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United Kingdom Onshore Pipeline Operators' Association

UKOPA Good Practice Guide

AC Corrosion Guidelines

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The guidance in this document represents what is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered guidance and should not be considered obligatory against the judgement of the Pipeline Owner/Operator. Where new and better techniques are developed and proved, they should be adopted without waiting for modifications to the guidance in this document.

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1. EXECUTIVE SUMMARY

This Good Practice Guide (GPG) is intended to provide guidance to pipeline operators on the management of alternating current (a.c.) interference on pipelines with specific emphasis on a.c. corrosion risk. It is intended to clarify and expand upon the information originally provided in BS EN 15280 [1], which has now been withdrawn and has been replaced by BS EN ISO 18086 [2]. The electrical safety related issues on pipelines from a.c. interference is detailed in BS EN 50443 [3] and additional guidance is provided in UKOPA/TBN/005 [4].

This GPG gives information to pipeline operators on applicable standards and published literature. It also provides guidance on how to mitigate the a.c. corrosion risks on pipelines from interference caused by overhead and buried power cable systems or a.c. traction systems. The interference may occur as a result of either inductive, capacitive or resistive coupling.

The information that pipeline and power line system operators generally require to assess the levels of interference when new or existing powerline systems or power stations are installed within the vicinity of pipelines is identified in Appendices C, D and E in this GPG.

This GPG does not discuss the d.c. stray current interference risks on pipelines. Guidance on d.c. interference is given in BS EN 50162 [5], which will be replaced in the near future by ISO 21857 [6].

This GPG provides information on the management of the a.c. corrosion risk on existing pipeline systems and guidance on the a.c. interference considerations for new pipelines. A.C. corrosion can occur in certain circumstances and if the a.c. interference risk is not managed. It can result in high rates of corrosion on cathodically protected pipelines affecting pipeline integrity even if the CP levels comply with published criteria.

The GPG provides guidance on the design of a.c. interference mitigation and monitoring systems and the measures that pipeline operators should consider on existing pipelines and during the design of new pipelines or diverted pipeline systems in relation to a.c. interference.

Information on the maintenance procedures that should be followed and the nature and frequency of the tests that should be conducted on pipelines susceptible to a.c. interference to ensure that they are effectively protected from an enhanced corrosion risk due to a.c. interference is also provided.

2. INTRODUCTION

2.1 Background

This document has been prepared to provide pipeline operators with guidance on the control and management of the a.c. interference risks on buried and above ground pipelines, which can result in a.c. corrosion. The requirements in relation to evaluation of a.c. interference and corrosion risks on buried pipelines and the protection criteria to mitigate a.c. corrosion risks are defined in BS EN ISO 18086. The latter standard provides guidance on protection criteria and methods to mitigate and evaluate a.c. corrosion risk but does not provide detailed guidance on all aspects of a.c. interference. The latest international guidance on a.c. corrosion on buried pipelines is provided in National Association of Corrosion Engineers (NACE) SP 21424 [7]

The safety aspects of a.c. interference from a.c. power lines and traction systems on pipelines are detailed in BS EN 50443 and are now supplemented by the guidance given in UKOPA/TBN/005. It should be noted that UKOPA/TBN/005 is only available to UKOPA Members.

This document is intended to provide information to pipeline operators, designers and other relevant organisations on the requirements to minimize and manage the risk of a.c. corrosion on buried metallic pipelines. It is also intended to provide guidance on the operation and maintenance of pipelines that are at risk of a.c. interference and expand upon the information provided in existing standards.

2.2 Scope

The guidance in this document is applicable to all buried steel pipelines operated by UKOPA members and provides information on good practice for construction and maintenance.

It includes the risks from both 50 Hz overhead and buried power cables and a.c. traction systems.

This GPG provides information on the design of a.c. interference monitoring and mitigation systems on new and existing pipeline systems. It addresses the operational and maintenance requirements for pipelines susceptible to a.c. interference to mitigate the a.c. corrosion risk.

2.3 Application

The document is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered to be guidance and should not be considered to be obligatory against the judgement of the pipeline Owner/Operator. Where new and better techniques are developed, they should be adopted without waiting for modifications to the guidance in this document.

Within this document: **Shall:** indicates a mandatory requirement

Should: indicates good practice and is the preferred option

3. AC INTERFERENCE

3.1 General

A.C. interference on new and existing pipeline systems from crossing or parallelisms with overhead or buried power lines is a serious concern. There are two main issues associated with this phenomenon.

The electrical safety risk to pipeline personnel, sub-contractors working on a pipeline system and the general public, that arises if any contact is made to a pipeline or its above ground appurtenances, which include CP test cables, at the time that there are short term or also long-term a.c. voltages present. The electrical safety risks in relation to pipelines during both operation and construction are discussed in detail in BS EN 50443 and UKOPA/TBN/005 Electrical hazards on pipelines.

The a.c. corrosion risk on buried pipelines, which is a phenomenon that has been identified on cathodically protected pipelines throughout the world. Problems arise where there are alternating currents, above defined limits, present on a pipeline; even if the cathodic protection levels are satisfactory and meet the criteria defined in BS EN 12954 [8], there can still be ongoing corrosion. The UK experience in relation to a.c. corrosion on pipelines is summarised in Appendix E.

The a.c. corrosion criteria given in BS EN ISO 18086 have primarily been based upon laboratory studies and field measurements conducted in mainland Europe. Guidance on a.c. corrosion protection criteria is given in section 4. A certain element of caution should be exercised when interpreting data using different criteria identified in BS EN ISO 18086. Indeed, all that can be stated is that a pipeline is at risk of a.c. corrosion based upon the criteria stated, but not the rate of corrosion unless corrosion rate monitoring probes are installed. In line inspection data can provide information on the rate of defect growth and may also be used to assess rates of a.c. corrosion. There are however limitations with the ILI technique in evaluating possible a.c. corrosion features and these are discussed in section 6.15.

3.2 Coupling between Pipelines and AC Power Sources

There are three different methods of coupling between a.c. power lines and pipelines that can result in a.c. corrosion:

Low frequency induction (LFI) arises due to the inductive coupling between long structures, e.g. between pipelines and power lines where they run parallel for some distance. This is the main contributing interference source in the case of a.c. corrosion risk.

Capacitive coupling occurs due to the placing, temporarily or permanently, of pipework / pipelines in close proximity to overhead power lines. Capacitive coupling can also occur when pipelines and insulated power cables are in direct contact with each other i.e. touch each other.

Resistive coupling occurs when current discharges from a power line cable to earth. This can result in an increase in the pipeline touch potential when there is a fault associated with a particular tower and a.c. corrosion can occur during the short-term interference events. Lightning can also be a source of EPR. A lightning strike on or near a pipeline / earth grid may cause EPR, or a flashover may occur if a pipeline is too close to a power line.

3.3 A.C. Corrosion

A.C. corrosion poses a significant risk to pipeline systems and can result in accelerated corrosion on pipelines that are subjected to a.c. interference above defined levels, even if the cathodic protection criteria stated in BS EN 12954 are achieved. Appendix E of this GPG contains information on the UK's experience of a.c. corrosion and provides information on a number of case histories.

Where a.c. corrosion is occurring, then failure of a standard wall thickness pipeline system by localised corrosion could occur within a few years, if the corrosion rates are at the upper end of the possible range for a.c. corrosion , Thus, where a.c. interference does occur, it is important to ensure that it is managed and controlled within defined limits to mitigate the a.c. corrosion risk. If a corrosion risk is identified, then prompt action is required to control the a.c. corrosion risk and prevent damage to a pipeline system.

3.4 Background Information

Section 9.0 of this GPG provides details of reference publications related to the a.c. interference on buried pipelines. There are a number of published standards and informative reference documents that are available and provide good guidance and advice on the topic of a.c. interference and a.c. corrosion on pipelines. It is recommended that operators consult these documents to obtain additional guidance and information as appropriate.

Canadian Energy Pipeline Association "AC Interference Guideline Final Report - June 2014. [9], CIGRE TB 95 Guide on the influence of high voltage a.c. power systems on metallic pipelines [10] and the INGAA Foundation Report [11] in particular provide good guidance.

Appendix A provides a list of the abbreviations and three letter acronyms used in this document. Appendix B provides a list of definitions relevant to the subject under discussion in this document.

Appendix C provides the details of a typical questionnaire and information that powerline operators would require from pipeline operators, whilst Appendix D provides the typical information that pipeline operators would require of each power line operator to assess or model the a.c. interference risk.

The information the developers of new power cable systems should provide, and request of pipeline operators is detailed in Appendix E. In the UK promoters of new power systems particularly those associated with offshore energy developments or HVDC power connections have not often given sufficient consideration at an early stage in a project to the affect new power systems or modifications to existing power cable systems can have on buried utilities.

The information detailed in Appendices C and D details information that would typically be required by companies engaged to determine the short term and long term a.c. interference levels on pipelines using proprietary software packages. Typical questionnaires have been produced so that both powerline and pipeline operators can have a timely appreciation of the nature of the information required. It is essential that pipeline and power system operators agree the nature of any information required.

Appendix E provides background information on the published UK experiences in relation to a.c. corrosion.

4. AC CORROSION CRITERIA

The criteria for the mitigation of a.c. corrosion on pipelines should be based upon the guidance detailed in BS EN ISO 18086. The information on relevant criteria is summarised in this GPG.

NACE has recently published a guide on a.c. corrosion risk assessment, mitigation and monitoring namely NACE SP 21424. The latter standard provides good guidance but the acceptance criteria for a.c. corrosion do differ slightly to those proposed in BS EN ISO 18086. The guidance in this GPG is that only BS EN standards should be used to determine acceptance criteria to mitigate a.c. corrosion risk on pipelines in the UK.

The present guidance in the BS/EN standards is that the design, installation and maintenance of cathodic protection systems shall ensure that the levels of a.c. voltage on a pipeline are such that a.c. corrosion does not occur. BS EN ISO 18086 advises that since the conditions vary for each situation, a single threshold value for a.c. voltage cannot be applied. Protection against a.c. corrosion is achieved by reducing the a.c. voltage and current densities on a pipeline as follows:

- As a first step, the a.c. voltage on the pipeline should be decreased to a target value, which should be 15V rms or less. This value is measured as an average over a representative period of time (e.g. 24 hours) and as a second step, effective a.c. corrosion mitigation can be achieved by complying with the criteria defined in BS EN 12954:2001, Table 1 and:

  - Maintaining the a.c current density (rms) over a representative period of time (e.g. 24 hours) to be lower the 30 Am^{-2} on a 1 cm^2 coupon or probe.

  or

  - Maintaining the average cathodic current density over a representative period of time, (e.g. 24 hours), lower than 1 Am^{-2} on a 1 cm^2 coupon or probe if a.c. current density (rms) is more than 30 Am^{-2};

  or

  - Maintaining the ratio between a.c. current density (Ja.c.) and d.c. Current density (Jd.c.) less than 5 over a representative period of time, (e.g. 24 hours).

NOTE: Current density ratios between 3 and 5 indicate a small risk of a.c. corrosion. However, in order to reduce the corrosion risk to a minimum value, smaller ratios of current density lower than 3 would be preferable.

BS EN ISO 18086 also advises that "Further information is provided in Annex E of the standards. Effective a.c. corrosion mitigation can be also demonstrated by measurement of corrosion rate".

It is considered in this GPG that the a.c. voltage criterion of 15V rms in relation to a.c. corrosion risk given in BS EN ISO 18086 had been selected based upon historical data, as voltages in excess of the latter value have been considered in the past to provide a touch potential risk to personnel working on pipelines and the 15V rms limit has now also been applied to the mitigation of a.c corrosion risk. The permissible a.c. voltage value of 15V rms on pipelines has been included in BS EN ISO 18086 and applies to mitigation of a.c. corrosion risk. Thus, in order to mitigate against a.c corrosion the a.c. voltage on a pipeline system shall be less than 15V rms. However, the latter step is only the first step in the reduction of a.c corrosion risk.

DD CEN/TS 15280 [12] did give a maximum a.c. voltage limit on pipelines of 10V rms for soils of resistivity greater than 25 Ohm m and 4V for soil of resistivity less than 25 Ohm m. However, subsequent experience since 2005 and mainly in Europe has shown that the a.c. voltage limit alone should not be used as the basis for assessment of a.c. corrosion risk. Thus, recent standards on a.c. corrosion risk have excluded any specific a.c voltage limit on pipelines in certain soil resistivities.

The latest standards for a.c. interference on pipelines do not give an a.c. voltage limit in relation to a.c. corrosion risk, as a.c. corrosion has been known to occur at voltages less than 4V in low resistivity soils, i.e. soils of resistivity less than 25 Ohm m, whilst in soils of resistivity greater than 25 Ohm m a.c. corrosion has been found to occur at voltages less than 10V.

The UK and international experience on a.c. corrosion has shown that the a.c. voltage alone cannot be used to confirm if there is an a.c. corrosion risk, as a.c corrosion can occur at relatively low a.c. voltages. The a.c voltage levels can be used to provide an indication as to whether further investigation is required and the a.c corrosion risk needs to be evaluated. Ignoring the polarisation resistance, the a.c. current density at a coating defect with a diameter d is given by equation 1) extracted from BS EN 50162, which although the latter standard relates to d.c. current density the same formula applies to a.c current density.

$$I = \frac{8V}{\rho \pi d} \qquad (1)$$

Where
- I = Effective AC current density (Am^{-2})
- V = AC voltage on the pipeline (Volts)
- ρ = soil resistivity (Ohm m)
- d = defect diameter (m)

Equation 1) shows that the current density increases inversely with defect diameter and is related to soil resistivity. The voltage that is required on coating defects of $1cm^2$ surface area in soils of different resistivity to ensure that the a.c. current density is less than 30 Am^{-2} is an important parameter.

Soil resistivity is related to a.c. corrosion risk. The lower the soil resistivity the higher will be the a.c. corrosion risk on a pipeline, if a pipeline is affected by a.c interference such that the a.c. discharge current density values are in excess of the levels given in BS EN ISO 18086. The soil resistivity at the pipeline burial depth provides an indication of level of risk of a.c. corrosion. BS EN ISO 18086 relates the soil resistivity to a.c. corrosion risk as detailed on Table 1.

Soil Resistivity Ohm m	AC Corrosion Risk
0 to 25	Very High Risk
25 to 100	High Risk
100 to 300	Medium Risk
>300	Low Risk

Table 1 Relationship between soil resistivity and a.c. corrosion risk

It is important to confirm the soil resistivity at the pipeline burial depth along a pipeline route to identify high risk a.c. corrosion locations. This applies to both existing pipelines where an assessment of a.c. corrosion risk is required and for the design of a.c. corrosion mitigation and monitoring systems on new pipelines.

It is important to ensure that in the case of both new and existing pipeline systems that where there are particularly aggressive soil conditions e.g. salt marshes that these are identified, and suitable CP monitoring facilities are installed at those locations or as close as possible to them. CP test facilities in higher resistivity or less aggressive soil condition locations may not give a true indication of a.c. corrosion risk.

