General practices for managing external corrosion on underground pipelines

## Table of content

WG_TP-72

1. Introduction

External corrosion is one of the threats to the integrity of pipeline infrastructure. The database of EGIG (European Gas Pipeline Incident Data Group) contains information about incidents that led to unintentional gas release from onshore high-pressure pipelines. According to this EGIG database, corrosion is the most frequent initial cause of incidents, after external interference. The EGIG database characterises corrosion among others on location (internal, external and unknown) and appearance (general, pitting and cracking) [1]. External corrosion and a pitting morphology have the largest contribution. Both the failure frequency as function of initial cause of the incident and leak size are displayed in **Error! Reference source not found.**figure 1. Leak sizes are categorized as follows:

- Pinhole/crack: the effective diameter of the hole is smaller than or equal to 2 cm;

- Hole: the effective diameter of the hole is larger than 2 cm and smaller than or equal to the diameter of the pipe;

- Rupture: the effective diameter of the hole is larger than the pipeline diameter.
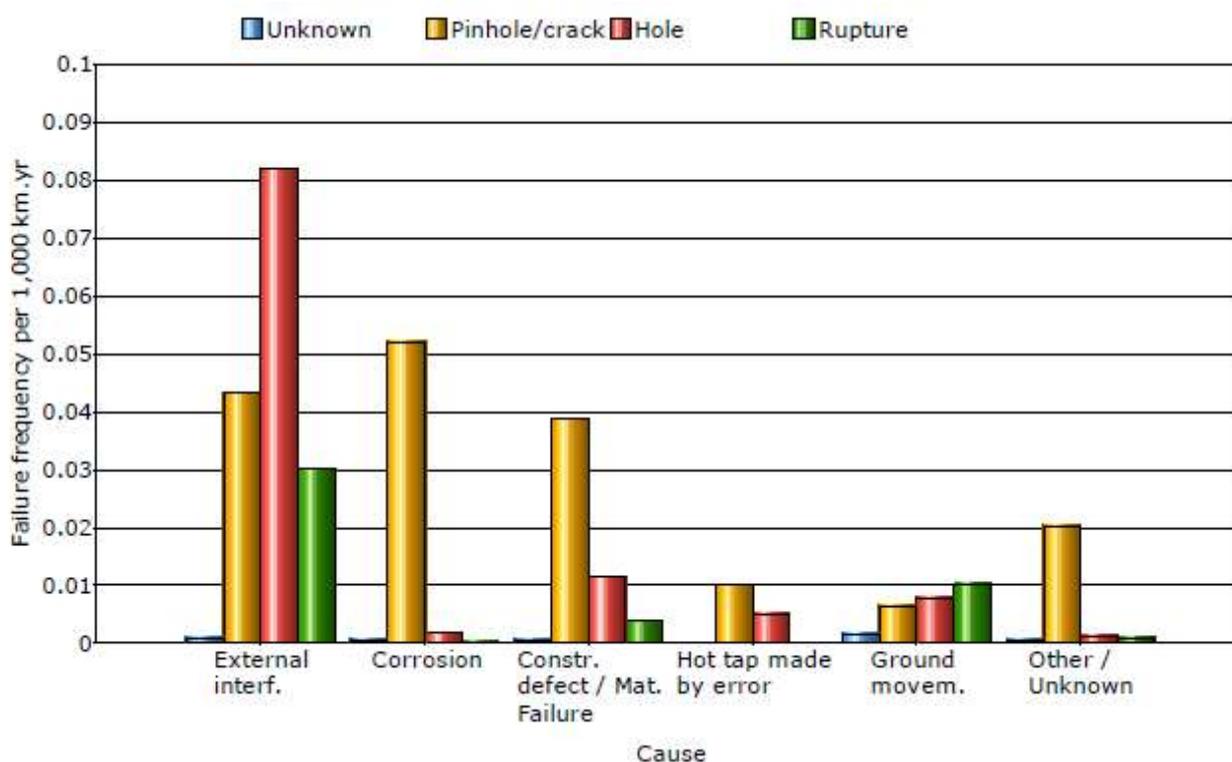
Figure 1 - Relation primary failure frequency, cause and size of leak (1970-2013)

It can be concluded that due to external corrosion, a pinhole/crack is the dominant leak size, which can be manages using normal procedures as referred to in chapter 7. If coating degenerates that severe over time the corrosion prevention by cathodic protection cannot be maintained, serious rehabilitation might be necessary and total replacement can be considered even.

