

BS EN ISO 15589-2:2014



BSI Standards Publication

Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems

Part 2: Offshore pipelines

bsi.

...making excellence a habit.
AVA Documents™
Document Sharing Hub

National foreword

This British Standard is the UK implementation of EN ISO 15589-2:2014. It is identical to ISO 15589-2:2012. It supersedes BS ISO 15589-2:2012, which is withdrawn.

The UK participation in its preparation was entrusted by Technical Committee PSE/17, Materials and equipment for petroleum, petrochemical and natural gas industries, to Subcommittee PSE/17/2, Transmission pipelines.

A list of organizations represented on this subcommittee 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.

© The British Standards Institution 2014.
Published by BSI Standards Limited 2014

ISBN 978 0 580 83141 6

ICS 75.200

Compliance with a British Standard cannot confer immunity from legal obligations.

This British Standard was published under the authority of the Standards Policy and Strategy Committee on 31 December 2012.

Amendments/corrigenda issued since publication

Date	Text affected
31 May 2014	This corrigendum renumbers BS ISO 15589-2:2012 as BS EN ISO 15589-2:2014

English Version

Petroleum, petrochemical and natural gas industries - Cathodic protection of pipeline transportation systems - Part 2: Offshore pipelines (ISO 15589-2:2012)

Industries du pétrole, de la pétrochimie et du gaz naturel - Protection cathodique des systèmes de transport par conduites - Partie 2: Conduites en mer (ISO 15589-2:2012)

Erdöl- und Erdgasindustrie - Kathodischer Schutz für Transportleitungssysteme - Teil 2: Offshore-Pipelines (ISO 15589-2:2012)

This European Standard was approved by CEN on 6 March 2014.

CEN members are bound to comply with the CEN/CENELEC Internal Regulations which stipulate the conditions for giving this European Standard the status of a national standard without any alteration. Up-to-date lists and bibliographical references concerning such national standards may be obtained on application to the CEN-CENELEC Management Centre or to any CEN member.

This European Standard exists in three official versions (English, French, German). A version in any other language made by translation under the responsibility of a CEN member into its own language and notified to the CEN-CENELEC Management Centre has the same status as the official versions.

CEN members are the national standards bodies of Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, Former Yugoslav Republic of Macedonia, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.



EUROPEAN COMMITTEE FOR STANDARDIZATION
COMITÉ EUROPÉEN DE NORMALISATION
EUROPÄISCHES KOMITEE FÜR NORMUNG

CEN-CENELEC Management Centre: Avenue Marnix 17, B-1000 Brussels

Foreword

The text of ISO 15589-2:2012 has been prepared by Technical Committee ISO/TC 67 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” of the International Organization for Standardization (ISO) and has been taken over as EN ISO 15589-2:2014 by Technical Committee CEN/TC 219 “Cathodic protection” the secretariat of which is held by BSI.

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 September 2014, and conflicting national standards shall be withdrawn at the latest by September 2014.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. CEN [and/or CENELEC] shall not be held responsible for identifying any or all such patent rights.

According to the CEN-CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, Former Yugoslav Republic of Macedonia, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom.

Endorsement notice

The text of ISO 15589-2:2012 has been approved by CEN as EN ISO 15589-2:2014 without any modification.

Contents

Page

Introduction	v
1 Scope	1
2 Normative references	1
3 Terms and definitions	2
4 Symbols and abbreviated terms	4
4.1 Symbols	4
4.2 Abbreviated terms	4
5 General	5
5.1 Competence assurance	5
5.2 Compliance	5
6 Cathodic protection system requirements	5
6.1 General	5
6.2 Selection of CP systems	6
6.3 Isolating joints	6
7 Design parameters	7
7.1 General	7
7.2 Protection potentials	8
7.3 Design life	10
7.4 Design current densities for bare steel	10
7.5 Coating breakdown factors	12
8 Galvanic anodes	15
8.1 Design of system	15
8.2 Selection of anode material	16
8.3 Electrochemical properties	17
8.4 Anode shape and utilization factor	17
8.5 Mechanical and electrical considerations	18
9 Galvanic anode manufacturing	18
9.1 Pre-production test	18
9.2 Coating	18
9.3 Anode core materials	19
9.4 Aluminium anode materials	19
9.5 Zinc anode materials	20
10 Galvanic anode quality control	20
10.1 General	20
10.2 Steel anode cores	20
10.3 Chemical analysis of anode alloy	21
10.4 Anode mass	21
10.5 Anode dimensions and straightness	21
10.6 Anode core dimensions and position	22
10.7 Anode surface irregularities	22
10.8 Cracks	22
10.9 Internal defects, destructive testing	23
10.10 Electrochemical quality control testing	24
11 Galvanic anode installation	25
12 Impressed-current CP systems	26
12.1 Current sources and control	26
12.2 Impressed-current anode materials	26
12.3 System design	26