As far as the a.c. corrosion risk is concerned, the a.c. current density is the measurement that is the primary parameter to consider for assessment of risk. However, when assessing a.c. corrosion risk, using more than one acceptance criterion is recommended; as it is important to understand the limitations of the monitoring techniques employed.

The ratio between a.c. current density and d.c. current density is an important parameter. Thus, it is important to measure the d.c. current density in addition to the a.c current density to fully evaluate the a.c corrosion risk. If the d.c. current density is less than 1 Am^{-2} then NACE SP 21424 permits a higher a.c current density criterion of 100 Am^{-2}.

However, BS EN ISO 18086 simply advises that where the a.c. current density exceeds 30 Am^{-2} then the average d.c. current density over a representative period of time e.g. 24 hours should be lower than 1Am^{-2} to provide effective control of a.c. corrosion. BS EN ISO 18086 does however not give a limit on permissible a.c. current density in such a situation and that is considered to be an omission and in the absence of further guidance the limits in NACE SP21424 may be considered.

The a.c./d.c. current density ratio is only of relevance in assessing the a.c. corrosion risk if the a.c. current density exceeds the minimum criterion of 30 Am^{-2}.

BS EN ISO 18086 advises that maintaining the ratio between a.c. current density (Ja.c.) and d.c. current density (Jd.c.) less than 5 over a representative period of time, (e.g. 24 hours), would mitigate the a.c. corrosion risk. BS EN ISO 18086 further advises that current density ratios between 3 and 5 indicate a small risk of a.c. corrosion. However, in order to reduce the corrosion risk to a minimum value, smaller ratios of current density lower than 3 would be preferable.

The a.c. current density is related to the soil resistivity at a given location for a specific a.c. voltage. Table 2 gives the anticipated a.c. current density on a 1cm^2 coupon at a pipe to soil potential of 10Vrms.

Soil Resistivity Ohm m	AC Current Density Am^{-2}
1	2253
5	451
10	225
25	90
50	45
100	23

Table 2 Relationship between a.c. current density and soil resistivity a.c. voltage of 10Vrms

It can be seen from Table 2 that soil resistivity has a significant influence on the a.c. current density, hence corrosion risk. Areas of low soil resistivity e.g. salt marshes, chloride contaminated soils or peaty soils, (soil resistivities less than 25 Ohm m), are high risk locations for a.c. corrosion. The spread resistance of a coupon is related to the local soil resistivity. The spread resistance is typically quoted in terms of Ohms m^2.

The guidance in the latest standards is that at current densities in excess of 30 Am^{-2} there is an a.c. corrosion risk. The previous standards and some of the publications referenced in this GPG reference different a.c. current density criteria, but this GPG recommends that the guidance in BS EN ISO 18086 should be followed and current densities in excess of 30 Am^{-2} should be considered to indicate a risk of a.c. corrosion.

Experience has shown that generally, as the a.c current density increases above 30 Am^{-2}, then so does the corrosion rate see Figure 1 and Figure 2.

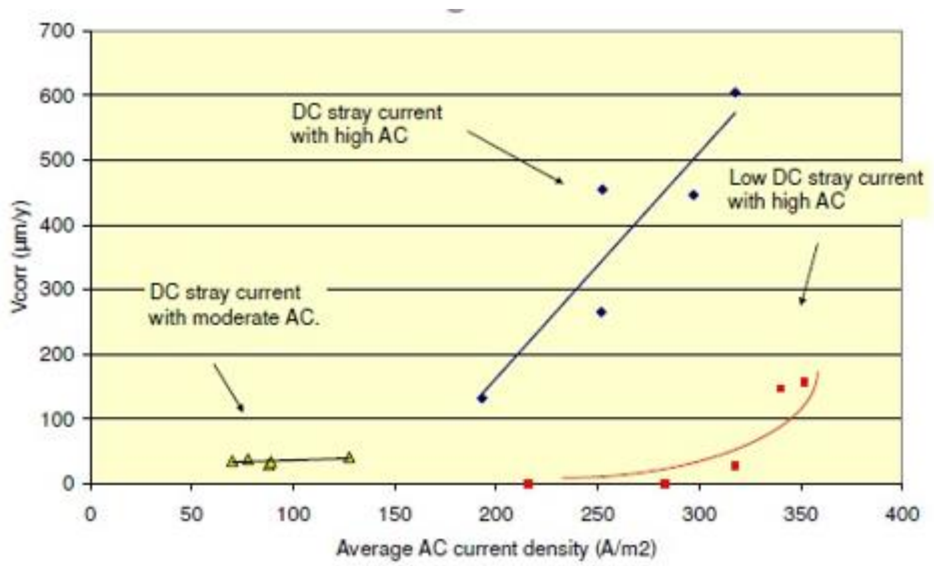


Figure 1 Relationship between Corrosion Rates and Current Density from Nielsen [13]

It can be seen from Figure 1 and Figure 2 that there is a correlation between a.c. corrosion rate and current density but it is not possible to predict the corrosion rate based upon measurement of a.c. current density alone. To ascertain the ongoing a.c. corrosion rate in a given location then corrosion rate measurement devices e.g. ER probes need to be employed.

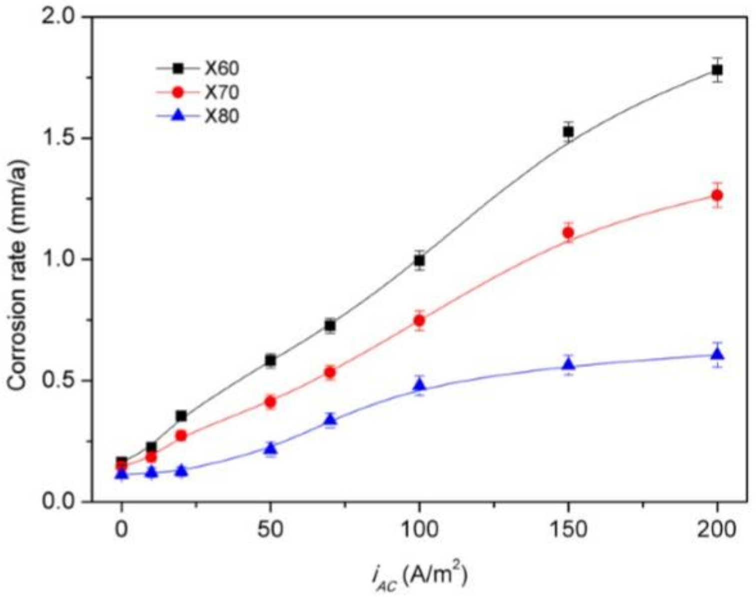


Figure 2 Relationship between AC Corrosion Rates and Current Density from Y Guo et al on different API 5LX Pipeline Steels [14]

It is essential that data logging is carried out at high risk locations for a.c. corrosion to determine a.c. pipe to soil potential and current density time dependent variations. Data logging at different times of the week should be carried out as measurements at weekends may not generally give representative values of a.c current density, since the load on power lines would be lower than during the week. Therefore, it is recommended that data logging is carried out over a 7-day period.

Data logging should also be carried out at different times of the year when the loads on the power lines are expected to vary. It should also be carried out during weekdays when industrial premises are operating and not necessarily at weekends, particularly if data logging is only performed over 24 hours. Ideally data logging should be carried out for longer periods of time e.g. 7 days with data logging at intervals of greater than one reading every 10 minutes to monitor a.c interference from overhead power lines. In the case of interference from a.c. traction systems higher monitoring frequencies are required in the region of one reading a second.

The induced a.c voltage on a pipeline is generally compared with the powerline operating data to verify the accuracy of any mathematical model and the power load data in the UK is typically only available in 15-minute increments from the power line operator. Thus, data logging at intervals between once every 1 to 5 minutes would typically be suitable for assessing a.c. corrosion risk from overhead power lines and comparing this with power line load data.

However, for interference from a.c. traction systems where interference levels can vary over relatively short periods of time then shorter intervals of between 0.1 to 5 seconds would be considered.

The measurement of a.c. current density once or twice a year at a CP test facility over a 30 second period will not give a representative indication of the a.c corrosion risk on a pipeline. It will not provide fully representative values of a.c. current density or voltage but may give an indication of whether a specific location is a high risk or not in terms of a.c. corrosion.

In the case of a.c. interference on pipelines close to power stations if the power station is not operating at the time a.c. pipe to soil potential readings are recorded then a.c voltages would be a lot lower than those when the power station is on line and would not fully reflect the a.c. corrosion risk.

For pipelines routed close to power station pylons it is important to identify if the power station was operating at the time any survey or testing was carried out.

Thus, in the case of pipelines supplying gas to power stations and routed close to powerlines then a.c. interference monitoring should ideally be performed when the power station is operating at or close to full load to ascertain the true a.c. corrosion risk.

Any data loggers used to monitor a.c. interference should also be able to provide mean values of current density and voltage and have sufficient a.c rejection capability to ensure spurious readings are not recorded.

Data logging plots should be carried out on pipelines at routine intervals during the pipeline life since there could be a considerable variation in the a.c. current density with time. Thus, taking one a.c. current density reading at a test post every 6 months may provide a good indication of the level of risk, but it may not provide fully representative values. Measurements of a.c. current densities every 6 months would identify high risk locations where further monitoring using data loggers should be conducted.

If there are borderline values of a.c. current density i.e. values close to the 30 Am^{-2} criterion recorded during 6 monthly monitoring checks, there could easily be periods of time when the a.c. current density exceeds the 30 Am^{-2} criterion. Thus, the use of data loggers to provide long term monitoring data should be considered at such locations.

In relation to mitigation of the a.c. corrosion risk, other protection criteria are also important. One of the methods of controlling a.c. corrosion risk involves maintaining the ‘ON’ pipe to soil potential within a specified range.

BS EN ISO 18086 advises that a significantly negative ‘ON’ potential can result in high cathodic current densities and in a strong change in the soil chemical composition, spread resistance and an increased reduction of oxide layers at the pipeline surface.

A.C. corrosion can be prevented when applying a sufficiently negative ‘ON’ pipe to soil potential to avoid any metal oxidation due to the presence of a.c. interference. As a consequence, the required level of the ‘ON’ potential is related to the induced a.c. voltage on the pipeline. The use of more negative ‘ON’ potentials can be indicated in the presence of d.c. stray current interference on a pipeline. However, the ‘ON’ potentials would need to be significantly negative to mitigate the a.c. corrosion risk and at such negative potentials cathodic disbondment, osmotic and non-osmotic blistering could occur on the pipeline coating, see Figure 3.

Coating disbondment, would be a problem with thin film FBE coatings at sufficiently negative potentials.

Most pipelines are not susceptible to significant levels of d.c. stray current interference and the use of a negative ‘ON’ potential to apply increased CP levels is not really practical due to the increased risk of cathodic disbondment of pipeline coatings and hydrogen embrittlement of high strength steels i.e. X80 and above.(L555).

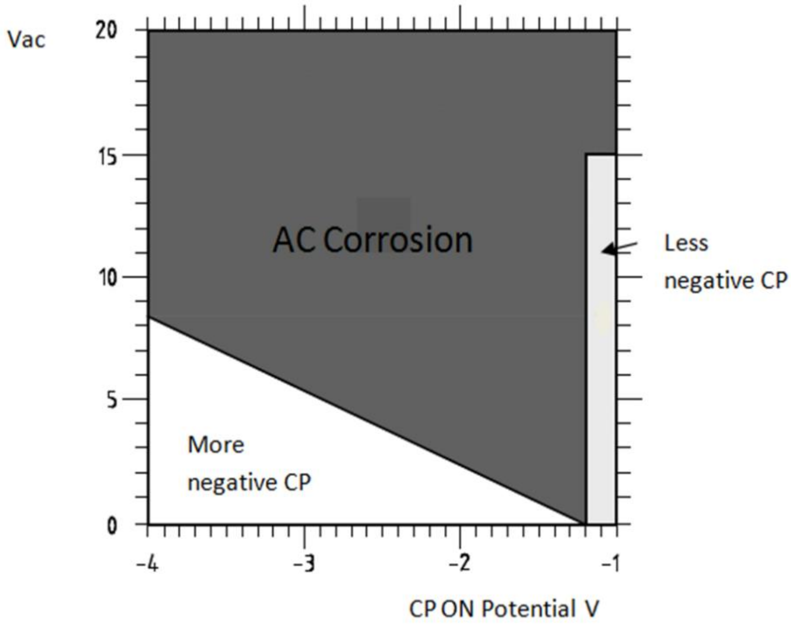


Figure 3 AC corrosion likelihood with a.c. voltage and d.c. 'ON' potential extracted from BS EN ISO 18086

Figure 3 shows that increase in the CP 'ON' potential in a more negative direction can control the a.c. interference risk as it increases the d.c. current density, but it is not really practical to use this method in the field as significantly negative pipe to soil potentials may cause problems as detailed above. Thus, for most UK pipelines, the control of the a.c. corrosion risk by control of the d.c. 'ON' potential is not recommended.

BS EN 12954 states that "Protective coatings can become damaged or polarized under the influence of cathodic protection. Coated structures should not generally be cathodically polarized beyond -1,2 V $Cu/CuSO_4$ (IR Free). Values more negative than -1.2V $Cu/CuSO_4$ (IR Free) may be used if experience or data for the particular coating system and its application demonstrate that more negative values do not cause significant detrimental coating damage or disbondment in the field".

NACE SP 21424 advises that Increasing the level of cathodic protection may be attempted in order to mitigate AC corrosion. However, the standard states that in the a.c. corrosion scenario, this will have the opposite effect, since the increase of CP current density further decreases the spread resistance at the coating defect due to the production of ions such as OH^- (alkalization).It is noted that the spread resistance may also increase rather than decrease under CP conditions as a result of the formation of high resistive films, such as magnesium-or calcium hydroxides or -oxides, on the steel surface at elevated pH conditions, if these earth alkaline cations are present in the soil. These conditions then lead to a decreased AC corrosion risk. Decrease in the spread resistance will increase the a.c. corrosion risk, whilst an increase in spread resistance will reduce it as the a.c. current density will reduce at a given a.c. pipe to soil potential.

