Specifying pipeline coatings –
What about appropriate design criteria?

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Abstract:

With pipeline constructions, coatings are often considered to be the weakest link with respect to external corrosion control. National and international mandatory regulations are in place for external corrosion control. Materials selection and coatings are the first line of defence against external corrosion. Because perfect coatings are not feasible, CP must be used in conjunction with coatings.

A specific type of coating may not be suitable for the often varying circumstances encountered at the entire track of a pipeline; specific environments require a specific set of requirements. Properties of a specific type of coating are tested under laboratory conditions to evaluate if they meet the requirements as written in various standards. However, in the design stage you should ask yourself: "Have all relevant properties been tested?" and "Are the properties tested for of any relevance?"

The criteria used in the design stage for selection of Coatings and Cathodic Protection systems will have serious consequences during the operational life time of the pipeline.

In the presentation several examples from literature resources and from case histories are shown. In some of these case histories, the use of improper selection criteria in the design phase has led to costly repairs during construction or during operation of the pipeline. From these examples several conclusions can be drawn, e.g.

- The material properties as e.g. given by suppliers, do not per se guarantee long-lasting corrosion prevention in specific circumstances.
- Conditions and results of laboratory testing are not per se representative for real practical situations.
- Testing in real practical situations contributes to development of appropriate selection criteria for field joint coatings.

1 Introduction

Oil and gas transport pipelines are mostly constructed of carbon steel, which mainly consists of iron. This is by far the favourite material for these kind of pipelines, because it has many advantages over other types of materials. However, carbon steel is vulnerable to several types of corrosion, caused by all kind of influences from the environment and the product being transported.

Pipeline coatings are often considered to be the weakest link with respect to external corrosion control. On the other hand, national and international legislative regulations are in place for external corrosion control, including regulations for field joints since they are an integral part of the pipeline. For example, in the USA these regulations are stated by the US Department of Transportation (US-DOT) and are published as CFR - Code of Federal Regulation:

- 49 CFR 192 – Transportation of natural and other gas by pipeline: Minimum Federal Safety Standards (1)
- 49 CFR 195 – Corrosion Enforcement Guidance (2)

In “49 CFR 192 subpart I – Requirements for corrosion control - §192 .455: External corrosion control” it is stated that (quote):

- …each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
    - It must have an external protective coating meeting the requirements of §192.461.
    - It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart…

Furthermore, several supporting documents are available, e.g. NACE SP0169-2007 (3) which is incorporated by reference in 49 CFR 195. It is stated that (quotes):

- § 4.2.1 - External corrosion control must be a primary consideration during the design of a piping system. Materials selection and coatings are the first line of defense against external corrosion. Because perfect coatings are not feasible, CP must be used in conjunction with coatings… Sometimes it is believed that CP is the first line of defense but according to that CFR this is not the case…
- §5.1.1 - The function of external coatings is to control corrosion by isolating the external surface of the underground or submerged piping from the environment, to reduce CP current requirements, and to improve current distribution…
- §5.1.2.3 - Unbonded coatings can create electrical shielding of the pipeline that could jeopardize the effectiveness of the CP system.

2 Prevention of corrosion

From the above it can be concluded that corrosion prevention during the entire lifecycle of the pipeline is the most important requirement for a field joint coating.

The most common type of iron corrosion is an electrochemical process in which a few dozens of chemical reactions have been identified (4). In these reactions two other molecules are involved: water and oxygen.

The function of the coating is to prevent corrosion. This can only be achieved by preventing water and oxygen from reaching the steel substrate. When these molecules are not present, corrosion of iron cannot happen. To achieve this the coatings should be impermeable for water and oxygen. Special attention should also be given to the application of the coating. Improper application may leave parts of the steel surface uncovered and when water and oxygen can reach the steel, e.g. through voids in the coating, corrosion will occur.

Damage to pipe coating is almost unavoidable during transportation and construction due to the often heavy loads involved, machinery and equipment used, and - sometimes - bad handling and installation practices in the field (5).

Furthermore, during operation of a pipeline other damages may occur such as shear of the coating caused by temperature fluctuations of the pipe, loss of essential properties due to ageing (like adhesion, permeability), and many more (5).

Breaks or holidays in pipe coatings may expose the pipe to possible corrosion, since after a pipe has been installed underground, the surrounding earth will be more or less moisture-bearing and it constitutes an effective electrolyte, which will allow the transportation of ions. This is where the cathodic protection systems comes into action; it acts like a back-up for coating imperfections.

Cathodic protection is a method in which the potential of a system is forced towards less corrosive values, thereby reducing or preventing the electrochemical corrosion reactions from occurring. This is often accomplished by applying current from an external electrical power source (impressed current) or sometimes by using a sacrificial anode.

Cathodic protection will not work underneath disbonded coatings; most coatings used nowadays consist of electrical insulating materials – such as polyolefins – and are not able to conduct cathodic protection currents needed. Spreading of CP-current from the coating voids underneath the disbonded coating will be insufficient to effectively protect steel against corrosion.