12.4	Manufacturing and installation considerations.....	27
12.5	Mechanical and electrical considerations.....	27
13	Documentation.....	28
13.1	Design, manufacturing and installation documentation.....	28
13.2	Commissioning procedures.....	29
13.3	Operating and maintenance manual.....	29
14	Operation, monitoring and maintenance of CP systems.....	30
14.1	General.....	30
14.2	Monitoring plans.....	30
14.3	Repair.....	30
Annex A (normative) Galvanic anode CP design procedures.....		31
Annex B (normative) Attenuation of protection.....		37
Annex C (normative) Performance testing of galvanic anode materials.....		40
Annex D (normative) CP monitoring and surveys.....		42
Annex E (normative) Laboratory testing of galvanic anodes for quality control.....		49
Annex F (informative) Interference.....		51
Annex G (informative) Pipeline design for CP.....		53
Bibliography.....		59

Introduction

The technical revision of this part of ISO 15589 has been carried out in order to accommodate the needs of industry and to move this International Standard to a higher level of service within the petroleum, petrochemical and natural gas industry.

Pipeline cathodic protection is achieved by the supply of sufficient direct current to the external pipe surface, so that the steel-to-electrolyte potential is lowered on all the surface to values at which external corrosion is reduced to an insignificant rate.

Cathodic protection is normally used in combination with a suitable protective coating system to protect the external surfaces of steel pipelines from corrosion.

Users of this part of ISO 15589 should be aware that further or differing requirements may be needed for individual applications. This part of ISO 15589 is not intended to prevent alternative equipment or engineering solutions from being used for individual applications. This may be particularly applicable where there is innovative or developing technology. Where an alternative is offered, it is intended that any variations from this part of ISO 15589 be identified and documented.

This part of ISO 15589 can also be used for offshore pipelines outside the petroleum, petrochemical and natural gas industries.

This page deliberately left blank

Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems —

Part 2: Offshore pipelines

1 Scope

This part of ISO 15589 specifies requirements and gives recommendations for the pre-installation surveys, design, materials, equipment, fabrication, installation, commissioning, operation, inspection and maintenance of cathodic protection (CP) systems for offshore pipelines for the petroleum, petrochemical and natural gas industries as defined in ISO 13623.

This part of ISO 15589 is applicable to carbon steel, stainless steel and flexible pipelines in offshore service.

This part of ISO 15589 is applicable to retrofits, modifications and repairs made to existing pipeline systems.

This part of ISO 15589 is applicable to all types of seawater and seabed environments encountered in submerged conditions and on risers up to mean water level.

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 1461, *Hot dip galvanized coatings on fabricated iron and steel articles — Specifications and test methods*

ISO 8044, *Corrosion of metals and alloys — Basic terms and definitions*

ISO 8501-1, *Preparation of steel substrates before application of paints and related products — Visual assessment of surface cleanliness — Part 1: Rust grades and preparation grades of uncoated steel substrates and of steel substrates after overall removal of previous coatings*

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

ISO 13623, *Petroleum and natural gas industries — Pipeline transportation systems*

ISO 15589-1, *Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems — Part 1: On-land pipelines*

ISO 15607, *Specification and qualification of welding procedures for metallic materials — General rules*

ASTM D1141¹⁾, *Standard Practice for the Preparation of Substitute Ocean Water*

AWS D1.1/D1.1M²⁾, *Structural Welding Code — Steel*

EN 10025 (all parts)³⁾, *Hot rolled products of structural steels*

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

1) American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, USA.

2) American Welding Society, 550 NW Le Jeune Road, Miami, FL 33126, USA.

3) European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000 Brussels, Belgium.

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 8044 and the following apply.

- 3.1**
anode potential
anode-to-electrolyte potential
- 3.2**
anode sled
anodes installed on a structure and connected to the pipeline by a cable
- 3.3**
closed-circuit anode potential
anode potential while electrically linked to the pipeline to be protected
- 3.4**
coating breakdown factor
 f_c
ratio of current density required to polarize a coated steel surface as compared to a bare steel surface
- 3.5**
cold shut
horizontal surface discontinuity caused by solidification of the meniscus of the partially cast anodes as a result of interrupted flow of the casting stream
- 3.6**
driving voltage
difference between the pipeline/electrolyte potential and the anode/electrolyte potential when the cathodic protection is operating
- 3.7**
electric field gradient
change in electrical potential per unit distance through a conductive medium, arising from the flow of electric current
- 3.8**
electrochemical capacity
 ϵ
total amount of electric charge that is produced when a fixed mass (usually 1 kg) of anode material is consumed electrochemically
- NOTE Electrochemical capacity is expressed in ampere hours.
- 3.9**
final current density
estimated current density at the end of the lifetime of the pipeline
- NOTE Final current density is expressed in amperes per square metre.
- 3.10**
hydrogen-induced stress cracking
HISC
cracking due to a combination of load and hydrogen embrittlement caused by the ingress of hydrogen formed at the steel surface due to the cathodic polarization

3.11

IR drop

voltage due to any current, measured between two points of the metal of the pipe or two points of the electrolyte, such as seawater or seabed, in accordance with Ohm's law

NOTE IR drop and electric field gradient are related terms.