Nielsen [13] has reported data on the relationship between a.c. corrosion rate, d.c. pipe to soil potential and a.c. voltage see

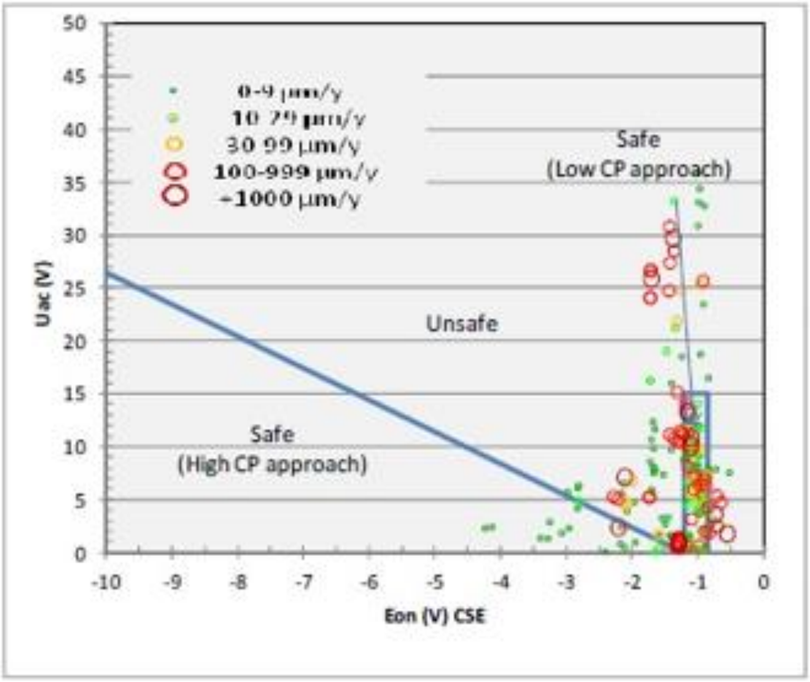


Figure 4 Relationship between Corrosion Rates and AC Voltage Current density From Nielsen [13]

A relatively positive ‘ON’ potential has only a limited effect on spread resistance. Higher negative ‘ON’ potentials increase the cathode current density and rate of hydroxyl ion formation and reduce spread resistance. The alkalinity produced at the cathode surface will cause a local reduction in resistivity and decrease the spread resistance with increase in cathode current density.

BS EN ISO 18086 advises that “ A negative ‘ON’ potential can result in a high cathodic current density and in a strong change in the soil chemical composition, spread resistance and an increased reduction of oxide layers.

A.C. corrosion can be prevented when applying a sufficiently negative ‘ON’ potential to avoid any metal oxidation due to the presence of a.c. interference. As a consequence, the required level of the ‘ON’ potential is related to the induced a.c. voltage on the pipeline.

Less negative ‘ON’ potentials will have no adverse effect on the coating adhesion and disbondment risk. They can result in insufficient cathodic protection according to the limiting potential criteria indicated in BS EN ISO 15589-1 [15] and BS EN 12954.

When choosing an a.c. corrosion prevention system based on a less negative *E*on cathodic protection level, it might be necessary to install additional CP stations along a pipeline route to limit the drain point potentials but still achieve sufficient spread of potential along the pipeline length. However, applying an ‘ON’ potential criterion that is as positive as possible, while still maintaining the ‘OFF’ potential criteria given in BS EN ISO 15589-1, will result in a decreased a.c. corrosion likelihood.

BS EN ISO 18086 advises that theoretical and practical experiences have shown that the following methods can be used to solve a.c. interference problems.

First scenario: “more negative” cathodic protection level. In this case, one of the three parameters below, in order of priority, can be applied:

The following formula should be satisfied:

1) $$\frac{U_{AC}}{E_{ON} - 1.2} < 3$$

U_{AC} = AC rms pipe to soil potential

E_{ON} = The pipe to soil ON potential

NOTE −1.2 V against Cu/$CuSO_4$ is the limiting critical potential, (see BS EN ISO 15589-1). Choosing a more positive value would create a less conservative result in the calculated ratio for given Ua.c. and Eon values.

Or

2) AC current density < 30 A/m^2;

Or

3) $\frac{J_{AC}}{J_{DC}} < 3$ if a.c. current density > 30 A/m^2;

J_{AC} = a.c. discharge current density Am^{-2}

J_{DC} = d.c. current density Am^{-2}

If the more negative 'ON' potential is applied to control the a.c. corrosion risk, it is important to ensure that there is no corrosion risk due to cathodic disbondment and no adverse effect on the pipeline steel from hydrogen evolution or embrittlement.

The use of the more negative potential criterion is not really an option for most pipeline systems because of the risk of cathodic disbondment on the pipeline coating.

The voltage criterion given in BS EN ISO 18086 namely equation 1) has been used to assess the a.c. corrosion risk on actual pipeline systems in the UK with an a.c. mitigation system installed. From the results obtained the a.c/d.c. 'ON' voltage ratio criterion of <3 given in equation 1) was not often satisfied, even on coupons where the a.c. current density was considerably below the 30 Am^{-2} criterion. This observation has shown that the ratio between a.c. voltage and d.c. 'ON' potential should not really be used to provide definitive confirmation that an a.c corrosion risk exists.

The a.c./d.c. voltage ratio given on equation 1) is not considered to be a practical method of assessing the a.c. corrosion risk and a certain element of caution should be exercised when interpreting data using the latter method.

The a.c. current density still remains the main assessment parameter in determining the a.c. corrosion risk. The a.c. to d.c. current density ratio provides confirmatory guidance but also has its limitations. It should be noted that the current density ratio only really applies in situations where the a.c. discharge current density exceeds 30 Am^{-2}.

Some organisations apply the a.c./d.c. current density ratio to assess a.c. corrosion risk for all a.c. discharge current densities, which is not correct.

A certain degree of caution should be exercised when just using current density data as a means of assessing corrosion risk. As the current density data obtained is totally reliant on intimate coupon to soil contact, which may not always be achieved. This aspect is discussed further in section 7.

Practical experience in the UK has also shown that in situations where a number of $1cm^2$ coupons are installed at the same test facility then a significant variation in a.c. current density can be recorded for different coupons. Caution should be exercised when interpreting data and where actions are planned based upon just one set of data, additional monitoring or coupons should be installed.

Other factors that affect the quality of the data obtained from coupons are the coupon construction with circular coupons being preferred as this would then enable equation 1) to be used to calculate soil resistivity from knowledge of the coupon spread resistance. However, other coupon geometries may also be utilised e.g. with ER probes.

The coupon exposed surface area must be $1cm^2$ not say $1.1\ cm^2$ or there will be a significant error in the current density data obtained. Thus, the surface area should be accurate and reproducible for all coupons. Operators should also note that if coupons are exposed to an a.c corrosion or general corrosion risk then the effective surface area may not be $1cm^2$ if corrosion has occurred over time then the actual geometric surface area could be higher. This would have an effect on the a.c. current that will be discharged and provide erroneous values for a.c discharge current density.

5. AC INTERFERENCE MITIGATION AND CODE REQUIREMENTS

5.1 Pipeline Design Code Requirements

The pipeline design code requirements in relation to a.c. interference should be identified and complied with. In the case of PD-8010-1 [16] it states “If personnel safety is at risk from a.c. voltages on the pipeline or if an a.c. corrosion risk exists, measures should be taken to mitigate the risk. These should include:

- earthing laid parallel and connected to the pipe.
- earthing mats at valves.
- connection of polarization cells or their solid-state equivalent across electrical isolating devices. to connect the pipeline to earth and to protect the electrical isolating device.
- dead front test posts to prevent third-party contact.

NOTE 1: One of the methods of monitoring the a.c. corrosion risk is by measuring the a.c. current flowing at a buried coupon installed at the location where the a.c. interference is believed to be at its greatest. These coupons normally comprise a coated metal plate with an exposed bare steel area of $1cm^2$. The coupon is normally connected to the pipe via a shunt that enables both the a.c. current flow and the d.c. current flow to be measured.

NOTE 2: Mitigation measures may be installed retrospectively, but this carries a risk of a.c. corrosion occurring before installation is complete. The installation of further mitigation measures might be necessary if the power line load increases.

PD 8010-1 advises that the need for a.c. mitigation should be identified at the design stage and this may be achieved by computer-modelling of the power line/pipeline interaction.

Pipeline design standards requirements in relation to a.c. interference should be assessed, but it should be noted that they may not always specify the latest guidance in relation to a.c. interference risks. It is considered to be beneficial to seek expert advice on a.c. interference issues and to follow the guidance in this GPG in addition to the information included in the relevant pipeline design code.

In any event, the guidance to monitor and mitigate the a.c. corrosion risk should be based upon this GPG and BS EN ISO 18086.

5.2 AC Corrosion Risk Reduction Methods

There are three different approaches to prevent a.c. corrosion; - one is to limit the a.c. current flowing through a defect, one is to control the cathodic protection level, and the other is to ensure that any coating remains defect free. These approaches are not mutually exclusive.

The creation of a defect free pipeline coating is not considered to be a viable option to control the a.c. corrosion risk as existing over the line coating defect surveys cannot locate all coating defects. In addition, a reduction in the number of coating defects could result in an increased a.c. current density on the coating defects that remain, which could also result in an enhanced a.c. corrosion risk at certain locations.

Stringent efforts are always taken during pipeline construction to identify and repair coating defects, but defects still occur, and it would not be practical to ensure a pipeline coating is defect free and remains defect free for the life of a pipeline.

The DCVG over the line survey technique is a sensitive coating defect identification technique but it does have its limitations, especially in low resistivity soils and it may not be possible to locate all coating defects on a pipeline system after pipeline installation.

For one pipeline with known corrosion features in the UK where the soil resistivity was less than 15 Ohm m a DCVG survey was conducted and none of the external a.c. corrosion defects identified on any ILI feature were identified. The limited success from the DCVG technique in low resistivity soils may be associated with the survey technique, where small percentage IR defects may not have been specifically recorded or where large DCVG indications are detected these may hide smaller ones. In low resistivity soils the IR drop at a defect location will be low and difficult to detect. In low resistivity soils, it may be advisable to a combination of coating defect surveys e.g. DCVG and ACVG to locate coating defects. It is certainly advisable to ensure all DCVG indications no matter how small are recorded.

If a defect was present in a trenchless crossing section for example it may not be possible to access the defect or carry out a repair. It is believed it is not practical or possible to achieve a defect free coating system.

Conventional over the line survey techniques do have limitations on the ability to identify pipeline coating defects where the depth of burial is greater than about 3 to 4m.

Increase in the d.c. pipe to soil potential is a method of controlling the a.c. corrosion risk but is not considered to be an option on most modern coatings namely FBE and 3-layer coatings because of the risk of cathodic disbondment.

The preferred method of control of a.c. interference risk is by reducing the a.c. discharge current density at coating defects through the installation of earthing on the pipeline. The a.c. current would then discharge to earth through the earth system installed on a pipeline and the current density through defects in the coating system should be reduced to safe limits.

However, there are other measures that may also be employed to reduce the risk of a.c. interference. On a new pipeline one measure is to use isolation joints to create shorter pipeline lengths and reduce the magnitude of a.c. interference in other sections of a pipeline. If this approach is considered, it is really only practical on new pipeline systems and needs to be considered at the route selection and pipeline design stage. Splitting the pipeline system into shorter electrically continuous sections can increase the quantity of earthing material required in other pipeline sections. It is therefore preferable to undertake mathematical modelling to ascertain if there are benefits in a given situation of installing insulation joints.

In very low resistivity areas where there is a high a.c. corrosion risk. The diverted, new or replacement pipeline sections can be installed in a high resistivity backfill when the pipeline is installed by the open cut technique. The use of a high resistivity backfill e.g. sand or limestone dust would assist in reducing the a.c. discharge current density at coating defects on the pipeline. Washed sand backfill around a pipeline section would ensure that the pipeline is exposed to a lower corrosion risk simply because the soil resistivity in intimate contact with the pipeline would be high >100 Ohm m and that would limit a.c. discharge current density at any exposed coating defects.

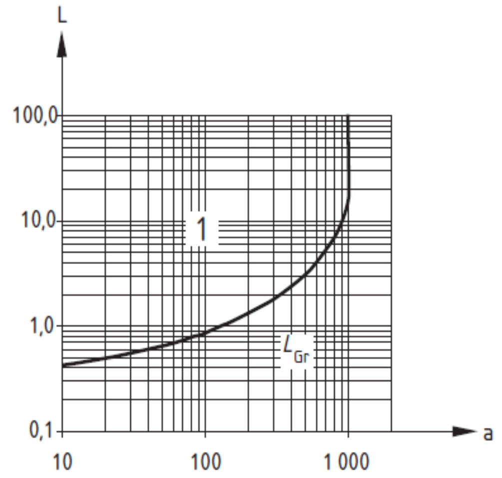
If selected backfill is used it is important to ensure that any a.c. coupons are installed in the same environment as the pipeline so that correct evaluation of a.c. monitoring data can be undertaken.

Particular attention should be paid to pipeline diversions and modifications where the new pipeline coating has a considerably higher dielectric strength than the existing pipeline e.g. connecting an FBE coated pipeline to a coal tar enamel coated pipe. In such situations, where a.c. interference is possible the a.c. current density at the higher coating quality sections can be a lot higher than on the lower coating quality sections and may be more susceptible to a.c. corrosion

The above listed measures should be considered on a case by case basis, but the use of earthing compatible with the pipeline CP system is generally the preferred option to control the a.c. corrosion risk especially on existing pipelines.

5.3 Guidance on Powerline Pipeline Influence

DD CEN/TS 15280 did give good guidance on the relationship between length of parallelism of overhead power lines and separation distance and whether verification of the level of a.c. interference is required (see Figure 5).



Key
L Length of parallelism (km)
L_{GR} Limit length
a average distance between the pipeline and the electricity line calculated on the total length of the parallelism (m)
1 Verification is necessary

Figure 5 Limit Length LGR and distance a from pipeline when laid parallel to a 50 Hz 3 phase HV power line for calculation from DD CEN/TS 15280-2006

The curve in DD CEN/TS 15280 was removed from the updated dated standard BS EN 15280 as there are so many other variables that need to be considered when determining risk of a.c. interference e.g. power line operating currents, distance between phases, operating voltages, coating conductance and soil resistivity. Thus, whilst Figure 5 does give an indication as to the distances and extents of parallelism that should be considered in the evaluation of a.c, interference risk.

Figure 5 should not however be used to provide definitive guidance such that an assessment is not required if the pipeline and power line separation and parallelism fall within the limit L_{GR} on the curve in Figure 5.

INGAA has produced a report detailing the relationship between various factors on the a.c. interference risk e.g. pipeline power line separation, power line current and crossing angle on the level of a.c. interference for a 345kV power circuit. This information is summarised on Tables 3 to 6.

Separation Distance (m)	Severity of HVAC Risk Ranking
D < 30	High
30< D> 150	Medium
150< D>300	Low
300< D> 750	Very low

Table 3 Separation distance between pipeline and power line

Powerline Current (Amps)	Severity of HVAC Risk Ranking
1000	Very High
500< I> 1000	High
250< I> 500	Medium-High
100< I> 250	Medium
I<100	Low

Table 4 Relationship between power line current and AC risk ranking

Parallelism Length L (m)	Severity of HVAC Risk Ranking
>1500	High
300< L> 1500	Medium
L<300	Low

Table 5 Separation distance between pipeline and power line

Crossing Angle Θ	Severity of HVAC Risk Ranking
Θ< 30	High
60< Θ> 30	Medium
Θ>60	Low

Table 6 Relationship between power line pipeline crossing angle and risk ranking

It is considered that the tables should give good indicative guidance to assess high and low risk a.c. situations.

CIGRE TB 95 also gives guidance on the relationship between zone of influence and power line pipeline separation.

The zone of influence *d* has to be considered when: -

$$d = 200\sqrt{\rho}$$

Where:

d = distance from pipeline below which a.c interference has to be considered (m)

ρ = soil resistivity (Ohm m),

Thus, for 100 Ohm m soil, d should be less than 2000m.