Rupture is highly unlikely, but it cannot be neglected completely.

---

[1] European Gas Pipeline Incident Data Group (EGIG): "Gas Pipeline Incidents, 9th Report of the European Gas Pipeline Incident Data Group, (period 1970 – 2013)", EGIG 14.R.0403, February 2015

WG_TP-72

This paper first gives a high-level overview of national legislation in Europe on managing the integrity of pipelines in general, and on the threat of external corrosion in particular. Then it focuses on the measures taken by transmission system operators (TSO's) to prevent external corrosion leading to leakage, as well as the consequences of pipeline failure in general, including measures to manage those.

2. Applicable legislation

Any TSO must comply with legislation from national regulators. This legislation may differ among European countries, and may be influenced by cultural, historical and geographical factors, but the goal that the different legislations have in common is to prevent that construction and operation of gas transmission assets results in unacceptable risks to health, safety and the environment.

The national legislation usually is high-level and refers to technical rules and standards for specific technical requirements. The main difference between legislation, technical rules and standards is the character: it is either goal setting vs. prescriptive:

- Goal setting legislation, i.e. legislation, technical rules and standards defining the result(s) of TSO activities. Based on that, a TSO should define its own integrity approach to reach the goal(s) set. A few high-level examples are:

  o Dutch Mining Decree: "A pipeline consists of pipes that are sufficiently strong and suitably connected to one another. The pipeline is protected against corrosion and external forces";

  o EN 1594: "The pipeline shall be leak-tight and shall have the necessary resistance to safely withstand all the forces to which it is expected to be exposed during construction, testing and operation."

- Prescriptive legislation, i.e. specific measures and/or inspection methods are prescribed including an interval. Performing the prescribed measures and/or inspections, including follow-up activities where necessary, results in safe operation of gas transmission grid.

Legislation, technical rules and standards generally do not contain unambiguous and/or quantified acceptance criteria, especially not when they are goal setting. It is clear however, that no management system can exclude the occurrence of any leak completely. The small probability of a stable pinhole of hole is acceptable provided that such an incident is managed adequately.

3. Overview of measures to manage external corrosion

Based on (national) technical rules and standards, TSO's have determined the details of their own integrity approach. This includes several measures to manage the probability of external corrosion, which are typically categorized as follows:

- Prevention: applying external coating and cathodic protection (CP);

- Inspection: for example, measure pipe-to-soil potential at CP test poles, above-ground surveys, In Line Inspection (ILI, also often referred to as "pigging") and visual inspection (excavations);

WG_TP-72

- Repair and/or replacement of pipe segments, where necessary.

Each of these categories will be discussed in more detail in the following sections.

In practice, European TSO's have implemented a similar integrity approach of mitigating measures to manage external corrosion. All TSO's use all the measures described above; however, differences in legislation and cultural, historical and geographical factors, will result in a detailed difference in the implementation of these measures.

4. Prevention

Preventing external corrosion by applying external coating and CP is most effective. Coating as the primary preventive measure prevents contact between the pipe and the soil, thereby preventing corrosion to occur. Pipeline coating consists of factory applied coating and Field Joint Coating (FJC). The factory coating is applied directly after the line pipe is manufactured. The joint FJC's are applied to the sections where the line pipes are welded. Typical line coatings are bitumen coating, fusion bonded epoxy coating, polyurethane coating, three layered polyethylene (3LPE) and three-layered propylene (3LPP). Typical FJC's are: tapes, shrink sleeves, polyurethane, FBE and epoxy liquid. Main standards for coatings are ISO 21809 series.

CP prevents corrosion to occur at coating defects that may appear in the course of time. The remaining corrosion rate is less than 0.01mm/year. Impressed current systems are usually used to apply CP to the pipeline. Important standards for CP are EN 12954 *"Cathodic protection of buried or immersed metallic structures – General principles and application for pipelines", ISO 15589-1 "Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline systems — Part 1: On-land pipelines", NACE SP 0169 "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" and EN 13509 "Cathodic protection measurement techniques"*. During pipeline operation, several checks are performed to determine the effectiveness of CP. See section 7 for more details of these inspections.

For corrosion to occur both coating must be defect and / or CP must be ineffective at the location of the coating defect.