3.12

master reference electrode

reference electrode, calibrated with the primary calibration reference electrode, used for verification of reference electrodes that are used for field or laboratory measurements

3.13

mean current density

estimated average cathodic current density for the entire lifetime of the pipeline

NOTE Mean current density is expressed in amperes per square metre.

3.14

protection potential

structure-to-electrolyte potential for which the metal corrosion rate is considered as insignificant

3.15

pitting resistance equivalent number

PREN

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

3.16

primary calibration reference electrode

reference electrode used for calibration of master reference electrodes

3.17

remotely operated vehicle

ROV

underwater vehicle operated remotely from a surface vessel or installation

[ISO 14723]

3.18

riser

part of an offshore pipeline, including any subsea spool pieces, which extends from the seabed to the pipeline termination point on an offshore installation

[ISO 13623]

3.19

utilization factor

μ

fraction of the anodic material weight of a galvanic anode that can be consumed before the anode ceases to provide the minimum required current output

4 Symbols and abbreviated terms

4.1 Symbols

ε	electrochemical capacity
f_c	coating breakdown factor
μ	utilization factor

4.2 Abbreviated terms

CAT	cold-applied tape
CE	carbon equivalent
CP	cathodic protection
CRA	corrosion-resistant alloy
EPDM	ethylene propylene diene monomer
FBE	fusion-bonded epoxy
HISC	hydrogen-induced stress cracking
HSS	heat-shrinkable sleeve
PE	polyethylene
PP	polypropylene
PREN	pitting resistance equivalent number
PU	polyurethane
ROV	remotely operated vehicle
SCE	saturated calomel electrode
SMYS	specified minimum yield strength
SRB	sulphate reducing bacteria
3LPE	three-layer polyethylene
3LPP	three-layer polypropylene

5 General

5.1 Competence assurance

Personnel who undertake the design, supervision of installation, commissioning, supervision of operation, measurements, monitoring and supervision of maintenance of cathodic protection systems shall have the appropriate level of competence for the tasks undertaken.

NOTE 1 EN 15257 or the NACE Cathodic Protection Training and Certification Programme constitute suitable methods that can be used to assess competence of cathodic protection personnel.

NOTE 2 Competence of cathodic protection personnel to the appropriate level for tasks undertaken can be demonstrated by certification in accordance with prequalification procedures such as EN 15257, the NACE Cathodic Protection Training and Certification Programme or any other equivalent scheme.

5.2 Compliance

A quality system and an environmental management system should be applied to assist compliance with the requirements of this part of ISO 15589.

NOTE ISO/TS 29001 gives sector-specific guidance on quality management systems and ISO 14001 gives guidance on the selection and use of an environmental management system.

6 Cathodic protection system requirements

6.1 General

The CP system shall be designed to prevent external corrosion over the design life of the pipeline and to:

- provide sufficient current to the pipeline to be protected and distribute this current so that the selected criteria for CP are effectively attained on the entire surface;
- provide a design life of the anode system commensurate with the required life of the protected pipeline, or to provide for periodic rehabilitation of the anode system;
- provide adequate allowance for anticipated changes in current requirements with time;
- ensure that anodes are installed where the possibility of disturbance or damage is minimal;
- provide adequate monitoring facilities to test and evaluate the system's performance.

The CP system shall be designed with due regard to environmental conditions and neighbouring structures.

Offshore pipelines that are protected by galvanic anode systems should be electrically isolated from other pipelines and structures that are protected by impressed-current systems. Offshore pipelines shall be isolated from other unprotected or less protected structures, which could drain current from the pipeline's CP system. If isolation is not practical or stray current problems are suspected, electrical continuity should be ensured.

Care shall be taken to ensure that different CP systems of adjacent pipelines or structures are compatible and that no excessive current drains from one system into an adjacent system.

The pipeline CP design shall take into account the pipeline installation method, the types of pipeline and riser, and the burial and stabilization methods proposed. Further guidance is given in Annex G.

The CP system based on galvanic anodes shall be designed for the lifetime of the pipeline system using the calculation procedure given in Annex A.

