP or chlorinated polyvinyl chloride should be used for hypochlorite systems.

[f] Typical chemicals include corrosion inhibitor, scale inhibitor, anti-foam, de-emulsifier wax, biocide and oxygen scavenger.

[g] Systems made in carbon steel HDG may suffer from nozzle blocking.

7.5 Pipelines and flowlines

In principle, there are no differences between pipelines/flowlines and other systems with respect to corrosion evaluation and materials selection. However, since the material costs for these items can represent a significant part of the total investment for a project, they should be evaluated separately. The material selected for a pipeline/flowline can also influence the installation method, or vice versa.

Typical materials for pipelines/flowlines in different service conditions are listed in Table 12.

Table 12 — Typical materials for pipelines/flowlines dependent on type of service

Type of service	Materials
Hydrocarbon production	Carbon steel with or without chemical treatment
	Flexible pipe with carcass in type 316 or duplex stainless steel
	Carbon steel, internally clad/lined with type 316, alloy 825 or alloy 625
	Type 22Cr
	Type 13Cr with low carbon content
Wet hydrocarbon gas (not dehydrated)	Same materials as for unprocessed hydrocarbon production
Dry gas (dehydrated)	Carbon steel
Stabilized or partly stabilized oil or condensate	Carbon steel with or without corrosion inhibitor
De-aerated seawater[a] and produced water for injection	Carbon steel with chemical treatment
	Carbon steel with organic coating or lining
	Flexible pipes with carcass in type 316 or duplex stainless steel

[a] Several failures due to bacterial corrosion have been reported in carbon steel subsea injection flowlines transporting de-aerated seawater. The corrosion that occurs in the 6 o'clock position in the pipe is caused by sulfate-reducing bacteria. The attack is very difficult to control and even with cleaning pigs and bacterial treatment, corrosion rates in the order of 1 mm/year have been experienced. Carbon steel with an internal organic coating/lining has been used with success and can be considered for water-injection pipelines. Alternatively, controlling injected de-aerated seawater chemistry to specified low oxygen levels and including a biocide or nitrate treatment can permit the use of unlined carbon steel. Nitrate improves the corrosion control and, in addition, reduces the reservoir souring and, hence, the H_2S production.

8 Corrosion control

8.1 Chemical treatment

Carbon steel, with one or several corrosion control measures as described in this clause, is the material most commonly used in production and processing facilities. Common methods of chemical treatment are the use of film-forming inhibitors, oxygen scavengers, biocides, anodic inhibitors and pH stabilizers.

If the imposition of environmental requirements by national regulators or by the end user is likely, then the types of corrosion inhibitors suitable for use can be limited. Environmental requirements for the use of corrosion inhibitors should be agreed with the end user.

Application and monitoring of chemical treatment is mainly an issue related to operation of the facility, but some issues should be addressed during materials selection. The remainder of this clause addresses chemical treatment only for corrosion control in production and processing systems.

Parameters that can strongly influence the feasibility of chemical inhibition are temperature, flow conditions, H_2S content and compatibility with other chemicals. For produced water systems, contaminants such as oxygen and MIC should also be considered. These parameters should be defined in the design basis.

There is limited experience relating to the effects of erosion in solids-containing systems where the system is corrosive and protection to carbon steel is provided by a corrosion inhibitor. The performance of the corrosion inhibitor can be affected by solids, both by physical removal of the corrosion inhibitor layer and by absorption of the inhibitor onto the solids, thus reducing the amount of inhibitor available to contact the metal surfaces.

The performance of inhibitors should be confirmed via laboratory testing. Actual field trials should be performed to test and optimize the dosing.

In deciding whether carbon steel combined with corrosion inhibitors can be applied for the actual system, the above parameters should be addressed and operating measures should be defined as a part of the materials selection process. It should be proven that a corrosion inhibitor can give satisfactory protection for the actual service conditions, either by relevant field experience or by laboratory testing. The models, data, test methods and acceptance criteria for application in this process should be agreed with the end user.

