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Industries du pétrole et du gaz naturel — Systèmes de transport par conduites

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8.4 Coatings

8.4.1 General

All external and internal coatings shall comply with a recognized standard or specification, covering the following requirements:

- type of coating and reinforcement, where relevant;
- thickness of individual layers and total thickness;
- composition and/or base material;

— mechanical properties;

— temperature limitations;

— surface preparation requirements;

— adhesion requirements;

— requirements for materials, application and curing, including possible requirements for health, safety and environmental aspects;

— requirements for qualification testing of coating system and personnel where relevant;

— requirements for testing and inspection;

— repair procedures where relevant.

8.4.2 External coatings

8.4.2.1 Concrete weight coatings

Concrete weight coating shall comply with a specification which, in addition to the requirements of 8.4.1, covers the following requirements:

— composition of the concrete;

— required mechanical properties and test requirements;

— thickness and mass, including tolerances;

— reinforcement;

— adhesion to the pipe;

— requirements for application and curing;

— sacrificial anode installation;

— water absorption.

8.4.2.2 Coating for corrosion prevention and thermal insulation

Coating should comply with the requirements of 9.4 and 9.5.

8.4.3 Internal coatings/linings

Internal coating should in general comply with the requirements of 9.3.5 if applied to mitigate internal corrosion.

Anti-friction coatings should as a minimum comply with API RP 5L2 and have a minimum thickness of 40 µm. The coating may consist of an epoxy base and a curing agent based on epoxy aliphatic/cycloaliphatic amine or polyamide.

9 Corrosion management

9.1 General

Internal and external corrosion of pipeline systems shall be managed to prevent unacceptable risk of pipeline failure or loss of operability from corrosion within the specified design life. The corrosion management should include:

— identification and evaluation of the potential sources of corrosion;

— selection of the pipeline materials;

— identification of the necessary corrosion mitigation;

— definition of the requirements for corrosion monitoring and inspection;

— review of the findings from corrosion monitoring and inspection;

— periodic modification of the requirements of corrosion management, as dictated by experience and changes in the design conditions and environment of the pipeline.

Internal and external corrosivity evaluations shall be carried out to document that, for the selected material(s), corrosion can be controlled within the design intent over the design life of the pipeline.

The evaluations should be based on relevant operating and maintenance experience and/or the results of laboratory testing.

Any corrosion allowance should take into account the type and rate of corrosion predicted for the design life of the pipeline.

Possible internal and external corrosion of pipeline materials during transport, storage, construction, testing, preservation, commissioning and operational upset conditions shall be included in the evaluations.

9.2 Internal corrosivity evaluation

Possible loss or degradation of the pipeline materials shall be determined for all design conditions (5.1).

The possible formation of free liquid water shall be evaluated for the fluid velocities, pressures and temperatures anticipated during operations.

Components of the fluid(s) which may cause or affect internal corrosion shall be identified, and their potential for corrosion determined for the predicted ranges of concentrations, pressures and temperatures.

EXAMPLES Components which may cause or affect internal corrosion of pipelines transporting natural gases, crude oils or other produced fluids include carbon dioxide, hydrogen sulfide, elemental sulfur, mercury, oxygen, water, dissolved salts (chlorides, bicarbonates, carboxylates, etc.), solid deposits (in relation to line cleanliness), bacterial contamination, chemical additives injected during upstream activities, contamination from upstream process upsets.

The types of potential corrosion to be addressed shall include:

— general material loss and degradation;

— localized corrosion, such as pitting under deposits and mesa- or crevice-type attack;

— microbiologically induced corrosion;

— stress cracking;

— hydrogen-induced cracking or stepwise cracking;

— stress-oriented hydrogen-induced cracking;

— erosion and erosion-corrosion;

— corrosion fatigue;

— bimetallic/galvanic couples including preferential weld corrosion.

9.3 Internal corrosion mitigation

9.3.1 Methods

Methods for the mitigation of internal corrosion may include:

— a modification of design/operating conditions;

— the use of corrosion-resistant materials;

— the use of chemical additives;

— the application of internal coatings or linings;

— the use of regular mechanical cleaning;

— the elimination of bimetallic couples.