BS EN 50443 gives slightly different guidance than CIGRE TB 95 see Table 7.

Type of AC Power System	Areas	Soil Resistivity ρ (Ohm m)	Interference Distance m	
			Normal Operation	Fault Condition
Overhead	Rural	>3,000 ≤3,000	ρ/3 1000	P 3,000
Overhead	Urban	>3,000 ≤3,000	≥300	ρ/10 ≥300
Buried	All	all	50	50

Table 7 Guidance on interference distance from BS EN 50443

5.4 AC Corrosion Monitoring

To monitor the a.c. corrosion risk it is important to determine the a.c. discharge current density on a pipeline. This can only be carried out via the use of a coupon with an exposed surface area of 1cm^2. The coupons should be specifically designed for use on cathodically protected pipelines.

When a.c. coupons are installed and used for monitoring purposes to determine the risk from a.c. corrosion, then any d.c. coupon also connected to the pipeline should be disconnected when current density readings are taken. Temporary ‘T’ handle coupons can be used to provide an initial assessment of risk, if there are no permanent coupons installed, (see Figure 6). These have exposed steel tips with 1cm^2 surface area that are driven into the ground as far as practical.

The ‘T’ handle type coupons are useful for initial investigations, but the data obtained should be considered as indicative. Surface soil resistivity values will be different to those at the pipeline depth and if the surface resistivity is high that will mean that the a.c. current density may be lower than at the pipeline depth.

The length of the ‘T’ handle coupon should be selected so that it will not damage buried cables or other utilities at the probe installation location and the probe length is generally limited to 0.5m.

There are a number of different suppliers of a.c. coupons i.e. coupons that have an exposed steel surface area of 1cm^2 and the coupons should ideally have a factory connected cable rather than use cables connected to coupons in the field. It is imperative that the cable to coupon connections are effectively insulated and the coated steel surface area is minimised so that this does not result current discharge from the coupon connection or any coating leading to erroneous readings. The coupons are used specifically to assess the risk of a.c. and d.c. interference on buried pipelines.

The coupon cable conductor size should be a minimum of 10mm^2 and the cable colour should comply with the pipeline operator requirements to indicate function as an a.c. coupon. In the UK, 10cm^2 d.c. polarisation coupon cables would typically be coloured blue and 1cm^2 a.c. coupons cable typically coloured white.

It is important to ensure a clear distinction between a.c. and d.c. coupons connected into any CP test post. This can be achieved by the use of proprietary cable markers. D.C coupons when installed alongside a.c. coupons should always be disconnected when a current reading is taken through an a.c. coupon.

Figure 6 T Handle type temporary 1 cm^2 surface area a.c coupon

The preferred coupons to employ are those that are circular and have a limited exposed coated steel surface area. This is because a.c. current can also flow through the coating and provide a source of error. A typical a.c. coupon is shown on Figure 7. It is essential that the coupon surface area is accurate as even a small change in coupon diameter can result in significant errors in recorded current density.

On installation coupons need to be installed so that the exposed steel surface area is pointing away from the pipeline. They should be carefully compacted in graded local soil and the coupon spread resistance checked to confirm it is of the expected value, which is typically less than 1 Ohm m^2 before the coupon and any other monitoring equipment is completely backfilled. Similar checks to confirm probe spread resistance before backfilling should be made with ER probes. Once backfilled it will not be easy to replace any as installed probe.

On pipelines that are susceptible to an a.c. interference risk, the a.c coupon dimensions and geometric surface area can change as a result of corrosion and this can lead to erroneous a.c. current density data. Operators should be aware of the latter risk when analysing data on coupons particular where it is known that a.c. corrosion may be occurring, and coupons have been installed for some time.

Decisions are frequently made in relation to installation of expensive a.c. mitigation systems based upon the current data from coupons. It is important therefore that operators are aware that errors can occur in data measurement depending upon the coupon construction and installation.

Some older coupon designs included coupons that were strapped to pipelines but the cable to coupon connection was made on site rather than under factory-controlled conditions. The later design it is considered was not ideal and can lead to errors and is not recommended for new pipelines.

When coupons are installed, they should always be installed in local soil at the pipeline burial depth and in intimate contact with the local soil. Only local soil should surround a coupon and the coupon should be installed with the steel face pointing away from the pipeline at a distance from the pipeline of approximately 100mm. BS EN ISO 18086 advises "The *coupon or probe should have and maintain effective electrical contact with the surrounding soil – unless lack of contact is part of the purpose of monitoring. During the installation process, the soil around the coupon or probe should be compacted to prevent settlement and voids forming around the coupon or probe. These voids could result in loss of full contact between the coupon or probe surface and the surrounding soil*"

The current flow through a coupon can be measured through a shunt in series with a coupon or with suitable test equipment capable of measuring true rms with sufficient a.c. rejection capability. In low resistivity soils the typical shunt resistance of 10 Ohms can be a significant percentage of the coupon spread resistance. Thus, if the coupon spread resistance is 1000 ohms then a 1% error in measurement of current density will be achieved if the shunt resistance is 10 Ohms. However, if the coupon spread resistance is 100 Ohms then the use of a10 Ohm shunt or 200mV 20mA will cause a 10% error in current measurement. Guidance on measurement techniques for CP applications is given in BS EN 13509 [17]

Figure 7 Typical a.c. coupon

5.5 Competency and Certification

It is recommended that any a.c interference monitoring, and mitigation systems designs should be carried out by personnel having the levels of competency and certification as defined in BS EN ISO 15257 [18].

Any a.c monitoring and mitigation system designs should be carried out by a Level 4 Senior Cathodic Protection Engineer as defined in BS EN ISO 15257.

The pipeline operator should however confirm that personnel employed in design and monitoring process on pipelines susceptible to a.c. corrosion, even if BS EN ISO 15257 certified have the required levels of experience and competency in assessment of a.c interference risks on pipelines.

In relation to the modelling of the a.c. interference on pipelines, only companies with demonstrable experience in the use of proprietary software should be used to conduct the a.c. interference modelling studies. The agency employed for mathematical modelling studies should be certified in the use of the software by the software provider for short and long-term interference studies. Only software packages with a proven track record in modelling a.c. interference on pipeline systems should be used for mathematical modelling studies.

Personnel undertaking routine monitoring of a.c. interference on pipelines should also have the necessary levels of competency, certification and understanding.

It is advisable for pipeline operators to provide training to operatives to ensure that they are fully conversant with the nature of the monitoring required on pipelines affected by a.c. interference and understand the relevant safety risks.

Certification of personnel to BS EN ISO 15257 would not provide the required level of awareness in relation to the electrical safety risks associated with work on pipelines and operators should provide relevant training to ensure personnel are aware of safety risks and safe working practices. It is important that risk assessments and method statements are produced for a.c. interference monitoring and personnel undertaking the work comply with the risk assessments and method statements.

Guidance on the electrical safety considerations for routine monitoring on pipelines susceptible to a.c. interference is given in UKOPA/TBN/005.

6. INDUCED A.C. VOLTAGE LEVELS AND ASSESSMENT OF RISK

6.1 Introduction

Calculations of induced voltage for different situations can be undertaken based upon the guidance given in the documents referenced in this GPG. This GPG does not provide calculation examples but provides references for calculation methodology for both long term and short term a.c. interference. However, ISO 21857 and AS/NZS 4853 [19].do provide examples of calculation methods and should be used for reference.

It is recommended that companies which specialise in assessment of a.c. interference from cable systems, who employ suitability qualified electrical engineers undertake the modelling work. Only proprietary finite element modelling software with a proven track record for use in modelling induced a.c. interference levels should be used for any studies.

6.2 Induced Voltage Levels Buried Cables on Pipelines

The a.c. interference levels on buried pipelines from buried cables should be assessed based upon the guidance given in CIGRE TB 95. It should be noted that the interference levels on pipelines from buried cables are generally lower than for overhead power lines.

The existing a.c. voltages present on a pipeline should also be taken into consideration when assessing risk of interference from new cable systems since, whilst the existing a.c. voltages may be within limits to ensure no a.c. corrosion risk prior to installation of any cable system, even a small induced voltage from a new buried cable system could add to the voltages already present on a pipeline. The addition of voltages is not a simple numerical addition and would need to be treated as vector values.

Thus, base line and post energisation data logging should be performed to confirm that any a.c. interference risk on pipelines routed in parallel with buried high voltage power lines is within manageable limits. Additional test posts and monitoring facilities may be required to confirm the a.c. interference levels if new power cable systems are installed close to an existing pipeline.

6.3 Induced Voltages Overhead Cable Systems

The long-term a.c. interference risk on buried pipelines from overhead power lines can be calculated based upon the guidance on calculation methods given in CIGRE TB 95 and GIGRE TB 290 [20] AS/NZS 4853 also provide examples of typical calculations.

There is proprietary software that can be used to model the long term induced a.c. interference on pipelines. The models can take time to run and should be conducted by specialists experienced in producing a model and using the software.

Information is required from the pipeline system operator and also the power line operator. A typical questionnaire that would be submitted to a pipeline operator is given in Appendix C and a typical questionnaire that would be submitted to the power line operator is given in Appendix D.

Most high voltage power lines have overhead earth wires in their construction. These overhead earth wires have a shielding effect on the pipeline, which will reduce the LFI in the pipeline.

6.4 Rail Traction System Interference

If pipelines cross a.c. traction systems at right angles and do not run in parallel with the traction system for any appreciable distance, then the levels of interference from a 25kV traction system should be low.

However, a.c. monitoring coupons should be installed at CP test facilities located on each side of any a.c. traction system so that the a.c. interference levels can be monitored.

Where a pipeline crosses a rail line, the crossing should be at right angles and the pipeline should be routed so that it is equidistant between rail line pylons. This will limit the ground potential rise on the pipeline during fault conditions on the traction system. Typical fault currents from on rail traction systems vary with distance from the substation with typical values in the region to 1 to 12 kA.

The pipeline should ideally be installed in a high resistivity bentonite-based alkaline grout at the crossing point of resistivity greater than 100 Ohm m. Bentonite alone if used for sleeved crossings or to provide selected backfill for open cut crossings would be have a low resistivity at 1 Ohm m and provide a low soil resistivity and thus be a high risk environment in terms of a.c. corrosion risk.

The risk in relation to pipelines in close proximity to railway systems occurs where the pipeline is routed in a parallel with the traction circuits and can collect traction return currents by resistive coupling and also inductive/capacitive coupling from the live traction cables.

BS EN 50443 advises that capacitive coupling from a railway system has to be considered in case of proximity lower than:

10 m in case of 15 kV, 16,7 Hz systems;

a) 50 m in case of 25 kV, 50 Hz systems.

BS EN 50443 advises that conductive or resistive coupling from an a.c. electric traction systems shall be considered in case of crossing or proximity lower than 5m from the nearest rail or masts or metallic components connected to the rails. However, practical guidance would be that separation distance of at least 20m should be considered between rail line and traction line earths.

Modelling of the effects of a.c. interference from a.c. traction systems should be undertaken by specialists experienced in this field. The nature of the rail electrification system would need to be established and information provided on the location of any a.c. booster stations, train frequencies on the rail line and operating currents for different scenarios. Soil resistivity data at substation locations and at 1 to 2 km intervals along route of any affected section should be obtained. The relative positions of feed and return conductors including earth wires should be confirmed, the number of substations and distance the traction circuit runs parallel with pipeline and separation distance between the two.

The maximum and normal loads on the rail system and fault current at substations and on pylons close to pipeline should be confirmed and the rail operator should provide information on the number of track circuits and power lines operating at 25 kV and their physical location. The location and type of feeder cables from substations, Location of traction return current paths and proportion of return current anticipated for each path, including rails and return screen conductor should be advised together with anticipated fault clearance times. The earth resistance target for any trackside equipment should also be confirmed.

The overhead aerial earth wire also has a shielding effect in reducing the levels of interference. No pipeline a.c. corrosion mitigation system earth should be installed underneath a rail line since during fault conditions the ground potential rise on the earth may affect rail signalling systems.

All apparatus, cabling and earth systems associated with a pipeline system installed under railway lines must be approved by the rail authority. A HAZOP and HAZCON should be carried out between the pipeline operator and railway operator for new construction activities in the vicinity of rail crossings to ensure safe operation of the pipeline and railway.

6.5 Requirements to Assess Risk

Operators should carry out an assessment of the risk of a.c interference on all metallic pipeline systems that they are responsible for. If a.c. interference is then identified as a risk, appropriate measures should be implemented to monitor and mitigate the risk.

It should be stated that not all pipelines may be susceptible to a.c. interference and corrosion. The assessment process should be documented. Pipeline operators should assess the a.c. corrosion risk and the electrical safety risk to personnel. It should be stated that not all pipelines or sections of a pipeline may be susceptible to a.c. interference. The measures to monitor and mitigate the a.c. corrosion risk should include the guidance given in this GPG and BS EN ISO 18086 plus the requirements of any specific pipeline operators codes and standards. The requirements to assess the electrical safety risk to personnel on pipelines should be based upon BS EN 50443 and UKOPA/TBN/005. Pipeline systems should be evaluated on a case by case basis.

Any assessment should be prioritised with pipelines considered to have the highest level of risk being assessed first. Details on the factors to consider in relation to existing pipelines in terms of assessment of risk are given in section 7 of this GPG.

It should be noted that the level of risk to pipeline systems should be reviewed on a periodic basis as situations may change. Thus, the process of assessment should be ongoing over the life of a pipeline system as new power lines or electrical substations may be installed in the vicinity of pipelines or the loads on existing power lines increased. If such a situation occurs, then the level of induced voltage on a pipeline may change. Power line operators can increase the load on overhead power lines without notifying pipeline operators or considering the effect increased power line loads may have on buried metallic utilities.

If pipeline diversions are required, the risk of increased levels of a.c. interference on the existing pipeline as a result of any change in the pipeline route should also be considered. Measurement of the a.c. voltage on a pipeline alone will not give a true assessment of the level of a.c. corrosion risk and on susceptible pipelines methods to monitor the a.c. current density also needs to be employed

Measurement of the a.c. voltage on a pipeline alone will not give a true assessment of the level of a.c. corrosion risk and on susceptible pipelines methods to monitor the a.c and d.c. current density through the use of $1cm^2$ exposed surface area coupons also need to be employed. This will mean the installation of a.c. coupons at the pipe burial depth in appropriate test facilities. Temporary coupons may be used to provide indicative data on a.c. discharge current density.

The a.c. interference risk on all existing pipelines should be assessed in accordance with the pipeline design code requirements. All overhead power lines or a.c. substations within 1000m of a pipeline system operating at voltages of 66 kV or above should be considered.

6.6 Mathematical modelling

Where there is parallelism between pipelines and overhead or buried pipelines mathematical modelling using specialist, proprietary software can be used to determine the long term a.c. interference levels on pipelines. The long-term induced voltages can be used to calculate the induced a.c. voltage on a pipeline at a given location can be used to ascertain the likely risk of a.c corrosion. Furthermore, if there is information on the resistivity of the soil along a pipeline route then the likely a.c. current density at given locations can also be calculated.