Corrosion inhibition to prevent CO_2/H_2S corrosion is not effective in mitigating top-of-line corrosion. Alternatively, periodic treatments such as spray pigging or batch treatment of concentrated corrosion inhibitor between two pigs should be evaluated.

NOTE 1 A common methodology is the use of the “inhibitor availability”. The inhibitor might not be available during start of the system or due to failures in the injection system. The inhibited corrosion rate is typically 0,1 mm/year (to be agreed with the end user).

In pipeline systems with only condensed water as the water phase and monoethylene glycol (MEG) as hydrate inhibitor, the corrosion can be controlled by pH stabilization in non-sour systems.

NOTE 2 pH stabilization means that an alkaline chemical is added to the MEG/water phase in order to increase the pH, reduce the solubility of iron ions and form protective surface films that reduce the corrosion to an acceptable rate. Examples of suitable chemicals are NaOH and amines. The MEG concentration is typically above 50 % (mass fraction). Due to the risk of scaling, the use of this treatment requires confirmation from the end user that no formation water will be produced.

NOTE 3 A pH-stabilizing chemical can also be used in combination with a film-forming inhibitor. The advantage of this method is that the pH of the water phase is stabilized to a level where scaling does not take place if formation water starts to be produced.

Issues such as inhibitor selection, compatibility with other chemicals, required concentrations and compatibility with non-metallic materials in the system should be addressed in due time to be ready before start of operation.

8.2 Internal corrosion allowance

An internal corrosion allowance is commonly used for carbon steel piping. The corrosion allowance should be added in response to expected internal corrosion. Each system should be evaluated and the selected corrosion allowance supported by corrosion evaluations. Possible corrosion during the construction, installation, preservation, start-up period and production upsets should be included, in addition to the expected corrosion during normal operation.

Commonly used corrosion allowances in piping systems are listed below:

a) 1,0 mm to 1,5 mm for non-corrosive service;

b) 3,0 mm for mildly corrosive service;

c) 6,0 mm for severely corrosive service.

For pipeline systems, a maximum internal corrosion allowance of 8 mm to 10 mm should be used as a general upper limit for use with carbon steel.

For pipelines with dry gas or non-corrosive fluids, corrosion during installation and testing prior to start-up should be considered.

Corrosion allowance for pipelines can have a great effect on installation cost, or pipeline operational life, or both, and detailed corrosion evaluations should support the selected allowances.

For corrosion allowances at galvanic connections, see 8.7.

8.3 Selection of internal and external coatings

External coating system selection for carbon steel should consider the design life, operating conditions and conditions during construction, transport, storage, commissioning and installation of the facilities.

Guidance on selection of coating system selection for different environments is given in ISO 12944-5 and surface preparation grades are defined in ISO 12944-4. Performance of the external coating system for carbon steel for offshore atmospheric and immersed conditions should generally conform to the requirements of ISO 20340.

For equipment specified in SS for use in marine atmosphere, an agreement with the end user should be reached when using external coatings to mitigate the external SCC and pitting corrosion. For these materials, special consideration should be given to coating selection, surface preparation and quality control during application of the selected coating system. It should be recognized that external coatings can have service lives that are shorter than the anticipated operational life cycle, and can require maintenance in order to minimize the threat of SCC of SS equipment or external corrosion of carbon steel.

Selection of internal coating for equipment should be performed on an individual basis due to the very wide range of possible service conditions. Additionally, some internal coating systems are specified in conjunction with cathodic protection, and for these systems it is necessary to evaluate the coating selection separately.

Galvanic corrosion between CRA equipment and the vessel wall in coated or lined carbon steel vessels should be addressed in case of coating damage. As a minimum, internal CRA support brackets should be painted. Other protection methods, such as cathodic protection, may be considered.