The compatibility of the selected mitigation with downstream operations should be considered.

9.3.2 Revision of design conditions

The fluid processing facilities upstream of the pipeline, and the procedures for operating the pipeline, may be reviewed to identify opportunities for the removal of corrosive components or conditions identified during the corrosivity evaluation.

9.3.3 Corrosion-resistant materials

The selection of a corrosion-resistant material shall take into account the results of the internal (9.2) and external (9.4) corrosivity evaluations.

9.3.4 Chemical additives

Factors to be considered during the selection of chemical additives should include:

— effectiveness at water-wetted areas over the full pipeline circumference and length;

— velocity variation of pipeline fluids;

— partitioning behaviour in multiphase systems;

— influence of sediments and scales;

— compatibility with other additives;

— compatibility with the pipeline component materials, in particular non-metallic materials in pipeline accessories;

— personnel safety in chemicals handling;

— environmental effects in the event of discharge;

— compatibility with operations downstream of the pipeline.

9.3.5 Internal coatings or linings

Coatings or linings may be applied to reduce internal corrosion provided that it is demonstrated that incomplete protection, at areas such as holidays and other defects, does not lead to unacceptable corrosion.

Factors to be considered during coating or lining selection should include:

— internal coating of field joints;

— application methods;

— availability of repair methods;

— operating conditions;

— long-term effects of the fluid(s) on the coating/lining;

— resistance to pressure change;

— influence of temperature gradients over the coating;

— compatibility with pigging operations.

9.3.6 Cleaning

Requirements for the periodic internal mechanical cleaning of a pipeline should be determined. Factors to be considered should include:

— the removal of accumulated solids and/or pockets of corrosive liquid to assist in the reduction of corrosion in these areas;

— enhancement of the effectiveness of chemical additives.

In choosing a mechanical cleaning device, consideration should be given to:

— the possible consequences of removing protective layers of corrosion products or chemical additives, or damage to internal coatings or linings, by mechanical cleaning;

— the possible adverse effects of contacts between pipeline materials, such as stainless steels, and the materials of mechanical cleaning devices.

9.4 External corrosion evaluation

The possibility of external corrosion occurring shall be determined on the basis of pipeline operating temperatures (see 5.1) and the external conditions along the pipeline (see 6.2).

Table 6 lists typical environments which shall be considered when evaluating the possibility of external corrosion.

Table 6 — Environments to be considered for external corrosion

Offshore pipelines	Pipelines on land
Atmosphere (marine)	Atmosphere (marine/industrial/rural)
Air/water interface (splash zone)	Sea water (tidal zone/shore approach)
Sea water	Fresh or brackish water
Seabed or buried in seabed	Marshes and swamps
Inside bundles or sleeves	River crossings
Rock dump/concrete mattresses	Dry or wet soil
Inside J-tubes/caissons	Inside tunnels, sleeves or caissons

Environmental parameters which should be considered include:

— ambient temperatures;

— resistivity, salinity and oxygen content of the environment;

— bacterial activity;

— water current;

— degree of burial;

— potential in-growth of tree roots;

— potential soil pollution by hydrocarbons and other pollutants.

The evaluation of corrosion measures should take into account the probable long-term corrosivity of the environment rather than be solely confined to the as-installed corrosivity. For a pipeline on land, due consideration should be given to any known planned changes in the use of the land traversed by the pipeline route which may alter the environmental conditions and thus soil corrosivity, e.g. irrigation of land previously arid or of low corrosivity.

The possible effect of the pH of the environment and possible sources of stray and alternating currents shall be evaluated for pipelines on land.

The types of external corrosion damage to be considered shall include:

— general metal loss and degradation;

— localized corrosion, e.g. pitting under deposit or crevice attack;

— microbiologically induced corrosion;

— stress-corrosion cracking, e.g. carbonate/bicarbonate attack.

9.5 External corrosion mitigation

9.5.1 Protection requirements

All metallic pipelines should be provided with an external coating and, for buried or submerged sections, cathodic protection. The use of corrosion allowance and a durable coating or the use of a corrosion-resistant alloy cladding should also be considered for areas with a high probability of severe corrosion.