It is recommended that companies which specialize in assessment of a.c. interference from cable systems and employ suitability qualified electrical engineers undertake the mathematical modelling work. Only proprietary software with a proven track record for use in modelling induced a.c. interference levels should be used for mathematical modelling studies on pipelines using finite element modelling.

Caution should be exercised as the mathematical models created to determine the levels of long-term interference may not be fully accurate as a number of assumptions are made when creating the model.

Experience has shown that whilst mathematical models can be useful, they may not always produce an a.c interference mitigation system design that will be fully effective and changes to the mitigation arrangement on a pipeline may be required in the future following commissioning of any a.c. mitigation system and subsequent monitoring data. Operators should validate mathematical models by undertaking appropriate a.c. monitoring on a pipeline system following installation of an a.c. mitigation system or operation of any new power cable system. On existing pipelines recorded data of a.c voltage and current density can be used to validate any model and confirm the model accuracy. To undertake system validation exercises precise information on the loads on the individual power line circuits at the time any data logging is performed would need to be established.

Mathematical modelling requires accurate information on the pipeline and power line route, details of the power system including rated and maximum loads, power cable pylon construction and details of the screen wire

The information would be required by companies engaged to determine the short term and long term a.c. interference levels on pipelines using proprietary software packages is given in Appendices C and D.

The company undertaking the modelling work should advise details of the information that will be required off power line operators to conduct the modelling studies e.g. fault current at substations and pylons, fault duration, shield wire construction, information of supply feeds to substations, power cable height above ground, power cable construction, pylon construction, whether there are any cable transpositions, operating voltage and circuit loading.

It should be noted that that on overhead power line systems where there are two circuits if one circuit is out for maintenance and only one circuit is operating the levels of induced voltage on a pipeline will be a lot higher than when both circuits are operating. In two circuit operation the electromagnetic fields can be cancelled out and reduce the interference levels on pipelines.

If the circuit loads are not balanced, then the levels of long-term interference on pipelines will be higher than when circuit loading is balanced e.g. one circuit operating at 100% of maximum load and the other at say 60% of maximum load is an unbalanced loads scenario. Pipeline operators will need to agree the circuit load scenario to be used for any model with the modelling company. The resultant model should be based upon the likely power cable load scenarios.

The likely scenarios are normal load, maximum load and rated load. The extent of circuit imbalance should also be established. The normal load is the load the power cable system will typically operate at, the maximum load is the maximum load it can operate at with the power system that is presently configured and the rated load is the load that the power cable system can theoretically carry if additional power sources e.g. larger substations are connected to it.

6.7 A.C. Corrosion Risk Assessment

Consideration should be given to pipelines routed in close proximity to a.c. traction or power systems. It is recommended that operators prioritise the level of risk as some pipeline systems will have a higher risk of a.c. corrosion than others.

The consequences of failure on a pipeline system also need to be considered, when assessing risk. Table 8 gives information on the factors that need to be considered when assessing risk.

Parameter	Limitations	Parameter	Assessment
Soil resistivity	Is data available?	Values less than 25-ohm m are high risk, 25 to 100 medium risk	Lower resistivity higher a.c. corrosion risk values if less than 10-ohm m significant risk
Power lines separation	Need to look at pipelines with 2000m of power lines	Separation distance needs to be measured	Closer HV lines to pipelines higher risk
Length of Parallelism	Anything about 300m in length should be considered	Check from accurate route drawings	Longer parallel lengths higher risk
Date of Construction	Older pipelines	Coating impedance	Older pipelines a.c. corrosion rates lower but newer pipelines coating systems more susceptible to a.c. corrosion
Pipe Wall thickness	Corrosion rate will result in perforation of thin wall pipe first	Pipelines with higher design safety factor sections lower risk of failure	Lower wall thickness of pipe greater risk if a.c. is identified as risk
AC pipe voltage	As low as possible less than 15V	Voltage should be monitored with data logger over at least 24 hours	Higher the voltage possibly higher risk
AC current density	<30 Am^{-2}	Current density monitored with logger over at least 24 hours	Higher current density higher risk generally
Pigable Lines	Some, a.c. defect sizes are generally small and not often excavated after pig runs	When analysing pig run data look for growth in the smaller defects that would be typical of a.c. defects	Pigging data provides good indication of any ongoing a.c. corrosion risk and defect growth
Non pigable lines	On non pigable lines excavation of coating defects may be required	Coating defect surveys required to identify coating defects then check soil resistivity and a.c. current density at defect to identify if there is a risk of corrosion	Non pigable pipelines need detailed assessment. May need to take measures to reduce pressure to conduct examination if metal loss suspected

Table 8 Parameters to consider when assessing a.c. interference risk on existing pipelines

The assessment should include in relation to a.c. corrosion;

a) The long term induced a.c. interference risk

b) Determining locations where soil resistivity is less than 25 Ohm m

c) Pipeline coating system and coating defect survey data

d) The location of power lines in relation to the pipeline route and their operating voltages

e) Measurement of a.c. voltage on pipeline system

f) Measurement of a.c. and d.c. current density through 1 cm2 coupons

g) Review intelligent pig run data

h) A.C. corrosion risk and future monitoring of the pipeline system to confirm corrosion risk status

Experience has shown that areas of low soil resistivity along a pipeline route are high risk locations for a.c. corrosion at relatively low a.c potentials. At such locations CP monitoring test facilities with a.c. coupons should be installed.

If a pipeline is routed parallel to HV power cable systems at operating voltages of 132 kV or greater then there may be an a.c. interference risk the distance between buried pipelines and overhead power cables should be established. It should be borne in mind that even at very low a.c. potentials a.c. corrosion can occur in very low soil resistivity environments.

It should be borne in mind that even at very low a.c. potentials, a.c. corrosion can occur in very low soil resistivity environments

One parameter is the a.c. pipe to soil potential. The a.c. pipe to soil potential would give an indication as to the levels of possible interference.

Routine CP monitoring checks should include a.c. voltage measurements for example If a.c voltages in excess 2 to 3V are present, and it is clear that a pipeline is routed near overhead pipelines, then that would indicate additional tests should be carried out.

The use of portable a.c. coupons may be considered to ascertain likely values of a.c. current density at certain locations. The use of a.c. coupons supplemented by the use of data loggers will assist in providing good confirmatory data to assess the level of risk.

NACE SP 21424 advises that “For existing pipelines, the a.c. corrosion evaluation process recommends an initial analysis involving factors such as pipeline history record, proximity assessments, CP data and evaluation of existing pipeline and coupon data, etc. If the initial analysis indicates that an a.c. corrosion risk is present, the initial analysis should be followed by a detailed analysis involving a.c calculations and/or a.c. measurements, evaluation of historical CP data and abnormalities, d.c. interference, inline inspection results and other existing data relevant for the analysis.

6.8 Defect Investigations

Often when in line inspection features are exposed there is not an adequate level of testing undertaken to establish the cause of any external corrosion or metal loss feature.

The tests that are carried out when exposing and examining intelligent pig features should include photographic records of any defect and measurements of pit depth and dimensions by suitably qualified inspectors. The inspection should also include details of the a.c/ d.c. current density at the defect location, the a.c. and d.c. pipe to soil potential, soil composition and resistivity checks and tests for bacterial activity.

The damaged area or area containing any metal loss feature should be cleaned prior to the initial inspection with a suitable technique e.g. water and lint cloth or 100 grit emery paper. The cleaning procedure should comply with the operator's specific requirements for such evaluations. Visual identification of the damage type, (include photographs, as appropriate) should also be included in any investigation.

Pipeline wall thickness measured at selected locations adjacent to the damage using an ultrasonic wall thickness meter with a measurement accuracy not less than 0.1mm. In the case of seamless pipe, measurements shall be made using a 20mm reference grid in a zone 60mm wide surrounding the damaged area.

Depth of any pitting using appropriate inspection tools including axial and effective length of damage.

The following tests should be carried out by appropriate trained and approved personnel: -

- Measure pipeline d.c. 'ON' and a.c. pipe to soil potential.
- Record a.c. and d.c. current density with a portable 1cm^2 coupon.
- Measure any defect dimensions with pit depth gauge and Vernier. (Measurement techniques may improve over time).
- Note date and time of tests. If possible, use a data logger to record the time dependent variation in a.c./d.c. potential and current density over a 24-hour period.
- Confirm CP status at test facilities located on each side of defect investigation including a.c. current density and voltage and gather information on CP system T/R unit operational status.

All the above tests should be carried by an experienced CP engineer

A sample of soil should be removed from around the pipeline and placed in a plastic container with an airtight seal. The soil sample should be analysed in accordance with DIN 50929-3 [23].and the soil resistivity also determined. Bacterial testing should be carried out in accordance with TM 0194[24].

The coating system and metal loss features should be examined by a suitably inspector, and adhesion tests carried out to ensure that any coating is effectively bonded to the pipeline and has not disbonded from the pipe surface. The coating film thickness should be recorded.

Once all relevant information and photographs have been recorded, sufficient coating should be removed to assist with the inspection procedure. At the initial inspection stage, minimal coating should be removed, sufficient to facilitate the inspection requirements.

6.9 Soil Resistivity

A soil resistivity survey should be carried out in accordance with ASTM G57 [25] using the Wenner 4 pin method on pipelines where there is considered to be an a.c. interference risk and the survey should be conducted along the entire pipeline route to ascertain if there are any areas of low soil resistivity e.g. salt marshes. Soil resistivities less than 25 Ohm m are high risk locations for a.c. corrosion and those less than 10 Ohm m are very high-risk locations. To assess a.c. corrosion risk the soil resistivity at the pipeline depth should be recorded and information obtained on whether any selected backfill was used.

Ideally, soil resistivity measurements should be carried out at 500m intervals along a pipeline route, but if any areas of possible low resistivity are identified by a visual inspection of the route, then resistivity measurements at more frequent intervals should be conducted.

If there are a.c. coupons installed, then high current densities will be indicative of low soil resistivity locations. For pipelines installed by the open cut technique and buried at typical pipeline depths of 1.2m in field and 1.7m at road crossings, then the soil resistance values should be determined at 0.5, 1.0, 1.5, 2.0, 2.5 and 3.0m spacings. The mean and layer resistivities should be calculated for each location

The Barnes Layer resistivity [26] at the pipeline burial depth should be used to ascertain the nature of the a.c. corrosion risk.

It should be noted that should soil resistivity data will be required to model GPR for pylons and substations close to a pipeline route. The soil resistivity data at depth will be required and soil resistivity data at varying pin spacings up to 60m may be required to complete mathematical models.

6.10 Design Requirements

If a pipeline has been identified as being at risk of a.c. interference, then an a.c. mitigation system should be designed and installed once a review of the level of interference has been evaluated. It is important that if an a.c. interference risk has been identified and a.c. corrosion is considered to be likely, then any mitigation system should be installed as soon as possible after identification of the risk, due to the high rates at which a.c. corrosion can occur.

Two approaches have been adopted in the past; one is an empirical approach where personnel experienced with a.c. interference issues on pipelines decide where to install mitigation systems e.g. zinc earthing.

The mitigation system is then designed and installed at the locations where high levels of a.c. interference have been recorded. The locations for the earthing system are normally determined by the availability of CP test facilities and where there is an existing pipe connection.

The design requirements should be based upon the guidance given in BS EN ISO 18086. Mitigation of a.c. interference would generally consist of the installation of earths connected to the pipeline at CP test facilities via suitably rated d.c. decoupling devices. The further away from the pipeline that an earth can be installed the lower will be the resistance of the earth until the electrode of a given set of geometries is at remote earth. However, land ownership issues frequently mean that the a.c. mitigation earths are installed at the edge of the pipeline wayleave particularly on retrofit mitigation systems.

The d.c. decoupling devices should be capable of carrying the prospective a.c fault current at very low voltages.

The d.c. blocking voltage would generally be -3V to +1V.

A.C. coupons should also be installed at all CP test facilities to provide the ability to monitor the a.c. interference risk along the entire pipeline. A typical test post arrangement is shown on Figure 8

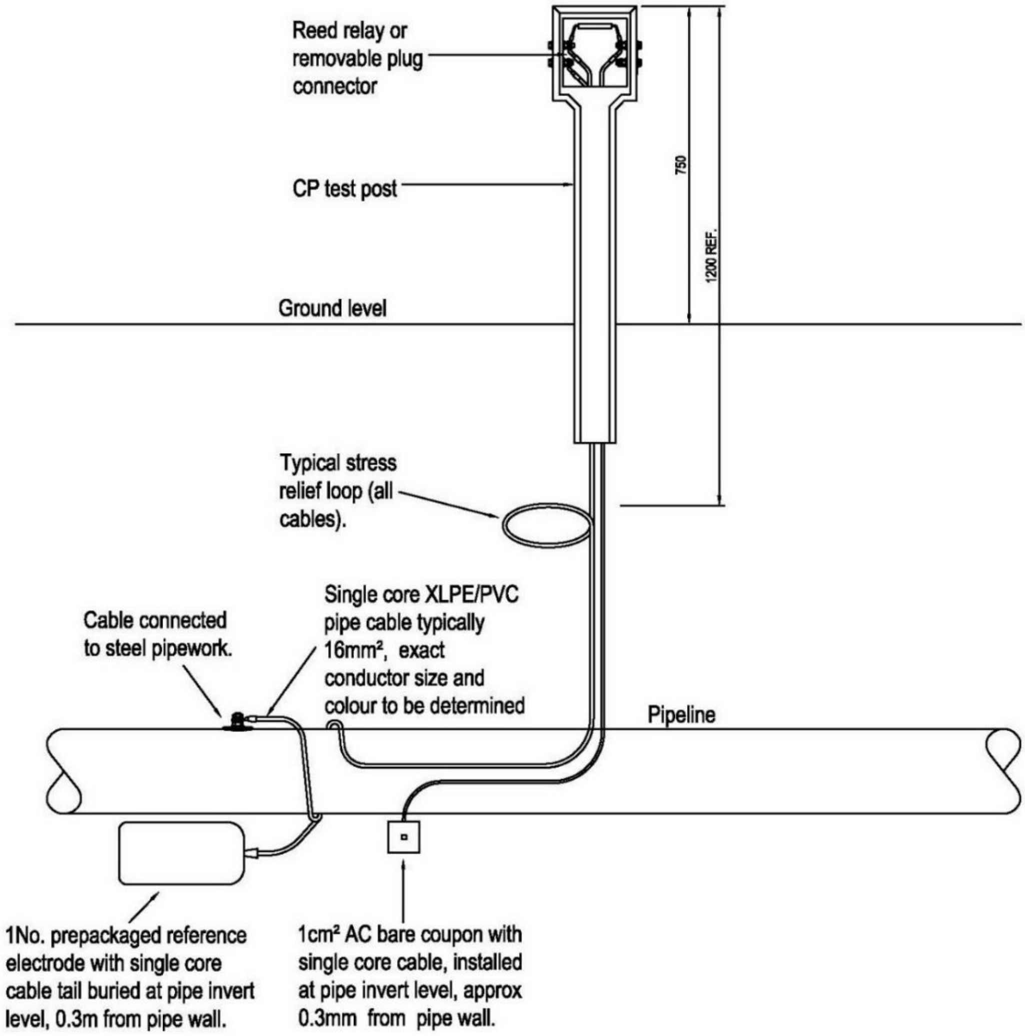


Figure 8 Typical a.c. interference monitoring test facility

The earths would typically be installed at high risk locations in terms of current density and routed along the pipeline length for a distance of approximately 150m, often longer depending upon the assessment of a.c. interference Zinc ribbons should be installed on the side of the pipeline between the power line and the pipeline to achieve the optimum effect.