8.4 External splash zone protection

For structures and risers in splash zones, the selected coating should be designed to perform for the entire design life. Damage to the coating system should be expected. The corrosion allowance for risers should take into account exposure of bare steel to the environment for a realistic period for repair of coating damage. The corrosion allowance for carbon steel should be based on the predicted corrosion rate and design life, but should be a minimum of 6 mm unless otherwise specified.

Riser splash zone protection depends on the design and maintenance philosophy and on operating conditions. Suitable protection is dependent on the operating temperature. Thermal sprayed aluminium, polypropylene (PP), GRP and polychloroprene coatings are typical, but consideration should be given to the operating temperature. Polychloroprene with embedded granules/cuttings of CuNi alloy may be used as an antifouling layer over polychloroprene.

Splash zone protection for structures is typically provided by organic coatings or thermal sprayed aluminium.

8.5 Cathodic protection

8.5.1 Offshore

Structures and all retrievable components should have self-supporting CP systems designed for the specified design life. The cathodic protection design should be based on NACE SP0176[27] or DNV-RP-B401[22] for subsea structures and components, and ISO 15589-2 for offshore pipelines. Subsea installations should be protected against corrosion using paint or other coating systems combined with cathodic protection, unless otherwise agreed. Cathodic protection systems, or coating systems, or both, should be used for all metallic materials that are susceptible to seawater corrosion. An exception is made for components where it is impractical to obtain a reliable electrical contact with the anode system. Such components shall be made either of seawater-resistant materials or of carbon steel with a sufficient corrosion allowance for the required lifetime. Coating of components and structures limits the number of anodes required.

8.5.2 Onshore

The cathodic protection design for onshore buried pipelines should be as described in ISO 15589-1.

Cathodic protection should be considered for all other underground steel equipment, e.g. buried fire-water ring mains, but this should depend on the external corrosivity evaluation.

8.6 Corrosion protection of closed compartments

Internal corrosion protection is not necessary for completely closed and sealed dry atmospheric compartments in carbon steel structures. Dehumidification equipment can be applied in a closed or semi-closed atmospheric compartment to prevent humidity and corrosion.

For seawater-filled compartments which are completely sealed or have restricted seawater exchange, the need for CP or chemical treatment should be evaluated on a case-by-case basis. Parameters to be considered are structural loading, degree of exchange of seawater and ratio between volume and uncoated area.

Subsea structures and covers are often made of hollow components that will be filled with seawater, but the in-service utilization is normally low in terms of stress and fatigue. For such components having volume to uncoated area ratios less than 1 m^3/m^2, internal corrosion protection or corrosion allowance may not be necessary.

8.7 Connection of dissimilar materials

8.7.1 Piping systems

Galvanic corrosion can occur when dissimilar metallic materials are connected together in a conductive corrosive fluid. The potential difference between the two metals can cause a significant increase in corrosion rate of the less noble material. However, the extent of the galvanic corrosion risk is influenced strongly by such factors as the area ratio of the two metals, the cathode efficiency of the more noble metal, the conductivity of the electrolyte, oxygen content and temperature. It is necessary to evaluate all these parameters in the design of the facilities.

For hydrocarbon production and processing systems, galvanic corrosion is usually a consideration only between carbon steel and CRA. For those systems that involve anaerobic corrosive fluids in which the cathodic process is not driven by dissolved oxygen, there is a significant amount of operating experience worldwide to indicate that galvanic corrosion is generally not a concern, since very few cases have been reported. This is especially true for systems in which the internal corrosion of carbon steel is mitigated by corrosion inhibition. Consequently, for hydrocarbon production and processing systems, it is necessary to evaluate the requirements for designing for galvanic corrosion on a case-by-case basis.

In seawater systems, the galvanic couples that give rise to galvanic corrosion risk are well documented, and it is necessary to design the facilities to prevent galvanic corrosion. Flange connection is the preferred method of connecting dissimilar materials when there is a significant risk for internal galvanic corrosion.

Examples of techniques that can be used to mitigate the galvanic corrosion threat to dissimilar metal flanged interfaces in corrosive service are as described below.