EXAMPLE The splash zone is an area with a high probability of severe external corrosion of risers in offshore pipelines.

9.5.2 External coatings

The effectiveness in providing the required protection and the possible hazards during application and service shall be considered when selecting external coatings.

Parameters to be considered when evaluating the effectiveness of external coatings shall include:

- electrical resistivity of the coating;
- moisture permeation and its relation to temperature;
- required adhesion between the coating and the pipeline base material;
- required resistance to shear forces between the coating and additional coating, insulation or environment;
- susceptibility to cathodic disbondment;
- resistance to ageing, brittleness and cracking;
- requirements for coating repair;
- possible detrimental effects on the pipe material;
- possible thermal cycling;
- resistance to damage during handling, shipping, storage, installation and service.

External coatings of line pipe should be factory-applied, except for field joints and other special points which shall be coated on site.

Field joints should be protected with a coating system which is compatible with the line-pipe coating. The coating should meet or exceed the line-pipe coating specification and allow satisfactory application under the predicted field conditions. The protection of thermally insulated pipelines may require an external coating between the pipeline and the insulation.

Pipelines in J-tubes should be externally coated. Possible coating damage during installation inside J-tubes should be considered when selecting a coating.

9.5.3 Cathodic protection

9.5.3.1 Cathodic protection potentials

Cathodic protection potentials shall be maintained within the limits given in Table 7 throughout the design life of the pipeline.

Table 7 — Cathodic protection potentials for non-alloyed and low-alloyed pipelines

Reference electrode		$Cu/CuSO_4$	Ag/AgCl/Seawater
Water and low-resistivity soil Resistivity <100 Ω·m	Aerobic T < 40 °C	– 0,850 V	– 0,800 V
	Aerobic T > 60 °C	– 0,950 V	– 0,900 V
	Anaerobic	– 0,950 V	– 0,900 V
High-resistivity aerated sandy soil regions	Resistivity 100 Ω·m to 1000 Ω·m	– 0,750 V	– 0,700 V
	Resistivity > 1000 Ω·m	– 0,650 V	– 0,600 V

NOTE 1 Potentials in this Table and in NOTE 4 apply to line pipe materials with actual yield strengths of 605 MPa or less.

NOTE 2 The possibility for hydrogen embrittlement should be evaluated for steels with actual yield strengths above 605 MPa.

NOTE 3 For all steels the hardness of longitudinal and girth welds and their implications for hydrogen embrittlement under cathodic protection should be considered.

NOTE 4 The protection potential at the metal-medium interface should not be more negative than –1,150 V in case of $Cu/CuSO_4$ reference electrodes, and –1,100 V in case of Ag/AgCl reference electrodes. More negative values are acceptable provided it is demonstrated that hydrogen embrittlement damage cannot occur.

NOTE 5 The required protection potentials for stainless steels vary. However, the protection potentials shown above can be used. For duplex stainless steels used for pipelines, extreme care should be taken to avoid voltage overprotection which could lead to hydrogen-induced failures.

NOTE 6 If the protection levels for low-resistivity soils cannot be met, then these values may be used subject to proof of the high-resistance conditions.

NOTE 7 Alternative protection criteria may be applied provided it is demonstrated that the same level of protection against external corrosion is provided.

NOTE 8 The values used should be more negative than those shown within the constraints of the NOTES 1 to 7.

The protection potential criteria shown in Table 7 apply to the metal-medium interface. In the absence of interference currents this potential corresponds to the instantaneous "off" potential.

9.5.3.2 Design

The current density shall be appropriate for the pipeline temperature, the selected coating, the environment to which the pipeline is exposed and other external conditions which can effect current demand. Coating degradation, coating damage during construction and from third-party activities, and metal exposure over the design life should be predicted and taken into account when determining the design current densities.

9.5.3.2.1 Sacrificial anodes

The design of sacrificial anode protection systems shall be documented and include reference to:

— pipeline design life (see 5.1);

— design criteria and environmental conditions;

— applicable standards;

— requirements for electrical isolation;

— calculations of the pipeline area to be protected;

— performance of the anode material in the design temperature range;

— number and design of the anodes and their distribution;

— protection against the effects of possible a.c. and/or d.c. electrical interference.