For areas with high water velocities and areas with erosion effects (e.g. from entrained sand, silt, ice particles), the design of the CP system needs special attention and additional design criteria shall be considered.

Installation of permanent test facilities should be considered, taking into account specific parameters such as pipeline length, water depth and underwater access related to the burial conditions.

ISO 15589-1 should be used for the cathodic protection of short lengths of offshore pipelines and their branches that are directly connected to cathodically protected onshore pipelines.

6.2 Selection of CP systems

6.2.1 General

CP shall be achieved using either galvanic anodes or an impressed-current system. Galvanic anodes shall be connected to the pipe, either individually or in groups

NOTE 1 Galvanic anodes are limited in current output by the anode-to-pipe driving voltage and the electrolyte resistivity. Generally, anodes are attached directly to the pipe as bracelets. Sleds of anodes can also be placed at regular intervals along the pipeline.

NOTE 2 Some pipelines can be protected by anodes located at each end. Typically, this type of installation is used on inter-platform pipelines. Anodes for the pipeline can be attached to the platform if the pipeline is electrically connected to the platform.

Items that shall be considered in selecting the system to be used are covered in 6.2.2.

6.2.2 System selection considerations

Selection of the CP system shall be based on the following considerations:

- magnitude of the protective current required;
- resistivity of the seawater;
- availability and location of suitable power sources for impressed-current systems;
- existence of any stray currents causing significant potential fluctuations between pipeline and earth that can preclude the use of galvanic anodes;
- effects of any CP interference currents on adjacent structures that might limit the use of impressed-current CP systems;
- limitations on the space available, due to the proximity of foreign structures, and related construction and maintenance concerns;
- future development of the area and any anticipated future extensions to the pipeline system;
- cost of installation, operation and maintenance;
- reliability of the overall system;
- integrity of other pipelines and/or structures existing in the same area that could be affected by impressed-current systems unless proper measures are taken to prevent these effects.

NOTE Impressed-current systems can be preferred on short pipelines which terminate at platforms that have impressed-current systems installed or where an impressed-current system is operated from the shore. Impressed-current systems can also be preferred as a retrofit system on pipelines with galvanic anode failures, excessive anode consumption, operation beyond original design life or excessive coating deterioration. Impressed current can also be the preferred method for high-resistivity water.

6.3 Isolating joints

Isolating joints should be considered at the following locations:

- at connections to onshore pipelines or onshore receiving facilities;

- at connections to pipelines that require different protection criteria;
- between cathodically protected pipelines and non-protected facilities or less protected facilities;
- between pipeline systems (or structures) protected by impressed current and galvanic anodes.

If isolating joints are used they shall be designed and installed to ensure long-term integrity and shall be positioned to allow easy access for inspection and maintenance. Detailed design requirements are given in ISO 15589-1.

7 Design parameters

7.1 General

The design of a pipeline CP system shall be based on:

- detailed information on the pipeline to be protected, including material, length, wall thickness, outside diameter, pipe-laying procedures, route, laying conditions on the sea bottom, temperature profile (operating and shut in) along its whole length, type and thickness of corrosion-protective coating(s) for pipes and fittings, presence, type and thickness of thermal insulation, mechanical protection and/or weight coating;
- environmental conditions, including diurnal and seasonal variations, such as seawater salinity, temperature and resistivity, tides and seabed resistivity along the whole length of the pipeline;
- burial status (extent of backfilling after trenching or natural burial) and soil resistivity;
- design life of the system;
- information on existing pipelines in close proximity to or crossing the new pipeline, including location, ownership and corrosion-control practices;
- information on existing CP systems (platforms, landfalls, subsea structures, etc.) and electrical pipeline isolation;
- availability of electrical power, electrical isolating devices, electrical bonds;
- applicable local legislation;
- construction dates, start-up date (required for hot lines);
- presence of fittings, J-tubes, risers, clamps, wyes, tees and other appurtenances; and
- performance data on CP systems in the same environment.

If CP performance data for similar environments is not available (for example when moving into deeper water), data on the seawater characteristics (dissolved oxygen, salinity, pH, sea currents, and fouling) shall be obtained as these can affect cathodic polarization and calcareous deposit formation. For these situations, the required information shall be obtained from field surveys and/or corrosion test data including the following:

- protective current requirements to meet applicable criteria;
- electrical resistivity of the electrolyte, including seasonal changes if relevant;
- pipe burial depth (if buried) and identification of exposed span lengths and locations;
- water temperature at the seabed;
- oxygen concentration at the seabed;
- water flow rate at the seabed, including seasonal changes if relevant;

— seabed topography.