- Install a flanged distance spool between the dissimilar metals, the length of which depends on the resistance path and pipe diameter. The distance spool material may be either a solid electrically non-conducting material (e.g. GRP) or a metal that is coated internally with an electrically non-conducting material, e.g. vulcanized rubber or polymeric coating. The metal of the distance spool piece can be specified as carbon steel if vulcanized rubber is used.

- Apply a corrosion allowance on the less noble metal or a sacrificial thick-walled carbon steel spool, which is designed for replacement at scheduled intervals.

- Install internal sacrificial anodes through access fittings near the interface, e.g. resistor-controlled cathodic protection for seawater systems.
- Apply electrical isolation of dissimilar metals; however, the risk of electrical continuity via pipe supports, decks and earthing cables should be evaluated.
- Reduce the cathode area by internally coating the more noble material in the couple.
- At critical interfaces between dissimilar metals in hydrocarbon production and processing systems, weld overlay of the flange face of the less noble material with a corrosion-resistant material may be considered.

8.7.2 Submerged installations

For submerged installations, the cathodic protection system prevents galvanic corrosion externally when the different materials are in electrical contact with each other and no special precautions are necessary.

8.7.3 Structural installations

The design requirements should be evaluated on a case-by-case basis for dissimilar metal combinations for structural applications, e.g. aluminium alloys to steel in marine atmospheric environments. It is also necessary to evaluate the practicality of any possible mitigation measures to avoid galvanic corrosion for each of these applications. For fasteners, it is important to ensure that they are the cathode in the dissimilar metal combination for such applications.

Similarly, if the environment is considered dry and non-corrosive or intermittently wetted, special precautions may be required and thus the materials selection requirements should be evaluated separately.

8.8 Sealing materials

All possible environmental conditions (including commissioning) should be considered when deciding on the optimum choice for ring gaskets. The seal ring shall as a minimum be resistant to the actual process environment.

For non-metallic seals, the possibility of crevice corrosion at the metal to non-metallic seal interface should be considered.

For raw seawater service, careful consideration should be given to ensure adequate crevice and galvanic corrosion resistance of materials at the expected operating conditions.

Material for sealing ring in ASME ring-type joints are normally selected to be of lower hardness than the flange material to assist seating and prevent permanent damage to the flange ring groove.

Sealing rings designed to operate within the elastic area, such as rings for hub connectors and compact flanges, should be made from a material with appropriate strength, ductility and toughness properties. Selection of the sealing ring material should also address any environmental limits imposed by other standards such as ISO 15156, if applicable.

8.9 Fasteners

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

The possibility of galvanic corrosion and the consequences of different thermal coefficients, if relevant, should be considered when dissimilar metals are used in fasteners and materials being connected.

Fasteners screwed into component bodies should be of material that is compatible with the body with respect to galling and corrosion properties.

In non-marine atmospheres, fasteners should be of a low alloy steel material coated with electrolytic applied zinc, HDG or polytetrafluoroethylene (PTFE) with anticorrosion pre-treatment.

In marine atmosphere, fasteners in low alloy steel should be HDG in accordance with ISO 10684 or ASTM A153[19], or coated with PTFE with anticorrosion pre-treatment such as cermet. Other pre-treatment coatings should be selected with caution with respect to corrosion. CRA fasteners should be chosen for connections in CRA materials in frequently wet environments such as extensive condensation or salt spray. Fasteners in low alloyed steel and SS may suffer from SCC and limitations to strength and hardness properties should be established and agreed with the end user.

Fasteners should be avoided in splash zone applications. However, when this is unavoidable, fasteners shall be made of seawater resistant material, e.g. alloy 625/725 or similar.

Fasteners in carbon steel or low alloy steel used with equipment installed subsea may be used in the black (uncoated) condition or coated for intermediate protection with electrolytic zinc, chemically converted coatings such as phosphates or PTFE (provided electrical continuity is verified). If cathodic protection cannot be ensured, fasteners shall be made of seawater-resistant material.