9.5.3.2.2 Impressed current

The design of impressed-current protection systems shall strive for a uniform current distribution along the pipeline and shall define the permanent locations for the measurement of the protection potentials (see 9.5.3.3).

Design documentation shall at least include reference to:

— pipeline design life (see 5.1);

— design criteria and environmental conditions;

— requirements for electrical isolation;

— calculations of the pipeline area to be protected;

— anode ground bed design, its current capacity and resistance and the proposed cable installation and protection methods;

— measures required to mitigate the effects of possible a.c. and/or d.c. electrical interference;

— protection requirements prior to the commissioning of the impressed current system;

— applicable standards.

9.5.3.2.3 Connections

Cathodic protection anodes and cables should be joined to the pipeline by connections with a metallurgical bond.

The design of the connections should consider:

— the requirements for adequate electrical conductivity;

— the requirements for adequate mechanical strength and protection against potential damage during construction;

— the metallurgical effects of heating the line pipe during bonding.

The use of double plates should be considered when connecting anodes and cables to stainless steel pipelines. Possible interference by extraneous d.c. current sources in the vicinity of a pipeline and the possible effect of the protection of a new pipeline on existing protection systems shall be evaluated.

The shielding by thermal insulation and possible adverse effects of stray currents from other sources should be evaluated when considering cathodic protection systems for insulated pipelines.

9.5.3.3 Specific requirements for pipelines on land

Cathodic protection should normally be provided by impressed current.

NOTE 1 Sacrificial anode protection systems are normally only practical for pipelines with a high-quality coating in low-resistivity environments. The suitability of backfill material at anode locations should be reviewed.

Protected pipelines should, where practical, be electrically isolated from other structures, such as compressor stations and terminals, by suitable in-line isolation components.

Isolating joints should be provided with protective devices if damage from lightning or high-voltage earth currents is possible.

Low-resistance grounding to other buried metallic structures shall be avoided.

NOTE 2 It is recommended that the pipeline be isolated from structures, such as wall entries and restraints made of reinforced concrete, from the earthing conductors of electrically operated equipment and from bridges.

The possibility for corrosion on the unprotected sides of isolating couplings shall be considered when low-resistance electrolytes exist internally or externally.

Electrical continuity shall be provided across components, other than couplings/flanges, which would otherwise increase the longitudinal resistance of the pipeline.

The corrosion protection requirements of pipeline sections within sleeve or casing pipe shall be identified and applied.

Spark gaps shall be installed between protected pipelines and lightning protection systems.

If personnel safety is at risk or if an a.c. corrosion risk exists, unacceptably high a.c. voltages on a pipeline shall be prevented by providing suitable earthing devices between the pipeline and earthing systems without impacting on the cathodic protection.

Test points for the routine monitoring and testing of the cathodic protection should be installed at the following locations:

— crossings with d.c. traction systems;

— road, rail and river crossings and large embankments;

— sections installed in sleeve pipes or casings;

— isolating couplings;

— where pipelines run parallel to high-voltage cables;

— sheet piles;

— crossings with other major metallic structures with, or without, cathodic protection.

Additional test points, regularly spaced along the pipeline, should be considered to enable cathodic protection measurements to be taken for the entire pipeline route.

NOTE 3 The required test spacing depends on soil conditions, terrain and location.

9.5.3.4 Specific requirements for offshore pipelines

Cathodic protection should be by sacrificial anodes.

NOTE Experience has indicated that sacrificial anodes provide effective protection with minimum requirements for maintenance.

Electrical isolation is not typically provided between an offshore pipeline and its metallic support structure. However, electrical isolation may be provided between an offshore pipeline and connected metallic structures or other pipelines to allow the separate design and testing of the corrosion protection systems.

The cathodic protection of individual pipelines and structures shall be compatible if isolation is not provided.

Cathodic protection measurement points and techniques for offshore pipelines shall be selected to provide representative measurements of the cathodic protection levels.

Design of sacrificial anodes should be consistent with the pipeline construction method and the requirements associated with lay-barge tensioning equipment. Anode locations associated with pipeline crossings require special attention.