When reviewing operating experience, the following additional data should be considered:

- electrical continuity;
- electrical isolation;
- external coating integrity;
- deviation from specifications;
- maintenance and operating data.

Design procedures for the CP based on galvanic anode systems shall be in accordance with Annex A.

7.2 Protection potentials

7.2.1 Potential criteria

To ensure that adequate CP of a pipeline is being achieved, the measured potential shall be in accordance with Table 1.

NOTE 1 The effectiveness of CP or other external corrosion-control measures can be confirmed by direct measurement of the pipeline potential. However, visual observations of progressive coating deterioration and/or corrosion, for example, are indicators of possible inadequate protection. Physical measurements of a loss of pipe wall thickness, using divers, or using internal inspection devices such as intelligent pigs, can also indicate deficiencies in the level of corrosion protection.

Table 1 — Potential criteria

Materials	Minimum negative potential V	Maximum negative potential ^a V
Carbon steels		
Immersed in seawater	– 0,80	– 1,10 ^b
Buried in sediments	– 0,90 ^f	– 1,10 ^b
Austenitic stainless steels^g		
PREN ≥ 40 ^c	– 0,30 ^d	– 1,10
PREN < 40 ^c	– 0,50 ^d	– 1,10
Duplex stainless steels	– 0,50 ^d	e
Martensitic stainless (13 % Cr) steels	– 0,50 ^d	e

The potentials are referenced to an SCE reference electrode, which are equivalent to a silver/silver chloride reference electrode (Ag/AgCl/seawater) in 30 Ω·cm seawater.

^a These negative limits also ensure negligible impact of CP on pipeline coatings.

^b Where pipeline systems are fabricated from high-strength steel (SMYS > 550 MPa), the most negative potential that can be tolerated without causing hydrogen embrittlement shall be ascertained.

^c $PREN = \%Cr + 3,3 \% (Mo + 0,5W) + 16 \%N$.

^d For stainless steels, the minimum negative potentials apply for aerobic and anaerobic conditions.

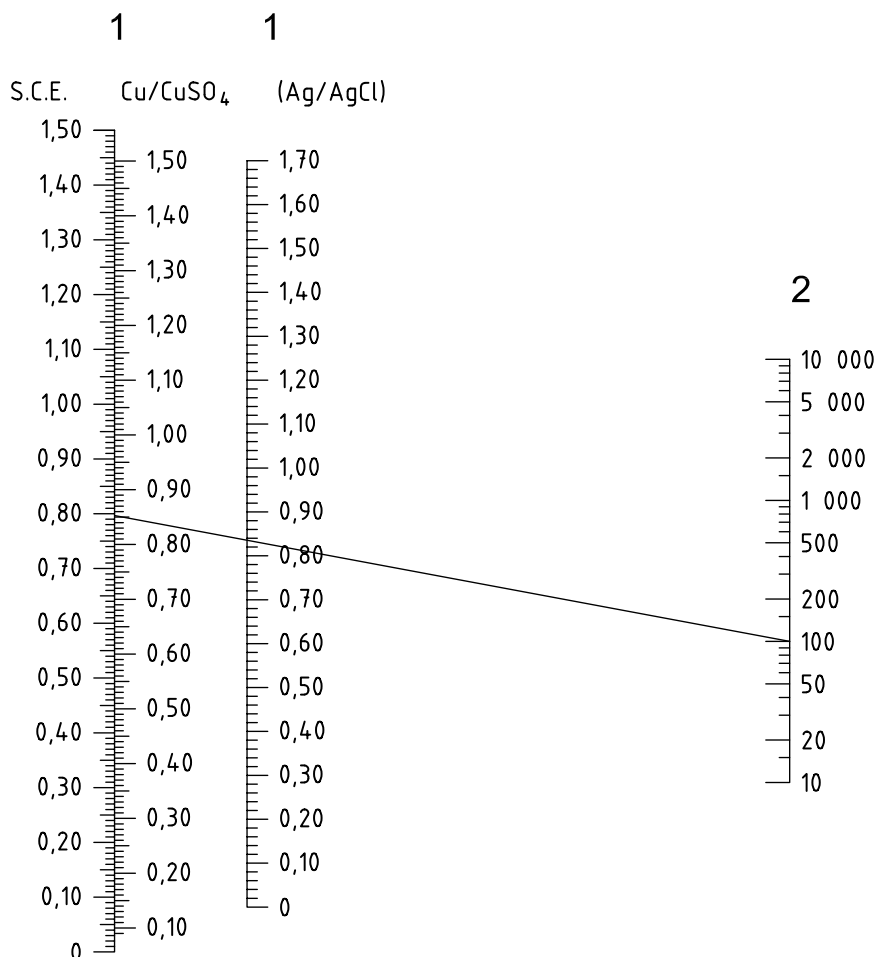
^e Depending on the strength, specific metallurgical condition and stress level encountered in service, these alloys can be susceptible to hydrogen embrittlement and cracking. If a risk of hydrogen embrittlement exists, then potentials more negative than –0,8 V should be avoided. See also 7.2.3.