All plating materials shall be selected with due regard to national health, safety and environmental issues concerning manufacture and use.

Hydrogen embrittlement may occur on fasteners caused by hydrogen introduced from chemical cleaning related to coating operations, e.g. electrolytic plating and HDG. Baking in accordance with ISO 9588 should be performed for chemical cleaned fasteners with an actual tensile strength greater than 1 000 MPa or hardness greater than 31 HRC.

Fasteners submerged in seawater shall be resistant to hydrogen embrittlement. The material strength of carbon, low alloy and SS should therefore not exceed a SMYS of 725 MPa. Limitations for maximum hardness and actual yield strength are given in 6.9.2.

8.10 Weld overlay

In corrosive hydrocarbon systems, a CRA weld overlay with a minimum as-finished thickness of 3,0 mm may replace homogeneous CRA. Weld-overlay materials on carbon steel should be alloy 625 at sealing surfaces.

When alloy 625 and other nickel-based alloys are used as overlay metal, the maximum iron content at the finished surface should be 10 % (mass fraction).

8.11 Preferential weld corrosion

Care should be taken when choosing welding consumables to make sure that the corrosion resistance of the entire weld metal, HAZ and base metal are compatible with the environment. In addition, corrosion testing may be necessary to demonstrate adequate corrosion resistance.

8.12 Corrosion management

Carbon steel in combination with suitable measures to control corrosion is the base case material selection for most production facilities. Requirements for corrosion monitoring including locations for monitoring devices and sample points should be included as a part of detailed engineering. If subsea corrosion monitoring is required to ensure effective inhibitor performance, this should be included as a part of the selection of materials.

Detailed guidance on corrosion monitoring is given in Annex B.

Annex A
(informative)

Design basis for hydrocarbon systems

DATA FORM FOR DESIGN BASIS INFORMATION FOR HYDROCARBON PROCESSING FACILITIES	
Field name	
Contract name	
Contract No.	
Design life	

RESERVOIR DATA			
Reservoir pressure		Type of fluid	
Reservoir temperature		Completion fluid composition	
Bubble point pressure		Design value for CO_2 content (mole fraction, %)	
Reservoir fluid density		Design value for H_2S content (mole fraction, %)	
Sand and silt production		Mercury	
Wax		Elemental sulfur	
		Presence of free water	

FORMATION WATER CHEMISTRY									
Bicarbonate, HCO_3^- or total alkalinity									
Total amount of chlorides					Organic acids				
Na^+	K^+	Mg^{2+}	Ca^{2+}	Sr^{2+}	Ba^{2+}	$Fe^{2+/3+}$	Cl^-	SO_4^{2-}	

PRODUCTION WELLHEAD DESIGN CONDITIONS			
Shut-in pressure		Operation pressure	
Min. temperature		Operation temperature	
Max. temperature			

INJECTION WELLHEAD DESIGN CONDITIONS			
Type of injection fluid			
Max. O_2 content		Max. design pressure	
CO_2 content		Normal injection pressure	
H_2S content		Min. temperature	

DATA FORM FOR DESIGN BASIS INFORMATION FOR HYDROCARBON PROCESSING FACILITIES					
FLOWLINE DESIGN CONDITIONS					
Design temperature			H_2S content		
Inlet temperature			Condensed or formation water		
Outlet temperature			Flowline inner diameter		
Design pressure			Flow regime		
Inlet pressure			Oil production rate		
Outlet pressure			Gas production rate		
CO_2 content in gas phase			Water production rate		
General design basis for corrosion evaluations and materials selection					
Corrosion-prediction model (6.2.1)			Methodology or model for pH calculations (6.2.3.2)		
Erosion-prediction model (6.5)			Maximum operation temperature for use of uncoated SS in marine environments (6.6.2)	Type 316	
				Type 22Cr	
				Type 25Cr	
				Type 6Mo	
Recommended limitations in mechanical properties (6.9)	Mandatory		Temperature limits for non-metallic materials (7.4.2)		
	Informative				
Environmental requirements for use of corrosion inhibitors (8.1)			Corrosion inhibition test model and acceptance criteria (8.1)		
Design standard for CP (8.5.1)					

NOTE Users of this International Standard are permitted to copy this form.