9.5.3.5 Cathodic protection system commissioning

Cathodic protection systems based on impressed current should normally be commissioned as soon as possible following pipeline installation. The requirement for temporary protection shall be determined in case of delays.

For all cathodic protection systems, the appropriate items from the list below shall be executed early in a system's life:

— visual inspection of anodes and pipeline coatings during installation;

— testing of power supplies;

— completion of an initial cathodic protection survey to include:

  1) testing for detrimental stray or interference currents,

  2) measurement of current demand,

  3) testing of isolating couplings,

  4) measurement of the cathodic protection potentials along the length of the pipeline;

— corrective measures if the specified protection is not achieved;

— provision of commissioning records.

9.6 Monitoring programmes and methods

9.6.1 Requirement for monitoring

The requirements for corrosion monitoring programmes shall be established on the basis of the predicted corrosion mechanisms and corrosion rates (see 9.2 and 9.4), the selected corrosion mitigation methods (see 9.3 and 9.5) and safety and environmental factors.

The use of internal inspection tools should be considered if monitoring of internal or external corrosion or other defects is required over the full length of the pipeline. Approximate rates or trends of corrosion degradation may be determined by analysis of results of consecutive metal loss inspections.

NOTE An inspection of the pipeline soon after commissioning should be considered to provide a baseline for the interpretation of future surveys.

9.6.2 Monitoring internal corrosion

9.6.2.1 Selection of techniques

The selection of techniques for the monitoring of internal corrosion shall consider:

— anticipated type of corrosion;

— potential for water separation, erosion, etc. (flow characteristics);

— anticipated corrosion rate (see 9.2);

— required accuracy;

— available internal and external access;

— hindrance of passage of pigs or inspection vehicles by internal obstructions.

NOTE Possible techniques include the installation of devices such as coupons, to give an indication of the corrosion in the pipeline, or periodic analyses of the fluid to monitor its corrosivity.

9.6.2.2 Location of test points for local corrosion monitoring

Test points for corrosion monitoring should be located along the pipeline or associated facilities, where representative indications of corrosion in the pipeline are most likely to be obtained.

9.6.3 Monitoring external pipeline condition

Accessible pipeline sections should be visually surveyed periodically to assess the conditions of the pipeline and, where applied, its coating. Buried or submerged pipelines shall also be inspected when exposed.

Close visual examination of the coating shall be carried out periodically at locations with a high probability of severe corrosion.

NOTE Periodic close internal protection surveys of the pipeline coating can be considered for this purpose where the area of possibly severe attack cannot readily be visually examined.

The requirements for periodic surveys of the coating of pipelines on land shall be determined taking into account the selected coating and predicted degradation, the soil type, the observed cathodic protection potentials and current demands, and known metal loss.

9.6.4 Monitoring cathodic protection

Periodic surveys shall be carried out to monitor the cathodic protection using, as a minimum, the test points defined in 9.5.3.3 and 9.5.3.4.

The frequency of these surveys should be based on:

— the type of protection;

— the uniformity of soil properties along the pipeline;

— the coating quality;

— safety and environmental concerns;

— possible interference from electrical sources.

The possible hindrance from alternating a.c. or direct current d.c. interference during the surveys and the interpretation of the results shall be considered during the selection of the survey method.

"Over the line" cathodic protection surveys can be performed to provide more detailed information concerning the corrosion protection of the pipeline. Such surveys are recommended when abnormal coating damage, severely corrosive conditions and/or stray current interference are suspected.

9.7 Evaluation of monitoring and inspection results

All findings of the monitoring and inspection activities shall be analysed to:

— review the adequacy of the corrosion management;

— identify possible improvements;

— indicate a requirement for further detailed assessment of the pipeline condition;

— indicate the need to modify the corrosion management requirements.

9.8 Corrosion management documentation

Documentation shall be prepared which describes the following in accordance with the requirements for corrosion management given above (see 9.1 to 9.6):

— the assessment of the corrosion threats and associated potentials for failure;

— the choice of materials and corrosion mitigation methods;

— the selection of inspection and corrosion monitoring techniques and inspection frequencies;

— any specific decommissioning and abandonment requirements associated with the selected corrosion management approach.