The details of a typical zinc ribbon installation are given on Figure 9.

Once the earths have been installed, the a.c. interference risk should then be monitored using the a.c. coupons installed by undertaking data logging of a.c. and d.c. current density over a representative period of time.

AC corrosion monitoring standards advises that a representative period of time is 24 hours, but experience has shown that at the weekends the load on power lines decrease significantly and it is advisable therefore that monitoring is undertaken over a 7-day period to provide an accurate assessment of risk. It should be noted that the loads on the power lines would be higher during the winter months and thus data logging on high risk pipeline locations should include monitoring during winter periods.

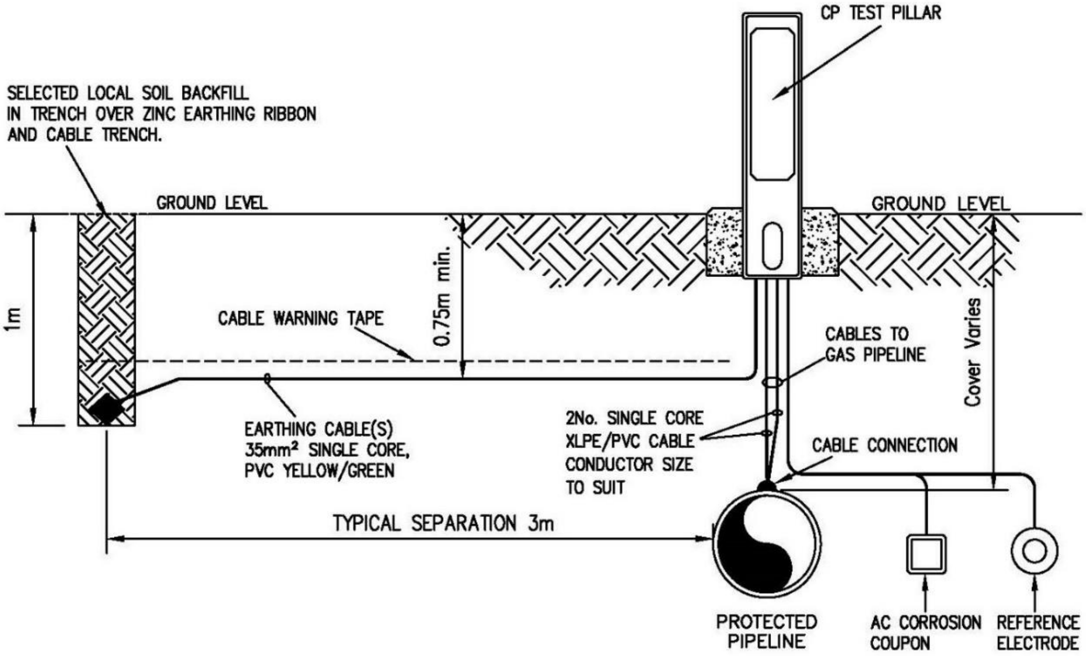


Figure 9 Typical View of Zinc ribbon installation

6.11 Over the Line Surveys

If there is a requirement to install an a.c. mitigation system on an existing pipeline. Then once a mitigation system is installed it may not be possible to undertake effective over the line surveys in the future e.g. CIP or DCVG.

This is because the decoupling devices used to d.c. isolate a.c. mitigation system earthing from the pipeline can affect over the line CIP survey data. The decouplers are capacitive devices and may discharge d.c. current to the pipeline during the 'OFF' cycle of any CIP survey.

Thus, where a PCR or SSD is employed in an a.c. mitigation system earth, there may be a limited potential shift between the 'ON' and instant 'OFF' pipe to soil potential during CIP surveys.

In the case of a PCR installation at an I/J for example, this effect, i.e. limited potential shift between the 'ON' and instant 'OFF' potential, can exist over a distance of about 2 to 3km from an I/J, based upon experience.

In the case of DCVG surveys, the earthing systems once installed will also limit the ability to perform DCVG surveys. In such situations, consideration may be given to the use of ACVG surveys. However, these too have their limitations where earthing is installed as the earthing limits the signal spread

Where the a.c. voltage on a pipeline is below safe limits i.e. less than 15V rms and provided the safety risks to survey personnel have been fully evaluated then consideration may be given to disconnection of decoupling devices over sections of a pipeline system to ensure instant OFF potentials can be recorded during a CIP/DCVG survey.

It will be essential that a CIP and DCVG survey is conducted prior to installation of any new a.c. interference mitigation system on existing pipelines to locate coating defects and identify possible a.c. corrosion locations.

This is so that operators have a record of the actual CP status of the pipeline prior to any installation of an a.c. mitigation system and all coating defects on a pipeline are identified. On a non pigable pipeline it is essential that that such surveys are performed, as an a.c. mitigation system could affect the ability to perform over the line surveys.

A DCVG survey will be required to locate coating defects that may be susceptible to a.c. interference.

Conventional DCVG surveys require a minimum potential shift of at least 250mV at the CP test facilities. However, it is recommended that a potential shift of at least 500mV is achieved at the DCVG current injection location when a DCVG survey is carried out on pipelines where there is an a.c. corrosion risk to maximise the coating defect identification. A proven switch to be able to identify the feature size that is being looked for at the depth and relative soil conditions that are being surveyed should be obtained.

It is important for all DCVG defects, no matter how small in terms of percentage IR, are accurately located and recorded prior to any a.c. mitigation system being installed.

It should be noted that in low soil resistivity environments that it may not always be possible to locate all coating defects using the DCVG technique and that some coating defects may remain undetected. This is because the DCVG survey is not as sensitive in low soil resistivity areas and small coating defects can be missed. The use of alternative defect location techniques may be considered e.g. ACVG.

In the case of existing pipelines where a new a.c. power system is to be installed close to the pipeline, consideration should be given to the effect the electromagnetic interference will create on the pipeline and the ability to undertake pipeline depth and GPS surveys in the future. It may be prudent to undertake any depth and GPS location surveys prior to any new power system energisation.

6.12 Monitoring Facilities

On pipelines where a.c. interference has been identified, test facilities should contain a.c. coupons specifically designed for use on pipelines, complete with factory connected cable of a minimum conductor size of 10mm^2 and of a colour that will enable ease of identification as an a.c. coupon.

It is essential that a.c. coupons are identified by a completely different colour cable to any d.c. coupons to avoid confusion. A permanent reference electrode should also be installed at the same location as any coupon.

If the a.c voltage levels are expected to approach unsafe levels and the general public may be exposed to an enhanced risk then dead front CP posts, which require access with a key should be considered.

6.13 AC Mitigation System Earthing Facilities

On pipelines where a.c. interference has been identified and it is proposed to install an a.c. mitigation system, at least two cable to pipe connections should be installed at each test facility where a zinc earth will be installed.

One cable to pipe connection should be used to carry the a.c. current that will flow through any earth electrodes and the other cable to pipe connection used for potential measurement purposes and not be used to carry current. This is to avoid any potential measurement errors due to IR drop in the current carrying cable.

The minimum conductor size for the potential measurement cable should be 10mm^2 single core and that for the pipe current carrying cable should be sufficient to carry the rated fault current for any SSD installed and should be at least 16mm^2. On pipelines were there are just CP monitoring facilities only one pipe connection is required.

6.14 AC Mitigation System Earthing Material

Zinc ribbon anodes complying with ASTM B 418 Type 1 [27] are generally installed as part of the mitigation system. If connected to the pipeline via a decoupling device or SSD then the impedance of the earth should be sufficient to discharge a.c. current to earth and provide effective mitigation.

If earthing material other than zinc is used for earthing purposes, then consideration should be given to the effects any dissimilar metals may have on the pipeline CP system. If a decoupling device was to fail short circuit, then the earth may be connected to the pipeline and if not compatible with the pipeline CP system e.g. copper it could result in galvanic corrosion or reduction in CP levels.

Some designers specify material other than zinc to be used as an earth material e.g. copper wire in petroleum coke filled sock or copper earthing tape. The latter materials will provide a galvanic corrosion risk if directly connected to a pipeline when a decoupling device fails short circuit and pipeline operators should also consider the latter risk when selecting earthing material. Where earthing materials other than zinc are employed pipeline operators should consider enhanced monitoring to ensure any galvanic risk is monitored.

6.15 In-Line Inspection

ILI is an effective means of assessing whether a pipeline system is at risk of a.c. corrosion and whether there is an ongoing risk. Operators should review the ILI frequency based upon the a.c. corrosion risk. On pipelines that are susceptible to a.c. interference then the ILI frequency would need to be assessed and would generally be in excess of that normally adopted for a pipeline system where the a.c. interference risk is controlled or limited.

Operators should not however just rely on ILI as the only means of detecting and managing the a.c. corrosion risk as the technique does have its limitations and may not detect all a.c. corrosion features.

The accuracy and reporting of defects should be confirmed with the ILI vendor to provide operators confidence in assessment of in line inspection results in determining a.c. or general corrosion risks. If a pipeline has a known a.c. interference risk, then the ILI vendor should be informed prior to conducting any work and carrying out defect assessment studies.

The in-line inspection assessment should ascertain if there has been any growth in the smaller size defects, which are typically caused by a.c. corrosion. If there has been defect growth between successive pig runs, then this could indicate a risk of a.c. corrosion and require further investigation. The rate of defect growth may also not be linear with time as the levels of a.c interference may have changed between in line inspection intervals. The growth assessments can be inaccurate if linear defect growth is assumed and an assessment of the possible variation in a.c. interference levels between inspection should be undertaken.

6.16 Monitoring of AC Mitigation Systems

Once an a.c. monitoring and mitigation system is installed it should be monitored in accordance with the recommendations detailed in section 10.0. It has been known for some pipeline operators to install a.c. mitigation systems, but not effectively monitor their performance once installed. It is essential that once an a.c. mitigation system is installed it is monitored and maintained in accordance with this GPG and the guidance given in BS EN ISO 18086.

Proprietary remote monitoring systems are also often installed on pipelines susceptible to a.c. interference and their use is recommended. However, they should not be considered to be data loggers as they will often only record one reading a week over a 1 second period. Thy will provide functional performance and alarm checks only but will not act as data loggers.

7. AC INTERFERENCE DESIGN ON PIPELINES

7.1 Introduction

The requirements of the pipeline design standard in relation to a.c. interference risk on pipelines outlined in section 7.0 of this GPG should be followed.

The a.c. interference and monitoring design would be undertaken in conjunction with the design of the pipeline CP system. Thus, the requirements of any pipeline operators' specific standards plus those of BS EN ISO 15589-1 in relation to the CP system design and BS EN ISO 18086 for the a.c. interference design should be included in the evaluation of a.c. interference risk and design of any a.c. mitigation system. The supplementary guidance provided in this GPG should also be followed as appropriate.

The design objective is to ensure that the a.c. discharge current density at coating defects on any pipeline system is less than 30 Am^{-2} at the maximum power line operating loads that are likely to be experienced, and that the a.c. voltage on any pipeline is less than 15V rms and at a value that will ensure that the a.c discharge current density does not exceed 30 Am^{-2}. The a.c. voltage necessary to achieve the specified a.c. discharge current density is often only in the region of 1 to 5 Vrms.

The electrical safety risks associated with AC interference are detailed in BS EN 50443 and UKOPA/TBN/005

7.2 Route Selection

Consideration of the risks of a.c. interference should form an integral part of the route selection process for any new pipeline system. Wherever possible, pipelines should be routed as far as possible from overhead power lines. Thus, pipeline routes should be selected to avoid or minimize a.c. interference and an assessment of the a.c. interference risk included in the route selection process.

Where parallel runs of pipelines and power lines occur, voltage peaks may occur where there are discontinuities such as insulating joints, a junction of two or more pipelines, and at abrupt changes in power line to pipeline configuration or cable transposition locations.

Pipelines should not cross power lines at acute angles; ideally, they should cross at right angles.

7.3 Mathematical Modelling

Mathematical modelling using specialist proprietary software is required to determine the short-term interference levels on pipelines from a fault on overhead power line pylons, at a HV substation or from buried cable joint bays.

It is recommended that selected locations along a pipeline route are modelled to determine the maximum touch potential that will be experienced on the pipeline during fault conditions. If the touch potential limits exceed the required limits, then additional models may need to be undertaken.

Pipeline CP TR units may also act as earth locations along a pipeline route with fault currents discharging to earth through the CP groundbed. Modelling should be undertaken to assess the GPR within the vicinity of any CP groundbeds as part of any a.c. interference study.

However, caution should be exercised as the models created may not be accurate as a number of assumptions are made when creating the model. The soil resistivity value has a significant effect on ascertaining the risk of a.c. corrosion.

Experience has shown that whilst mathematical models can be useful, they may not always produce a mitigation system design that will be fully effective and changes to the earthing arrangement on a pipeline may be required in the future following commissioning and subsequent monitoring data.

Operators should validate any mathematical model by undertaking appropriate a.c. monitoring on a pipeline system following installation of an a.c. mitigation system or operation of any new cable system.

Mathematical modelling requires accurate information on the pipeline and power line route, details of the power system including rated and maximum loads, power cable pylon construction and details of the screen wire.

7.4 Empirical Assessments

On shorter pipeline systems and some longer ones, e.g. 20 to 30 km, a.c. interference mitigation schemes have, in the past, been designed based upon experience. This is where an experienced designer/corrosion engineer evaluates the a.c. interference risk from a knowledge of the pipeline route in relation to the power line route and determines if and where any earthing is required.

The earths would be connected to the pipeline via decoupling devices and placed at selected CP test facilities along the pipeline route.

During the commissioning phase detailed testing including data logging is then undertaken to confirm the a.c. discharge current densities are within the required limits. The empirical assessment method has proved successful in the past on UK projects. However, as the number of companies capable of offering mathematical modelling services has increased empirically designed a.c. mitigation systems are not often employed.

Empirical assessments cannot replace modelling for determination of short term a.c. interference levels. If possible, it is recommended that mathematical modelling be conducted but it should be taken into account that models may not always be accurate and often there is a difference between values determined in practice and those provided by mathematical models.

7.5 Monitoring Facilities

On pipelines where a.c. interference has been identified or is considered to be a risk the CP system monitoring facilities should contain a.c. coupons specifically designed for use on pipelines complete with factory connected cable of a minimum conductor size of 10mm^2 and of a colour that will enable ease of identification as an a.c. coupon.

On new pipeline construction projects cable connection plates rather than pin braze connections should be used. The connection plates should be fillet welded to the pipeline in accordance with an approved Weld Procedure Specification. Permanent reference electrodes should also be employed.