Annex B
(informative)

Corrosion monitoring

B.1 General

Corrosion monitoring is part of a corrosion management system. Details on planning, identification of locations, data acquisition and reporting should, therefore, be included in the corrosion management system.

In general, the condition in systems needs to be monitored to provide a check on the effectiveness of corrosion-control methods adopted, and to provide the basis for remedial measures in the event of deficiencies being identified in these methods.

Monitoring can also give advance warning of potential problems in the event of operational upsets or changes in the corrosivity of the product fluids.

For hydrocarbon production systems, electrical-resistance probes and corrosion coupons are widely used to measure the corrosivity of the product, but might not necessarily reflect the actual corrosion rate for the associated pipe. Therefore, the interpretation of data collected from the probes and coupons should be performed by personnel experienced with corrosion monitoring. For some systems, monitoring of the actual pipe-wall thickness is an option. Other methods, such as linear polarization resistance (LPR) probes, galvanic probes, field signature monitoring (FSM) and acoustic methods, can also be used depending on the application.

Unless otherwise agreed, both a corrosion probe and a mass-loss coupon should be used for monitoring corrosion for pipelines and pipework in carbon steel to provide complementary data and an improved level of confidence. In addition, the monitoring data should be supplemented by operational data, i.e. analyses of production water and other fluids, to measure corrosion-inhibitor residuals, bacterial activity or to identify possible changes in the process that can influence the corrosivity of the product.

NOTE Sand-monitoring probes are intended to detect sand in the fluids and are not suitable replacements for corrosion-monitoring equipment.

Permanently installed monitoring systems for cathodically protected components should be considered when the components are not accessible for potential measurements. Monitoring may include both reference electrode(s) for potential measurement and monitored anodes for current determination.

For subsea flowlines and trunklines in carbon steel, where the local corrosivity cannot be evaluated by monitoring at the inlet or outlet of the flowline, permanent subsea monitoring equipment should be fully evaluated. Such an evaluation should also consider the possibility and frequency of inspection pigging and the criticality of the flowline.

B.2 Location of probes

Evaluation of the location and type of corrosion-monitoring equipment should be performed based on the probability of failure in combination with criticality of the system. Unless otherwise specified, location of the probes should be at the 6 o'clock position where water is likely to accumulate.

The monitoring probes/coupons should be installed at preselected locations in each pipe to be monitored, within a reciprocal distance of at least 0,5 m (two fittings). A retriever tool is required to install/retrieve the probes/coupons from equipment under production. Sufficient clearance for the tool shall be allowed for in the piping layout and when selecting the sensor location.

Annex C
(informative)

Chemical composition of some typical oilfield alloys

Table C.1 gives the chemical composition of some typical oilfield alloys.