3 Design Criteria versus Total Cost of Ownership

When specifying criteria for a line pipe and field joint coating, one may easily refer to requirements as stated in several standards available. In general such standards list several properties per specific type of coating available on the market and such requirements are sometimes blindly adopted as “the design criteria”.

However, such behaviour might have serious consequences during the operational life time of the pipeline. For example:

- Varying circumstances encountered at the track of a pipeline may require a specific set of coating properties capable of meeting localized demands, e.g. varying soil types, varying seasonal ground water tables, exposure to influences to which they have limited resistance (cold, heat, UV-radiation, etc.)
- Properties as published in standards and coating performance as published by suppliers are tested under ideal laboratory conditions and may not reflect coating performance under specific circumstances.

The selection of coating performance criteria in the design stage will seriously influence the total cost of ownership during operational lifetime of a pipeline. It is often unpredictable when such poor coating performance will become manifest, but when it happens immediate ad-hoc measures are often necessary such as costly coating repairs and tuning or even redesign of a CP-system. Such measures obviously will raise the total cost of ownership, being a cost-driver that probably were not taken into account when the pipeline was designed. Therefore we should consider:

Have all relevant coating properties been tested for?
~ and ~
Are the coating properties tested for of any relevance?

4 Coating Application

After setting appropriate design criteria and selection of coatings meeting the requirements, the coating have to be applied during the construction stage. Application Procedure Specifications (APS) should be available of course, including guidelines for surface preparation, checks on ambient conditions, and application condition guidelines.

This requires that the workers have knowledge, skills and awareness of all factors that could influence an appropriate coating application and long-term performance of the coating system. To achieve this, education and training on skills and awareness is crucial.

With application of coatings, several checks, inspections and tests have to be conducted as often stated in Inspection and Test Protocols (ITP). Such tests have the intention to prevent occurrence of coating failures, either becoming manifest immediately or in future. This also requires knowledge of test-protocols, skills in operating test-equipment, and knowledge and awareness about interpretation of the test-results obtained. Several standards are available for tests to be conducted in the field (8, 9).

Despite all measures taken, coating failures occur frequently and are extensively described in literature (5, 6, 7). A vast amount of coating defect examples and probable causes are given in such literature e.g.:

- Occurrence of Leopard spots in liquid coatings due to too high salt residue contamination of prepared steel.
- Foaming of liquid coatings due to improper mixing ratio or improper ambient curing conditions.
- Voids between Heat Shrinkable Sleeves and parent coating on pipeline field joints due to poor application practices
- … and many more

5 Operation – Field Experiences

In some cases the performance of a selected coating turns out to be different from the expected performance as stated in the design criteria. Below are some experiences of coating failures as encountered in the field:

5.1 Material properties - Embrittlement

With the construction of a new oil transportation pipeline in an arctic tundra area, breaks were found in the outer polymeric casing of the thermal insulation during pipe construction. These failures were probably due to embrittlement of the polyethylene casing at ambient temperatures varying between -20 and -35 deg. C, combined with the often huge stresses induced by the mass of the pipeline and induced by improper handling. Such breaks could easily be detected by visual inspection while the pipe was still above ground, but detection of such breaks would be impossible once the pipe would have been buried. Effect of such breaks would be an ineffective thermal insulation, eventually leading to undesired clogging of the oil transport pipeline.

Several test methods are available for testing flexibility or field bending ability of a coating under controlled laboratory conditions (8 – 12, 15). Performing such tests under laboratory conditions or even field testing on samples would probably have led to selection of different coating materials and also would have prevented occurrence of these coating failures.

5.2 Material properties – Ageing and Weathering

In a case of an over ground pipeline crossing being in operation for several years in a desert area, severe disbondment of the polymeric line pipe coating was found. The failure was probably due to an inadequate UV-resistance of the polymeric coating, leading to deterioration and loss of essential properties of the coating. The failures could easily be detected by visual inspection of the above ground sections, because the deteriorated coating had fallen from the pipeline over a large area. The effect of such disbondment was an ineffective corrosion prevention of the steel pipeline.

In another case of a soil-to-air riser pipeline situated in a semi-arid desert area, the installed tape wrap coating had cracked and had partially disbonded from the pipe after being operational for several years. The failure was probably due to an inadequate long-term resistance of such coating to environmental factors, leading to deterioration and loss of essential properties of the coating. The underground situated defects could be detected by using DCVG (Direct Current Voltage Gradient) surveying techniques and the above ground defects were found by visual inspection. The effect of such disbondment was an ineffective corrosion prevention of all damaged parts of the steel pipeline, both above ground and buried. Furthermore, the installed Cathodic Protection system was probably only partially capable of protecting the pipeline from corrosion, because the disbonded parts of the coating will have caused shielding in cathodic protection.