^f This covers the possibility of SRB activity and/or high pipeline temperature ($T > 60^{\circ}C$).

^g If a metallurgical structure is not fully austenitic, these stainless steels can be susceptible to hydrogen-induced stress cracking (HISC) and high negative potentials should be avoided.

The potential of the Ag/AgCl/seawater reference electrode is dependent upon the concentration of chloride ions in the electrolyte, and hence the seawater resistivity. If the chloride concentration and hence the resistivity is known to differ significantly from that of ordinary seawater (typically 3,5 % and 30 $\Omega\cdot\text{cm}$ respectively), the protection potential criteria shall be adjusted in accordance with Figure 1.

NOTE 2 The term "Ag/AgCl/seawater (undersaturated) reference electrode" can be used for this electrode.



Key

- 1 potential, in volts
- 2 resistivity, in $\Omega\cdot\text{cm}$

Figure 1 — Nomogram for the correction of potential readings made with the Ag/AgCl/seawater electrode in waters of varying resistivity against the SCE and Cu/CuSO₄ reference electrodes^[17]

EXAMPLE If brackish water of 100 $\Omega\cdot\text{cm}$ resistivity exists at the pipeline potential measurement site, the least negative potential for the effective corrosion-protection electrode will be $-0,84\text{ V}$ and not $-0,80\text{ V}$ as given in Table 1, with reference to the Ag/AgCl/seawater reference electrode.

Alternative reference electrodes for specific conditions are given in D.3.2.

7.2.2 HISC evaluation for martensitic and duplex stainless steel materials

HISC is a non-ductile mode of failure caused by an interaction between stresses, the cathodic protection system and a susceptible material. A special assessment shall be carried out to ensure that the risk of HISC is minimized. All load contributions causing stress and strain shall be included.

For duplex stainless steels, DNV-RP-F112^[8] may be used to assess acceptable stresses and strains.

Fillet welds, doubler plates or aluminothermic welds should not be used directly on high-strength carbon steels (SMYS > 550 MPa), martensitic or duplex stainless steel materials. Installation of galvanic anode cables should be performed to special pipejoints consisting of internally clad carbon steel or other CRA materials which are not susceptible to HISC.

7.2.3 Thermally sprayed aluminium

If a component with thermally sprayed aluminium is cathodically protected at potentials more negative than $-1,15$ V, the thermally sprayed aluminium can suffer corrosion as a consequence of the build-up of alkali at the metal/electrolyte interface. A polarized potential more negative than $-1,15$ V should not be used unless previous test results or operating experience indicate that no significant corrosion will occur.

7.3 Design life

The design life of the pipeline CP system shall cover the period from initial installation to the end of pipeline operation as a minimum. However, the possibility of future life extension or future pipeline connections should be recognized at the design stage. Provisions should be made to accommodate possible future events and this can include revised coating breakdown criteria and/or incorporating facilities for future anode retrofits.

7.4 Design current densities for bare steel

7.4.1 General

The design current densities depend upon the seawater temperature, the oxygen content, the seawater velocity and the ability to build up protective calcareous films on bare metal surfaces.

NOTE 1 In theory, three values of current density are significant: the initial, mean and final current densities, which refer to the current density required to polarize the pipeline within a reasonable period of time (i.e. 1 to 2 months, initial), the current density necessary to maintain the polarization (mean), and the current density necessary for an eventual repolarization which may occur close to the end of the pipeline life (final), e.g. after a heavy storm. For a coated pipeline, the initial current density is never the critical constraint in the design, so it is not considered further in Annex A. Pipelines are located on the seabed and depolarization in storms has not been found to have a significant effect, so the same current density value can be used for the mean and final current densities.

If it is decided for a specific location that a higher final current density needs to be considered in the design because of storms, a value which is 20 mA/m^2 above the mean value for that temperature may be used.

For most applications in water depth of less than 500 m, the design current densities are dependent only on the seawater temperature, and the current densities for non-buried pipelines should be assessed from Figure 2.