Table C.1 — Chemical composition of some typical oilfield alloys

Group	Common name	UNS	Fe		C	Cr		Ni		Mo		N		W		Nb		Cu		Mn		Other elements
			min.	max.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	
			w_{Fe} %	w_{Fe} %	w_C %	w_{Cr} %	w_{Cr} %	w_{Ni} %	w_{Ni} %	w_{Mo} %	w_{Mo} %	w_N %	w_N %	w_W %	w_W %	w_{Nb} %	w_{Nb} %	w_{Cu} %	w_{Cu} %	w_{Mo} %	w_{Mo} %	w %
Stainless steel	13Cr	S41000	balance		0,150	11,5	13,5														1,00	
		S41425	balance		0,050	12,0	15,0	4,00	7,00	1,50	2,00	0,06	0,12							0,50	1,00	Si 0,05 max.
	F6NM	S41500	balance		0,050	11,5	14,0	3,50	5,50	0,50	1,00									0,50	1,00	Si 0,06 max.
	CA6NM	J91540	balance		0,060	11,5	14,0	3,50	4,50	0,40	1,00										1,00	
		S30815	balance		0,100	20,0	22,0	10,00	12,00			0,14	0,20								0,80	Si 1,40 to 2,00 Ce 0,03 to 0,08
		S31000	balance		0,250	24,0	26,0	19,00	22,00													Si 1,50 max.
	AISI 316L	S31603	balance		0,030	16,0	18,0	10,00	14,00	2,00	3,00										2,00	
	Type 6Mo	S31254	balance		0,020	19,0	20,0	17,00	18,00	6,00	6,50	0,18	0,22					0,50	1,00		1,00	
	Alloy 286	S66286	balance		0,080	13,0	16,0	24,00	27,00	1,00	1,50										2,00	Ti 1,9 to 2,35 V 0,10 to 0,50 Si 1,0 max.
	22Cr duplex	S31803[a]	balance		0,030	21,0	23,0	4,00	6,50	2,00	3,00	0,08	0,20								2,00	
	22Cr duplex	S32205	balance		0,030	22,0	23,0	4,00	6,50	3,00	3,00	0,14	0,20								2,00	
	25Cr duplex[b]	S32550	balance		0,040	24,0	27,0	4,00	6,50	2,90	3,90	0,10	0,25					1,50	2,50		1,50	
	25Cr duplex[b]	S31260	balance		0,030	24,0	26,0	5,00	7,50	2,00	3,00	0,10	0,30	0,10	0,50			0,20	0,80		1,00	
	25Cr duplex[b]	S32520	balance		0,030	24,0	26,0	5,00	8,00	3,00	5,00	0,20	0,35					0,50	3,00		1,50	
	25Cr duplex[b]	S32750	balance		0,030	24,0	26,0	6,00	8,00	3,00	5,00	0,24	0,32								1,20	
	25Cr duplex[b]	S32760	balance		0,030	24,0	26,0	6,00	8,00	3,00	4,00	0,20	0,30	0,50	1,00			0,50	1,00		1,00	
	25Cr duplex[b]	S39274	balance		0,030	24,0	26,0	6,00	8,00	2,00	3,00	0,24	0,32	1,50	2,50			0,20	0,80		1,00	

Table C.1 (*continued*)