Where cables entering the CP monitoring facilities are not in accordance with the specified colour code for the particular company, they should be identified by proprietary cable markers.

7.6 Installation of AC Mitigation and Monitoring Systems

Once a pipeline system is installed it is important to obtain base line date on the levels of a.c. interference levels that exist on a pipeline prior to installation of any a.c. mitigation system.

However, any a.c. interference mitigation system should be connected to the pipeline as soon as possible after pipeline installation. Once a new pipeline is installed the pipeline coating will exhibit its highest impedance and gradually absorb moisture over time to reduce the coating impedance.

The coating impedance will then reduce and as the pipeline coating impedance reduces this will allow a.c. current to flow through the coating as well as at coating defects. Where the pipeline coating has a high impedance then any a.c current discharge will concentrate at exposed steel surface at coating defects.

It is important that any subsequent a.c. monitoring and mitigation system design includes for suitable test facilities to monitor a.c. interference levels.

The designer should consider whether there is a requirement for the installation of ER probes or similar devices to monitor corrosion rate as part of the design process.

Where employed, coupons should be designed so that they can be removed for subsequent laboratory examination at a later date and the date of coupon installation should be accurately recorded.

A.C. coupons if complete with factory connected cable can be excavated and removed for inspection at some time in the future and sent to a test laboratory for metallurgical examination. This will provide an indication as to whether or not a.c. corrosion has been on going and the possible extent.

Zinc ribbon should be installed so that it is located between 2 to 6m from the pipeline to minimise the earth resistance and also so that it is installed between the pipeline and the power line i.e. on the side of the pipeline facing the power cables. The zinc earth depth of burial would be typically greater than normal agricultural depth.

7.7 Remote Monitoring

On new pipelines where an a.c. interference risk has been identified, then at least one remote monitor should be employed and installed at a high risk a.c. current density location. The designer may select additional remote monitoring locations once the detailed design has been completed.

The remote monitoring device should monitor the a.c. and d.c. current densities, a.c. pipe to soil potential and d.c. pipe to soil potential.

7.8 Commissioning

It is important that following installation of an a.c. monitoring and mitigation system that all necessary pre-commissioning checks are conducted. The a.c. mitigation system should be commissioned to confirm it meets with the design specification and a fully detailed commissioning report produced.

The following tests should be performed at CP monitoring locations as part of the commissioning checks;

- a.c. pipe to soil potential
- d.c. pipe to soil potential ‘ON’/’OFF’
- a.c. current density
- d.c. current density
- Coupon instant ‘OFF’ potential

- T/R unit output levels
- A.C. current discharged to earth through any earths

All measurements should be performed with calibrated test equipment capable of measuring true rms values.

A.C. and d.c. current density readings should be taken on all a.c. coupons

The current flow through all PCRs or decoupling devices should be recorded.

Data logging should be performed to determine the time dependent variation in both a.c. and d.c. pipe to soil potential and current density.

The readings should be performed at all test facilities where the a.c. current density recorded during commissioning exceeds 10 Am^{-2}.

8. MONITORING

BS EN 15280 advises in relation to a.c. interference that “Measurement frequencies shall be in accordance with those given in BS EN 12954. As the corrosion risk is higher on a pipeline with an a.c. voltage, the operator shall pay special attention to the frequency at which measurements are taken and how the measurements are performed.”

BS EN ISO 18086 provides similar guidance except it refers to the maintenance frequencies given in BS EN ISO 15589-1. Thus, as BS EN ISO 15589-1 is the latest standard in relation to CP of buried pipelines it is considered that the monitoring frequencies for pipelines subject to a.c. interference should at least be based upon the minimum requirements in BS EN ISO 15589-1 rather than BS EN 12954.

Pipeline operators should note that BS EN 12954 and BS EN ISO 15589-1 relate to cathodic protection of buried and immersed pipeline systems .BS EN 12954 was issued in 2001 when the risk of a.c. interference on pipeline systems was not widely known. BS EN ISO 15589-1 includes additional guidance but does not it is considered specifically address a.c. corrosion risks.

Failure of a CP system would generally not lead to high rates of corrosion on a pipeline unless it resulted from d.c. interference. However, failure of an a.c. corrosion mitigation system or the presence of a.c. interference on pipelines can in certain circumstances lead to corrosion rates considerably in excess of the free corrosion rate for steel in soil and an increased frequency of monitoring is recommended for pipelines affected by a.c. interference. The pipeline operator should determine the inspection frequency based upon the risks to a particular pipeline system from a.c. interference. The monitoring frequency should also be subject to periodic review during the lifetime of the pipeline system as additional sources of a.c. interference may be present and could affect the a.c. corrosion risk. Table 9 in this GPG provides guidance on recommended inspection frequencies for a.c. mitigation and monitoring systems.

A.C. interference monitoring should be combined with routine CP system monitoring to maximise resources.

It is also recommended that for pipelines where an a.c. corrosion risk has been identified that a suitable remote monitoring system should be employed. The remote monitor or monitors should be located at high risk locations to warn of alarm situations i.e. situations where there is a risk of a.c. interference and corrosion.

The use of portable data loggers to determine the time dependent variation in a.c. current and voltage at high risk locations in terms of a.c. current density and voltage should also be undertaken at periodic intervals at the same time as routine CP/ A.C. monitoring checks. The data logger measurements should typically be carried out at 1 to 10-minute intervals over a 7-day period.

If an a.c. voltage or current density reading is only taken once every 6 months at CP test facilities or on some pipeline systems once every 5 years at all CP test facilities that inspection frequency would be insufficient to identify any significant a.c. interference risks. Data logging where employed should take place over a representative period of time e.g. 7 days to provide valid data.

It is recommended that on pipelines susceptible to a.c. interference that data loggers are employed periodically at high risk locations, where the highest levels of a.c. current density have been recorded to confirm the time dependent variation in a.c. current density.

Thus, as part of any 6 monthly maintenance survey the use of one, two or more data loggers to record long term current density data would be of use to assist in an assessment of the a.c. corrosion risk

Nature of Test
Reference electrode calibration
Grounding system checks i.e. earth resistance measurements on decoupling devices
PCR and decoupling device AC current measurements
CP test station a.c. /d.c. potential measurements ‘ON’/’OFF’
A.C./D.C. current density measurements at a.c./d.c. coupons
‘OFF’ potential measurements on pipeline system
TR system checks single source systems
TR system checks multiple source systems
Data Logging at high risk locations to confirm current densities are within prescribed limits
Remote monitoring
Calibration of remote monitoring systems

Table 9 Recommended test and inspections for pipelines with an a.c. monitoring and mitigation system installed (BS EN ISO 15589-1)

It is important that all measurement equipment on pipelines affected by a.c. interference has the ability to record true rms data and has sufficient levels of a.c. rejection on the d.c. measurement circuit to ensure accurate d.c. pipe to soil potentials are recorded.

The a.c. current flow through each decoupling device should be recorded at regular intervals to ensure that the device is still effective. If there is no a.c. current flow, then there may be a problem with the zinc earth that needs investigating.

8.1 Remote Monitoring

On pipelines affected by a.c. interference it is recommended that a suitable remote monitoring system is installed to record a.c. and d.c. pipe to soil potentials, a.c. current density and d.c. current density and provide an alarm indication. The remote monitors should be installed at one or more high risk a.c. interference locations along a pipeline route.

Remote monitoring devices should be calibrated at regular intervals to ensure that the data obtained is accurate. The calibration can be carried out at CP test facilities using calibrated test equipment rather than require the removal of the device and its return to the manufacturer. Remote monitor alarm settings should be set at appropriate values in terms of all parameters that are monitored, in particular a.c. current density.

Most remote monitoring devices will take only one reading or slightly more readings per week. The reading is often taken over a 1 second interval by the devices that are generally employed in the UK. If the remote monitoring interval is set at once per week then the time the measurements are taken should be one that reflects the maximum anticipated level of a.c. interference.

This would be say at 16.00 hours and not 01.00 hours in the morning when the load on a power line system would be expected to be low. It is important to confirm that any remote monitor records data at an appropriate time. The alarm levels for any remote monitoring system shall be set at values that would warn of an increased level of risk. This is both in terms of a.c. and d.c. interference.

8.2 Nature of Tests on Pipelines affected by AC Interference

The following tests should be performed at CP monitoring locations on pipelines affected by a.c. interference:

- a.c. pipe to soil potential
- d.c. pipe to soil potential
- a.c. current density
- d.c. current density at a.c. coupon
- Coupon instant 'OFF' potential
- a.c. current flow through any earths/ Polarization Cell Replacement (PCR)

All measurements should be performed with calibrated test equipment and with multimeter capable of measuring true rms values. Current density readings through all coupons and probes should be recorded.

Data logging of high risk a.c. current density locations should be conducted on a periodic basis to confirm the minimum, mean and maximum current densities at selected test facilities.

Where decoupling devices are installed and connected to earth systems to discharge a.c. current off a pipeline the a.c. and d.c. current output from the earth should be recorded together with the a.c. voltage the device operates at.

If PCR's are installed across I/F's or I/J' the current flow through the PCR should be recorded together with the a.c. voltage each side of a PCR. The corrosion rate from any electrical resistance probes on a pipeline should be noted.

The resistance of all earths installed on a pipeline to discharge a.c current should be monitored on at least a 6-monthly basis. The resistance or impedance is simply the a.c pipe to soil potential divided by the a.c current through the decoupler. A sudden increase in earth resistance would be indicative of failure of the earth. The typical resistance values of zinc earths would be in the range 1 to 5 ohms.

At locations that exhibit current densities close to or above the $30Am^{-2}$ maximum current density level data logging should be performed at representative test facilities and the data logging should take place over at least a 24-hour period and preferably a 7-day period. Data loggers should be capable of recording mean, maximum and minimum values.

In the case of a.c. interference monitoring on pipelines close to overhead power lines the frequency of monitoring or logging should be at least once every 10 minutes. In the case of data logging on pipelines close to a.c. traction systems the data logging frequency should be increased to at least once every second to identify transient events.

8.3 Data Interpretation

It is recommended that the data from any a.c. interference monitoring, and mitigation systems should be interpreted by a Level 4 BS EN ISO 15257 Certified Senior Cathodic Protection Engineer, or other competent engineer approved by the pipeline owner/operator.

The pipeline operator should however confirm that personnel employed in interpreting data, even if BS EN ISO 15257 Level 4 certified, have the required levels of experience and competency in assessment of a.c. interference risks on pipelines affected by a.c. interference.

8.4 Documents

The design of any a.c. mitigation system should comply with the relevant codes and standards identified in this GPG. It is important that following on from any maintenance survey that a fully detailed report is issued. The report should contain the monitoring data as required in this GPG, the remote monitoring system data and any data logging results.

It is important that an operations and maintenance manual is provided for any a.c. mitigation and monitoring system and that the requirements of the O and M manual are followed in relation to maintenance of a specific system.

8.5 Corrosion Rate Measurements

The current density measurements at a.c. coupons will give an indication of the level of risk of a.c. corrosion but will not give an indication of the rate of corrosion that is occurring on the pipeline system. There are devices that can be used to ascertain corrosion rate, namely ER probes or perforation probes, and these are identified in BS EN ISO 18086.

Operators would need to assess, based upon the nature of the risk, whether it is necessary to install such monitoring equipment on a pipeline. In the UK the use of perforation probes has not been adopted but ER probes with elements of surface area 1 cm^2 have been used. It is important that the ER probe has a 1cm^2 exposed surface area as this has been shown to be the coating defect surface area that exhibits the highest a.c. corrosion risk

The ER probe element thickness varies generally from 500 microns to 1000 microns. The thicker the element the lower the sensitivity in terms corrosion rate. However, if the pipeline has an ongoing a.c. interference risk and a.c. corrosion is occurring then ER probes with a thinner element will exhibit a reduced life and once the element thickness has been lost the coupon will have effectively failed.

Remote monitoring ER probes are available that can record, corrosion rate, remaining probe thickness, a.c. and d.c. current density, a.c and d.c. pipe to soil potential and coupon spread resistance. Data can be accessed remotely, and readings taken at 1 to 2-hour intervals.

The devices are solar powered which gives the ability to take readings at regular intervals. Alarm set points can also be set,

8.6 Weight Loss Coupon Examination

One method of assessing the risk or magnitude of the a.c. corrosion rate on a pipeline is to carry out laboratory examination of a coupon that has been installed to monitor a.c. current density. It is important to know the date of coupon installation and the coupon dimensions at the time of installation. The coupon can then be removed for laboratory examination to determine if any metal loss has occurred.

The technique suffers from the limitation that a linear corrosion rate would be calculated, which may not be the case in practice if a.c interference have increased during the period any coupon was installed. Thus, the estimate rate may not reflect the actual rate of corrosion that may be occurring at the time of excavation.

The local soil should be analysed in accordance with DIN 50929-3 and coupon analysis carried out in accordance with BS EN ISO 8407 [28]. It is important that the soil analysis includes measurement of soil resistivity.

The analysis of coupons will help ascertain if there has been any ongoing corrosion on the pipeline system at similar sized coating defects in that area.

The surface appearance of an a.c. coupon exposed to high levels of a.c. interference is given in Figure 10

Figure 10 Picture of a.c. coupon on which corrosion had occurred

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Appendix A: Abbreviations

Abbreviation	Meaning
3LPE	Three Layer Polyethylene
A	Amps
AC	Alternating Current
ACVG	Alternative Current Voltage Gradient
AGI	Above Ground Installation
BS	British Standard
CIGRE	The International Council on Large Electric Systems (in French: Conseil International des Grands Réseaux Électriques, abbreviated CIGRÉ
CIP	Close Interval Potential
CP	Cathodic Protection
CSA	Canadian Standards Association
DC	Direct Current
DCVG	Direct Voltage Current Gradient
EN	European Norm
EPR	Earth Potential Rise
ER	Electrical Resistance
FBE	Fusion Bonded Epoxy
GPG	Good Practice Guide
GPR	Ground Potential Rise
HDD	Horizontal Directional Drill
HSE	Health and Safety Executive
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electronic and Electrical Engineers
IET	Institute of Engineering Technology
IGEM	Institute of Gas Engineers and Managers

I/F	Isolation Flange
I/J	Insulation Joint
ILI	Inline Inspection
ILIV	Inline Inspection Vehicle
INGAA	Interstate Natural Gas Association of America
ISO	International Standards Organisation
Ja.c.	a.c. discharge current density Am^{-2}
Ja.c.	d.c. current density Am^{-2}
kA	Kilo Amps
kV	Kilo Volts
LFI	Low frequency Induction
m	Metre
MAHP	Major Accident Hazard Pipeline
MFL	Magnetic Flux Leakage
mV	Millivolts
NACE	National Association of Corrosion Engineers
OHL	Overhead Line
PCM	Pipeline Current Mapper
PD	Published Document
POD	Probability of Detection
POI	Probability of Identification
PSR	Pipelines Safety Regulations
rms	Root Mean Square
SSSI	Site of Special Scientific Interest
TP	Test Point
TS	Technical Standard
V	Volts

Appendix B: Useful Information Definitions

The definitions applying to this GPG are given below:

A.C. corrosion: corrosion caused by alternating current, which originates from an external current source.