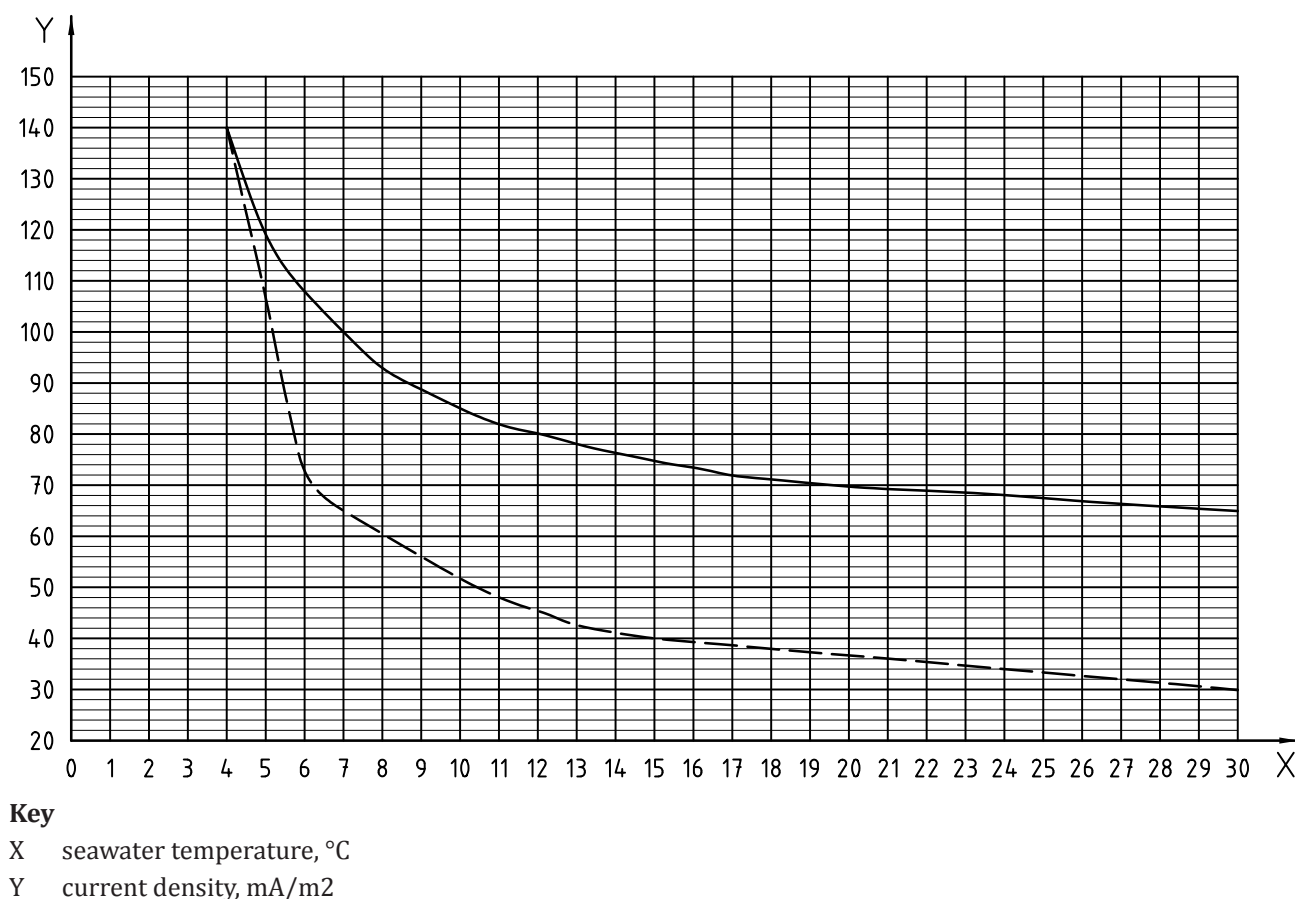


Figure 2 — Mean current density range for non-buried bare steel pipelines

In Figure 2, the lower current-density curve may be used where there are no significant changes in oxygen content from surface to seabed, no build-up of protective calcareous films, and low to moderate seabed currents (up to 2 knots).

If no other data are known, the upper curve in Figure 2 should be used.

NOTE 2 Calcareous deposits, formed on the exposed surfaces of the pipeline by the application of CP current, reduce the current density required to maintain protective potentials and also improve current distribution. Pipeline coatings also favour the formation of a dense calcareous deposit, because the initial current density is rather high when defects are formed in the coating. However, the solubility of potential film-forming calcareous deposits is dependent on temperature, and colder waters might not allow the formation of protective calcareous deposits, or could require higher initial current density to achieve polarization.

NOTE 3 The lower curve was published in Reference [19]. This curve is based on test and field data from many platform and pipeline locations world-wide, collected over a number of years. The upper curve is a conservative curve fit of the data published in References [7] and [11] and, especially for deep waters, is generally accepted by operators and represents the highest current density values reported normally for seawater saturated with oxygen. The required current density values for a given field lie somewhere between these two extremes.

At temperatures below 6 °C, the mean design current density shall be 120 mA/m², unless otherwise specified, as limited data are available for temperatures below 6 °C.