Group	Common name	UNS	Fe		C	Cr		Ni		Mo		N		W		Nb		Cu		Mn		Other elements
			min.	max.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	
			w_{Fe} %	w_{Fe} %	w_{C} %	w_{Cr} %	w_{Cr} %	w_{Ni} %	w_{Ni} %	w_{Mo} %	w_{Mo} %	w_{N} %	w_{N} %	w_{W} %	w_{W} %	w_{Nb} %	w_{Nb} %	w_{Cu} %	w_{Cu} %	w_{Mo} %	w_{Mo} %	w %
Stainless steel		N04400		2,5	0,300			63,00	70,00									28,00	34,00		2,00	Ti 1,0 max.
	Alloy K500	N05500		2,0	0,250			63,00	70,00									balance			1,50	Al 2,30 to 3,15 Ti 0,35 to 0,85
	Alloy 20	N08020	balance		0,070	19,0	21,0	32,00	38,00	2,00	3,00							3,00	4,00		2,00	Si 1,00 max., Nb+Ta= 8C-1,00
	Alloy 800H	N08810	balance		0,100	19,0	23,0	30,00	35,00										0,75		1,50	Al 0,15 to 0,60 Ti 0,15 to 0,60
	Alloy 825	N08825	balance		0,050	19,5	23,5	38,00	46,00	2,50	3,50										1,00	Ti 0,6 to 1,2
	Alloy 904	N08904	balance		0,020	19,0	23,0	23,00	28,00	4,00	5,00										2,00	
	Type 6Mo	N08367	balance		0,030	20,0	22,0	23,50	25,50	6,00	7,00	0,18	0,25									Si 0,50 max.
	Type 6Mo	N08926	balance		0,020	19,0	21,0	24,00	26,00	6,00	7,00	0,15	0,25					0,50	1,50		2,00	
	Alloy 925	N09925	22,0		0,030	19,5	23,5	38,00	46,00	2,50	3,50										1,00	Ti 1,90 to 2,40 Si 0,50 max.
	Alloy 625	N06625		5,0	0,100	20,0	23,0	balance		8,00	10,00					3,15	4,15				0,50	Ti 0,40 max.
	Alloy 625+	N07716	balance		0,030	19,0	22,0	57,00	63,00	7,00	9,50					2,75	4,00				0,20	Ti 1,00 to 1,60
	Alloy 718	N07718	balance		0,080	17,0	21,0	50,00	55,00	2,80	3,30					4,75	5,50				0,35	Al 0,2 to 0,80, Cu 0,30 max. Ti 0,65 to 1,15
	Alloy 725	N07725			0,030	19,0	22,5	55,00	59,00	7,00	9,50					2,75	4,00				0,35	Ti 1,0 to 1,7 Si 0,20 max.
	X-750	N07750	5,0	9,0	0,080	14,0	17,0	70,00								0,70	1,20				1,00	Ti 2,25 to 2,75 Si 0,50 max.
	Alloy 28	N08028	balance		0,030	26,0	28,0	30,00	34,00	3,00	4,00							0,60				
	Alloy 2050	N06250			0,020	20,0	23,0	50,00	52,00	10,10	12,00			0,25	1,25			0,25	1,25		1,00	
	Alloy 2550	N06255			0,030	23,0	26,0	47,00	52,00	6,00	9,00										1,00	Cu 1,2 max.

Table C.1 (*continued*)

Group	**Common name**	**UNS**	**Fe**		**C**	**Cr**		**Ni**		**Mo**		**N**		**W**		**Nb**		**Cu**		**Mn**		**Other elements**
			min.	max.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	min.	max.	
			w_{Fe}	w_{Fe}	w_{C}	w_{Cr}	w_{Cr}	w_{Ni}	w_{Ni}	w_{Mo}	w_{Mo}	w_{N}	w_{N}	w_{W}	w_{W}	w_{Nb}	w_{Nb}	w_{Cu}	w_{Cu}	w_{Mo}	w_{Mo}	w
			%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%
Stainless steel	Alloy 276	N10276	4,0	7,0	0,020	14,5	16,5	balance		15,00	17,00			3,00	4,50						1,00	Co 2,5 max.
	Alloy 22	N06022	2,0	6,0	0,015	20,0	22,5	balance		12,50	14,50			2,50	3,50							Co 2,5 max.
	Alloy 2000	N60200		3,0	0,010	22,0	24,0	balance		15,00	17,00							1,30	1,90			Co 2,0 max. Mn 0,50 max.
	Alloy 59	N06059		1,5	0,010	22,0	24,0	balance		15,00	16,50											Si 0,10 max. Al 0,1 to 0,4
Copper-based alloys	CuNi 70/30	C71500	0,4	1,0	0,050			29,00	33,00									balance				Mn 1,0 max. Pb 0,02 max. Zn 0,5 max.
	CuNi 90/10	C70600	1,0	1,8	0,050			9,00	11,00									balance				Mn 1,0 max. Pb 0,02 max. Zn 0,5 max.

NOTE 1 This table is intended for reference purposes and represents a non-inclusive list; other materials can be used. Trade names are included for information only.

NOTE 2 The chemical composition of UNS numbers is given. Phosphorus and sulfur are impurity elements and are not included.

[a] UNS S31803 should be used in order to have a minimum nitrogen content of 0,14 % (mass fraction).

[b] Type 25Cr duplex should be specified to have a PREN ⩾ 40.

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