In another case of a heat shrinkable sleeve application on a 3LPE-coated gas transport pipeline, situated in a desert area with seasonal salty ground water tables, corrosion was found underneath the applied heat shrinkable sleeves by accident after being in service for 5 years. This phenomenon could only be revealed by excavation of the field joint followed by removal of the field joint; DCVG surveying techniques were not capable of detection of these failures because the polymer backing of the heat shrinkable sleeve caused shielding in Cathodic Protection. The failure could have been caused by improper application, by inadequate inspection and testing during installation and/or by inadequate long-term resistance to environmental factors of the adhesive used with the heat shrinkable sleeve. The effect was an ineffective corrosion prevention of all field joints of this section of steel pipeline. Furthermore the corrosion processes found could easily have continued without being detected. Above all, the installed Cathodic Protection system was not capable to act as a backup for such coating imperfections since the backing of the heat shrinkable sleeve caused shielding.

Several test methods are available for testing of ageing and weathering effects on the properties of a coating under controlled laboratory conditions (8 – 12, 16, 25, 26).

5.3 Pipeline operation – Coating Disbondment

With a 3LPE-coated gas transport pipeline situated in a desert area with seasonal salty ground water tables and being in service for 5 years, a DCVG survey revealed serious holidays being present in the line pipe coating. After excavation of the pipeline and inspection of the coating, it seemed that the coating damages were probably induced by impact from heavy machineries used during handling or construction of the pipeline. Further inspection of the damaged area revealed that the coating could easily be lifted from the pipeline; adhesion of the PE-layer was completely lost over a length of approximately 5 meters on each side of the damage induced.

Loss of adhesion of the coating could have been caused by two different phenomenons. 1) the adhesive used in 3LPE coating systems was probably incapable to resist the environmental factors for long term. 2) the installed Cathodic Protection system may have caused Cathodic disbondment to a large extent. From the observations during inspection it was not clear which failure mode had prevailed.

Several test methods are available for testing of coating disbondment under controlled laboratory conditions (8 – 12, 13, 14, 20 – 23). Furthermore, laboratory test methods are available for evaluating the resistance of a coating to mechanical impacts (8 – 12, 13, 14, 17).

5.4 Considerations about laboratory testing

Performing tests under laboratory conditions would probably have been helpful in selection of appropriate coating materials. However such laboratory tests have some disadvantages:

- They often do not represent the varying and sometimes harsh conditions as encountered in practical situations. They are executed under standardized and ideal conditions
- Duration of accelerated ageing tests is often much shorter than the operational life cycle of the pipeline.

Could results of laboratory tests have predicted long-term performance in real practical situations? From the experiences listed above, one could easily conclude that laboratory testing is insufficient.

Furthermore evaluation of coating performance should focus on parameters indicating long term coating performance like

- Accelerated ageing in dry ambient conditions and immersed in hot water for long period of time (e.g. 100 days) at temperatures above the maximum service temperature (e.g. Tmax +20°C), followed by determination of properties supposed to be essential to a coating system like peel strength (to steel, to plant coatings, layer to layer), and tensile properties (e.g. elongation at break, modulus of elasticity).
- Long term cathodic disbondment resistance testing

6 Performance of Stopaq coating systems

Stopaq coating systems are tested according to ISO 21809-3 Amd. 1 (11). They have proved to meet or even exceed the requirements as stated in this standard including long term performance indicators, e.g.:

- Peel strength test were conducted at 23°C and at Tmax with respect to steel (St 2, St 3 and Sa 2½ and to plant coatings (PE, PP, and FBE) before and after dry thermal ageing and before and after hot water immersion test, both for 100 days at Tmax +20°C. No significant change in properties were found after the accelerated ageing tests compared to results observed with testing of non-aged samples.
- Cathodic disbondment resistance after 28 days were conducted at 23°C and at Tmax. The results were 0 mm disbondment, or actually -3 mm since the initial defect was completely filled with the coating compound by the self-healing effect of this coating system. Furthermore, no holidays were observed as required by the standard.
- Cathodic disbondment according to ASTM G42 was conducted at 65°C for 90 days with an applied potential of -3.0 Volts. The results were 0 mm disbondment, or actually -3 mm since the initial defect was completely filled with the coating compound by the self-healing effect of this coating system. Furthermore, no holidays were observed.

7 Conclusions

To formulate an appropriate set of design criteria:

- All factors shall be identified that could cause damage to the coating.
- Knowledge and awareness of varying circumstances along the entire track of the pipeline is essential.

Awareness:

- The material properties as e.g. specified by suppliers, do not per se guarantee long-lasting corrosion prevention in specific circumstances.
- Conditions and results of laboratory testing are not per se representative for practical situations.
- Focus on long-term performance coating properties.

Furthermore:

- Testing in real practical situations contributes to development of appropriate selection criteria for field joint coatings.
- Failure analysis of pipeline coating defects is an excellent tool to improve future coating performance and design criteria.
- … and last but not least, training and awareness in coating application will help preventing failures.

Literature

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