If the seawater temperature profile along the pipeline route is not known, the required current density shall be based upon the minimum seabed temperature measured, which is usually the temperature at the deepest location along the pipeline route.

If the seawater temperature profile along the pipeline route is known, the curves in Figure 2 should be used with the averaged seawater temperatures to obtain current densities for each pipeline section. If the annual average seawater temperature varies by more than 5 °C over the pipeline length, the pipeline

length should be split up into separate sections that cover intervals of no more than 5 °C each. The averaged seawater temperature should be used for each section. The design current densities discussed above are applicable for CP of bare carbon steel and stainless steel (austenitic, martensitic and duplex).

Current densities may alternatively be based on field measurements or data from facilities installed in the same general geographical location.

EXAMPLE There are specific locations where higher and lower current densities have been reported. These have been related to significant changes in oxygen content with depth, and/or significant seabed currents (see Table 2).

Table 2 — Examples of design current densities for specific locations

Location	Water depth m	Seawater temperature °C	Mean current density mA/M ²	Comment
US West Coast	> 500	10 to 12	90	moderate current flow
Cook Inlet	all depths	2	380	high seabed currents
Australia	> 500	12 to 18	90	large seasonal temperature variation
Norwegian Sea	> 1 000	-1 to 4	200	cold deep conditions
Offshore Brazil	> 300		130	temperature to be considered

7.4.2 Splash zone

For risers in the splash zone, current densities selected shall be 10 mA/m² higher than for the equivalent riser or pipeline below the splash zone (at the same temperature).

NOTE Splash zone depths vary by location; for example, in the North Sea, splash zones typically extend down to -10 m, whereas in the South China Sea, the splash zones typically extends down to -1 m.

7.4.3 Buried pipelines

For pipelines fully buried in sediments (trenched and naturally buried) or artificially covered (e.g. rock dumping), a design current density (mean and final) of 20 mA/m² should be used, irrespective of seawater temperature, oxygen content or depth.

7.4.4 Elevated temperatures

Pipelines operating with temperatures in excess of 25 °C on the outside metallic surface of the pipe require an adjustment to the design current density. The design current densities shall be increased by 1 mA/m² for each degree Celsius of the metal/environment above 25 °C up to 100 °C.

NOTE Increasing water temperature decreases oxygen solubility. Increasing temperatures also accelerate the corrosion rate.

7.4.5 Current drains

If subsea facilities are connected to the pipeline CP system, the current drain to subsea structures, wellheads, manifolds and well casing shall be included in the design. An allowance should be included in the total design current requirements to compensate for the current load imposed by the well casings below the mudline. The design current for wells should be 5 A per well.

7.5 Coating breakdown factors

The current demand of a coated pipeline increases with time as the coating deteriorates. Enough cathodic protection capacity should be provided to maintain protection as the coating deteriorates.

These coating breakdown factors shall be applied to calculate the bare metal surface areas of the coated pipe for mean conditions and at the end of the design life respectively (see Annex A). Mean and final coating breakdown factors shall be calculated as follows.

The mean coating breakdown factor, $\bar{f}_c$, is given by Equation (1):

$$\bar{f}_c = f_i + (0,5\Delta f \times t_{dl}) \quad (1)$$

The final coating breakdown factor, f_f , is given by Equation (2):

$$f_f = f_i + (\Delta f \times t_{dl}) \quad (2)$$

where

f_i is the initial coating breakdown factor at the start of pipeline operation;

Δf is the average yearly increase in the coating breakdown factor;

t_{dl} is the design life, expressed in years.

The coating breakdown factors given in Tables 3 and 4 should be considered. Coating breakdown factors for pipeline coatings not included in Tables 3 and 4 shall be fully documented.

NOTE 1 Typical parameters f_i and Δf are given in Table 3 (for pipelines without concrete weight coating) and Table 4 (for pipelines with concrete weight coating) which address combinations of the most common coating systems used for corrosion prevention or thermal insulation. The coating breakdown factors given refer to both seawater exposed pipelines and pipelines buried in the seabed.

NOTE 2 The coating breakdown factors are based on coating quality being in accordance with the various parts of ISO 21809[4] or with other commonly applied industry standards specifying an equal level of quality coatings. The coating breakdown factors include some allowance for damage to pipeline coatings during fabrication, handling, transportation, installation or operation such as third-party damage (e.g. anchors, trawl gear). However, they do not include allowance for extreme damage or for field joints intentionally left uncoated.

If extreme damage or uncoated field joints are anticipated, the affected surface area shall be estimated and included in design calculations as bare metal surface ($f_c = 1$), or increase the coating breakdown factors in Tables 3 and 4.