All TSO's recognise the importance of prevention and are putting much efforts in strengthening and improving that even further, see also section 9 on Research and Development.

5. Inspection

Gas transmission pipeline operators use various inspection techniques to check and improve the effectiveness of preventive measures and to detect and/or monitor external corrosion.

The following inspection techniques are used to check and improve the performance of the corrosion prevention:

- Field coating shall be inspected on electrical insulation, i.e. by spark test method

WG_TP-72

- Measure the output current of rectifiers and pipe-to-soil potential at rectifiers and CP test poles to determine CP effectiveness. An important standard is EN 13509 "*Cathodic protection measurement techniques*";

- Perform above-ground surveys to either to detect coating defects (DCVG or Pearson) or determine CP effectiveness along the pipeline (CIPS or intensive measurement). An important standard is EN 13509 "*Cathodic protection measurement techniques*";

- Execute an external corrosion direct assessment (ECDA), which is a structured process that defines locations where a pipeline is physically examined. It includes above-ground surveys and excavations to verify the condition of the pipeline with respect to external corrosion. An important standard is NACE SP 0502-2010 "*ECDA methodology*";

With these inspection techniques, prevention of external corrosion can be improved. Where necessary, CP protection of potential coating defects can be improved, thereby reducing the probability of failure due to external corrosion.

The following inspection techniques are used to detect and/or monitor loss of material in the pipeline wall or to check the fitness for service of the pipeline:

- In-line-inspection (ILI) to detect local metal loss or cracking anomalies. ILI is not meant or able to prevent corrosion of pipeline, but is aiming on detecting wall thickness reduction in case that happens. Important standards are API 1163 "*In-line Inspection Systems Qualification Standard*" and NACE SP0102 "*In-Line Inspection of Pipelines*";

- Excavations to inspect the pipeline locally. This is generally initiated by other inspection methods like ILI, above-ground surveys or ECDA; Gas leakage detection methods to detect the presence gas leaks (if any) also can be a technique to check the fitness for service of a pipeline. It detects leaks and does not help to prevent leaks. An important standard is DVGW G-465-3 "*Classification criteria for leaks in buried and not buried pipework in gas distribution systems*".

All TSO's use (almost) all of these inspection techniques, but the criteria when to use them can be different.

When legislation does not prescribe inspection techniques and/or inspection frequencies, TSO's often use a risk-based approach for prioritizing pipeline inspections. This prioritization includes probability of failure and consequence of failure. Typical parameters to determine the probability of failure are pipeline age, wall thickness, coating type, CP efficiency and/or history. See section 7, for more details on consequence of failure. There is a tendency towards increasing the use of direct inspection techniques, especially ILI for managing corrosion, both at operators and some safety supervising authorities. Several European TSO's use ILI as the preferred inspection technique, in addition to other inspections like measuring CP effectiveness and/or determining the coating condition. In some countries safety supervising authorities require that new pipelines are designed to allow for internal inspection.

Each TSO has pipelines that are not inspected with ILI. Each TSO has its own specific reasons for not pigging certain pipelines:

- Technical reasons, for example lacking launching and/or receiving facilities, obstructing parts, too small pipeline diameter or too sharp bends;

- Operation reasons, for example no back-up pipeline for gas supply or gas velocity is not within optimal range;

- Financial reasons, for example costs for modifying a pipeline to enable ILI or short pipelines that have a relative high cost per pipeline length when inspected with ILI.

It is TSO's best practice for pipelines that are not inspected with ILI to focus on the following inspection techniques:

1) Inspection of the coating condition, i.e. are there coating defects and, if so, where;

2) Inspection of the CP effectiveness, i.e. do the CP potentials along the pipeline meet the requirements.

In addition, especially in high populated areas, detection of gas leaks can be used to detect pinholes in an early stage, in case they might occur.

There are some drawbacks when not using ILI for managing external corrosion. For example, corrosion under disbanded coating cannot be detected and local CP disturbance, like DC and/or AC interference, are difficult to detect, but can be managed otherwise. So, there is the possibility that corrosion defects are not detected and properly managed. These could continue to grow and eventually may result in usually a leak in the form of a pinhole at the end. Generally, a leak would be acceptable when it does not introduce unacceptable risks for health, safety and the environment, i.e. when it is stable and gas accumulation will not occur. In addition to that, the consequences of potential leaks should be properly managed, see section 7 for more details.

Although there is an overall tendency towards the use of ILI in addition to indirect inspection strategies, ILI is not an absolute necessity to manage external corrosion for all pipelines. The probability of a leakage to occur can be kept within acceptable limits with other inspection techniques as well. Generally, legislation determines what is allowed.

For all kind of inspection results, but for excavations in particular, it is highly recommended to report not defects only, but also findings that are in accordance to a good condition, for the purpose of gathering data for analyses.

6. Repair and/or replace

Where necessary, pipeline repair and/or replacement are performed during excavations, which are typically planned based on the results (findings) of one or more inspections. During excavations, the coating is inspected first and after that, removed from the pipe. Then the pipe is inspected for corrosion defects and if present, the dimensions of the corrosion defects are determined. A defect assessment then determines whether the situation is acceptable or not. If it is, only the coating is repaired. If not, the pipe is either repaired or replaced. Examples of repair techniques are sleeves (welded, epoxy filled and composite) and composite wraps. Pipe replacement is usually carried out as a cut-out. Each TSO has its own company rules for selecting a repair technique and/or performing a pipe replace depending on dimensions, international standards and national legislation. Some relevant standards are the Pipeline Defect Assessment Manual (PDAM) and the Pipeline Repair Manual from PRCI.

WG_TP-72

In some (rather exceptional) situations the degeneration of coating might shorten the lifetime of the pipeline. If the number and size of coating defects increase that much that cathodic protection cannot be kept up to standard, serious rehabilitation or even pipeline replacement will be considered as alternative for repair.

7. Consequences of failure

The consequences of pipeline failure shall be considered during routeing of new pipelines and can be considered in for example a risk-based approach. The consequences of failure are typically determined in the following steps:

- Outflow: how much gas is released from the pipeline;

- Dispersion: where does the gas go;

- Ignition probability: where and how often will it ignite;

- Thermal radiation: how much radiation does the fire produce;

- Radiation effects: what impact does the radiation have on population and property.

These consequences are not related to external corrosion specifically, but can result from multiple threats. This includes threats like external interference, corrosion (external, internal or stress corrosion cracking), construction defects, material failure, ground movement etc.

There are several (national) standards and software packages available to determine the consequences of failure with the described approach. Typical parameters used in these calculations are population density near the pipeline, pressure, diameter and leak size.

8. Emergency planning in case of pipeline failure

Typically, the consequences of failure can be managed during design or operation. A few examples of measures for both design and operation are:

- Design: routing to maximize the distance to existing population and design according to relevant standards;

- Operation: emergency response, both by internal (for example for repair) and public emergency services working in close cooperation and closing block valves.

Again, also these measures are not in place to deal with the consequences of external corrosion specifically, but to deal with the consequences of gas leakages caused by whatever which threat, as indicated in chapter 7.

9. Research and development

TSO's and service providers continuously strive to improve CP protection and inspection techniques to detect (external corrosion) defects. TSO's keep track of and support technological developments and

innovation and are all interested in new technologies and perform pilot projects. For example, TSO's evaluate alternative inspection techniques like stress tomography and NoPig and determine whether these inspection techniques are a suitable addition to the other available inspection techniques, as described in section 5. Using the opportunities that modern technology is providing, there is a tendency to research the intelligent use of CP data and how it for example can contribute to the assessment of the condition of a pipeline.

10.   Conclusion

This paper provides an overview of legislation, technical rules, standards and measures to manage the probability and consequences of failure due to external corrosion. Legislation, technical rules and standards differ among European countries, and are influenced by cultural, historical and geographical factors; however, they focus on preventing unacceptable risks for health, safety and the environment during the construction and operation of gas transmission assets.

There are many similarities among the ways TSO's manage external corrosion, but some specificities must be considered. These specificities are mainly related to legislation, cultural, historical and geographical factors. Special emphasis is placed on proper performance of CP, being the most important line of defense if the coating as primary protection against corrosion is showing defects.

Pipeline failure caused by external corrosion usually results in pinholes or small leaks, which have low hazardous potential. It can be concluded that although there is a trend to increase the use of ILI, it is not a necessity to manage external corrosion and it is not always cost effective. In such cases, the overall operational safety can be kept acceptable with other inspection techniques as well, because other inspection techniques enable improvement of prevention of external corrosion and pipeline failure.

* * * * *