A.C. discharge device: a device blocking d.c. current but allowing the flow of a.c. current; used in the connection between a cathodically protected pipeline and an earthing electrode.

A.C. Coupon: A circular 1 cm^2 surface area representative metal sample used to quantify the extent of corrosion, current discharge off the pipeline both a.c. and d.c. or the effectiveness of applied cathodic protection.

Anode: Electrically – the positive electrode of an electrochemical cell, which emits current in the form of ionic discharge and corrodes and produces electrons. In the cathodic protection context, a device used to transmit protective current through an electrolyte to the metal to be protected (the cathode).

Bond: A piece of metal, usually in the form of rectangular strip, circular solid wire or stranded conductor, usually of copper, connecting two points on the same or on different structures to prevent any appreciable change in the potential of one point in respect of the other.

Capacitive coupling - the transfer of alternating electrical signals or energy from one segment of a circuit to the other using a capacitor

Cathode: Electrically – the negative electrode of a cell. In the cathodic protection context, it is the term given to the structure to be protected and where the cathodic reaction occurs, which in soil is reduction of dissolved oxygen in water.

Continuity bond: A bond designed and installed specifically to ensure the electrical continuity of a structure. This may be permanent or temporary, in the latter case it is used to connect two sections of a structure, which would otherwise be disconnected during the course of modification or repair.

Copper/copper sulphate reference electrode: A reference electrode consisting of copper in a saturated copper sulphate solution.

Coupon: A representative metal sample of known bare surface area used to quantify the extent of corrosion or the effectiveness of applied cathodic protection or a.c. interference.

Corrosion rate: the rate of corrosion (metal dissolution). Corrosion rate is expressed as weight loss per unit of metal area and unit of time (g/m^2 and year) or as loss of metal thickness per unit of time (µm/year = 0,001 mm/year). Weight loss can be recalculated into loss of metal thickness. The rate of localised corrosion is usually expressed as depth penetration per unit of time (µm/year).

Current density (on metal surface): current per unit metal surface area, usually expressed as Am^{-2}

DC decoupling device: A protective device that will conduct D.C. current when pre-determined threshold DC voltage levels are exceeded but will allow A.C. current to flow at all A.C. voltages.

Depolarisation: The change in the potential of the cathode as a result of cessation of current flow and is a time dependent process.

Direct current voltage gradient (DCVG): An above ground surveying system that is used for the location and sizing of coating defects on buried pipelines. During DCVG surveys, the cathodic protection current is pulsed. A sensitive milli-voltmeter and two copper-copper sulphate reference electrodes, placed about one metre apart by the surveyor, are typically used for surveying purposes. Thus, the potential gradient associated with coating defects can be identified and assessed to provide a qualitative assessment of defect size.

Drain point: The location of the negative cable connection to the protected structure through which the protective current returns to its source.

Earthing resistance: the electrical resistance between a metal surface (e.g. the steel surface in a coating holiday on a buried pipe, or an earthing electrode or an a.c. power line pole foundation) a remote earth.

Earth Potential Rise (EPR): the increased potential of an a.c. tower earthing point and the surrounding soil due to earth currents, especially the high fault current at a phase-to-earth fault in an a.c. power line tower. The potential rise may also be caused by a lightning strike to the tower, and which may result in a phase-to-earth fault. The EPR is a function of the a.c. tower earthing and the soil resistivity.

Free corrosion potential (natural potential): The potential of a corroding surface in an electrolyte relative to a reference electrode.

Groundbed: A system of buried or submerged electrodes connected to the positive terminal of an independent source of direct current, in order to lead to earth, the current used for the cathodic protection of a buried or immersed metallic structure.

Ground potential rise (GPR): The maximum electrical potential that a substation grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. This voltage, GPR, is equal to the maximum grid current times the grid resistance.

NOTE—Under normal conditions, the grounded electrical equipment operates at near zero ground potential. That is, the potential of a grounded neutral conductor is nearly identical to the potential of remote earth. During a ground fault the portion of fault current that is conducted by a substation grounding grid into the earth causes the rise of the grid potential with respect to remote earth.

Holiday: A hole, break or other discontinuity in the coating on a pipeline, which causes the pipe surface to be exposed.

IR error: This is the error contained within the pipeline potential recorded at ground level remote from the actual pipe surface. This error is caused by the flow of cathodic protection currents and the resistance of the soil and coating.

Impressed current: The current supplied by a rectifier or other direct-current source, (specifically excluding a galvanic anode), to a protected structure in order to attain the necessary cathodic protection.

Inductive coupling the coupling between two electric circuits through inductances linked by a common changing magnetic field.

Insulated flange: A flanged joint between adjacent lengths of pipe in which the nuts and bolts are electrically insulated from one or both of the flanges by the use of insulating sleeves and the jointing gasket is non-conducting, so that there is an electrical discontinuity in the pipeline at that point.

Insulated joint: A manufactured joint or coupling between two lengths of pipe, inserted in order to provide electrical discontinuity between them.

Instant 'OFF' potential: The structure to electrolyte potential that is obtained immediately after the disconnection of the structure under CP from the CP current source. This is sometimes referred to as the polarised potential and is the true pipe to soil potential excluding any voltage created by current flowing through the soil and pipeline coating.

Interaction test: A test to determine the severity of corrosion interaction between two buried or immersed structures.

Interference phenomenon resulting from conductive, capacitive, inductive coupling between systems, and which can cause malfunction, dangerous voltages, damage, etc.

interference voltage - voltage caused on the interfered system by the conductive, inductive and capacitive coupling with the nearby interfering system between a given point and the earth or across an insulating joint.

Natural potential: See free corrosion potential.

Permanent reference electrode: A permanently buried or immersed reference electrode designed for long life and installed close to the structure to enable the structure potential to be measured.

Polarisation: An effect of electrolysis, which occurs, on either the anode or the cathode of a cell when gas or chemical products form on the electrode. The polarisation effect is to increase the circuit resistance of the cell thus reducing the current for a given voltage.

Polarised potential: The potential between a reference electrode and the pipeline, which exists immediately after an interruption of the CP current, (i.e. instant off potential).

Reference electrode: A device used to compare potentials at various locations by providing a standard for potential measurement. Electrodes may be made of zinc, copper in a saturated copper sulphate solution or silver and silver chloride in a chloride ion solution of known concentration.

Sacrificial anode: An anode that relies on a natural potential difference as a source of power. The 'driving voltage' can be found from the electrochemical series. Metals generally used as galvanic

Stray current: Incidental current picked up by a structure from adjoining foreign sources.

Soil resistivity: specific resistance of a soil to carry electric current. Soil resistivity is expressed in Ω m (earlier in Ω cm). The lower the soil resistivity, the easier it is for electric current to flow through the soil. Fine-grained soils with water holding capacity (clay, silt, peat etc.) usually have low resistivity, whilst coarse grained and water draining soils (sand, gravel, till etc.) usually have a high resistivity. The water and salt content of the soil have a large influence on the resistivity. A high water and a high salt content results in a lower resistivity. Road de-icing salt, which is drained through the soil, lowers the soil resistivity.

Spread resistance: ohmic resistance through a coating defect to earth or from the exposed metallic surface of a coupon to earth.

Note: This is the resistance which controls the d.c. or a.c. current through a coating defect or an exposed metallic surface of a coupon for a given d.c. or a.c. voltage.

Sulphate-reducing bacteria (SRB): These act as depolarisation agents in the soil around the structure and are harmful to the cathodic protection effect. They achieve this by reducing sulphate ions to sulphide and consuming the hydrogen of the polarisation film. They occur in anaerobic soil conditions and can result in relatively high rates of corrosion.

Telluric effect: A natural phenomena caused by solar activity deforming the earth's magnetic field causing low frequency current to flow in the general mass of earth. Telluric currents can result in stray current interference on long pipelines.

Touch voltage: The potential difference between the ground potential rise (GPR) and the surface potential at the point where a person is standing while at the same time having a hand in contact with a grounded structure.

Appendix C: Typical Questionnaire Pipeline Operator to Power Line Operator

AC INTERFERENCE QUESTIONNAIRE

Item	Question	Response
1.0	Power System Operator and Contact details	
2.0	Operating Voltage and tolerance in voltage and frequency	
3.0	Power circuit designation and name	
4.0	Earthing impedance at substation	
5.0	Tower construction details	
6.0	Tower span	
7.0	Number of phases	
8.0	Number of circuits	
9.0	Average Height of Conductor 1 from ground	
10.0	Average Horizontal Distance of Conductor 1 from ground	
11.0	Phase angle of conductor 1	
12.0	Average Height of Conductor 2 from ground	
13.0	Average Horizontal Distance of Conductor 2 from ground	
14.0	Phase angle of conductor 2	
15.0	Average Height of Conductor 3 from ground	
16.0	Average Horizontal Distance of Conductor 3 from ground	
17.0	Phase angle of conductor 3	
18.0	Conductor resistance	
19.0	Earth/shield wire resistance and conductor size	
20.0	Average tower footing resistance	

Item	Question	Response
21.0	Fault clearance time msec	
22.0	Fault level substation	
23.0	Fault current pylons	
24.0	Peak Loading (Amps)	
25.0	Normal Operating Load (Amps)	
26.0	Designed Rated Load (Amps)	
27.0	Emergency Loading (Amps)	
28.0	Emergency Loading Time (Amps)	
29.0	Operating Power Loading MVA	
30.0	Transposition Locations	
31.0	Phase arrangement on Pylons	

Appendix D: Typical Questionnaire Power Line Operator to Pipeline Operator

Pipeline Questionnaire

Item	Question	Pipeline Operator Response
1.0	Pipeline operator, address and contact details	
2.0	Pipeline systems within vicinity of new power lines	
3.0	Pipeline system details, pressure, wall thickness, diameter	
4.0	steel grade	
5.0	Pipeline length	
6.0	Pipeline route drawings	
7.0	CP system type sacrificial or impressed current	
8.0	Pipeline CP system drawings and test post locations	
9.0	CP system TR unit and groundbed location's	
10.0	CP system operating levels	
11.0	Coating thickness and type	
12.0	Pipeline Engineering Line Diagram	
13.0	Pipeline design code	
14.0	Are there any inter pipeline bonds	
15.0	Is any a.c mitigation system already installed	
16.0	Coating impedance to be considered for AC system design purposes Ohms m^2	
17.0	Isolation joint locations and whether buried or above ground	
18.0	Details of any surge protection already installed	
19.0	Details of any existing ILI features	

Item	Question	Pipeline Operator Response
20.0	Safe working requirements for work in vicinity of pipeline	
21.0	Details of any over the line surveys	
22.0	Details of any existing a.c interference on pipelines or power lines in vicinity	
23.0	Soil resistivity data	
24.0	CP test post design and method of cable to pipe connection	
25.0	Pipeline burial depth	

Appendix E: AC Corrosion on Pipelines UK Experience

Although it had been demonstrated in the 1960's under laboratory conditions that a.c. current can cause corrosion of cathodically protected pipelines, it was not recognized until comparatively recently that a.c. corrosion of cathodically protected pipelines can and does occur. The phenomenon of "alternating current corrosion," or "A.C. corrosion," has been investigated in detail since the observation of the first corrosion damage in Europe by induced a.c. currents, which resulted in a.c. corrosion on cathodically protected pipelines in 1988 [29, 30].

Ellis [31] reported the first incident of a.c. corrosion in the UK during a UKOPA conference in 1999. The HSE in the UK then advised all pipeline operators to be aware of the a.c. corrosion risk and then take steps to identify pipeline systems at risk of a.c. interference and take appropriate action. The latter guidance it is considered still applies today.

A.C. corrosion occurs at small coating holidays on well coated pipelines where the pipeline suffers from induced a.c. voltages. It can occur on pipelines that have effective levels of CP.

Pipelines which parallel overhead or buried power lines and also a.c. traction systems can have an a.c. voltage and current induced on them. The a.c. current flow in the power line conductors produces an alternating magnetic field and that can result in low frequency induction on buried pipelines.

Thus, an a.c. voltage and current can be induced in an adjacent structure within that magnetic field and a current may flow in that structure. The magnitude of the induced voltage depends on a number of factors including:

Configuration of the power line and pipeline e.g. length of parallelism and separation from the pipeline

- Separation distance between each of the phase conductors and the pipeline
- Current load on the power line
- Power circuit operating voltage
- Imbalance between phases
- Impedance of the pipeline coating.
- Soil resistivity

In general terms the greater the current load on the power line, the longer the parallelism, the closer the proximity, the better the coating quality on the pipeline, the more likely it is that significant a.c. voltages and current will be induced on a pipeline.

For many years, the general view in the corrosion industry has been that alternating current causes approximately 1% of the corrosion of the equivalent direct current.

A.C. corrosion can result in relatively high rates of corrosion on cathodically protected pipelines, such that even if the protection criteria to ensure immunity from corrosion detailed in BS EN 12954 are obtained on the pipeline, if the pipeline is exposed to an a.c. corrosion risk, then corrosion may still occur and often at rates considerably in excess of the free corrosion rate for steel in soil.

The high coating quality pipelines namely fusion bonded epoxy (FBE) and 3-layer polyethylene and polypropylene pipelines are particularly susceptible to a.c. corrosion. However, a.c. corrosion can also occur on the older coal tar enamel coated pipelines. The a.c. current densities recorded on the pipeline were in the region of 40 to 160 $Am^{-2.}$ The pipeline was installed in 1992 and a 40% wall thickness loss was identified in a pig run carried out in 1996.

The pipeline diameter was 10" and the product transported was dense phase ethylene. The pipeline design pressure was 99.3 bar. The pipe minimum wall thickness was 5.65 mm for standard wall pipe and a 40% loss of wall had occurred over a 7-year period at one location, which would equate to corrosion rate of 0.57 mm per year.

A subsequent pig run was carried out in 1999 and additional defects were identified, where the metal loss was 30% of wall thickness, which would equate to a corrosion rate of 0.24 mm per year.

The soil resistivities were low at the defect location with Ellis quoting values of 1,500 Ohm cm (15 Ohm m) at 1m depth and 500 to 800-Ohm cm, (5 to 8 Ohm m) at 1.5 metres. At the time the pig runs took place on the pipeline there was no a.c. mitigation system installed.

An a.c. mitigation system on the pipeline was installed after 1999 to discharge the a.c. current induced on the pipeline to earth. Following the 1999 incident another incident of a.c. corrosion was reported on a gas pipeline in the UK in 2002. The pipeline was a 16" diameter 75 barg high pressure natural gas pipeline to a power station.

Movely [32] discussed the pipeline and another a.c. corrosion investigation on a 16" diameter pipeline to a gas fired power station in the UK from a regulatory authority' perspective. The gas fired power station incident occurred in 2002 and there was a total of 93 external corrosion defects identified on an in-line inspection conducted in December 2002 following pipeline installation In September to December 1999.

Lydon [33] provided additional details on the a.c. corrosion investigation on the pipeline to the gas fired power station described in Movely's paper. Lydon advised that the pig run data showed that the defects were concentrated within two areas. The first set of 33 defects were concentrated within an environmentally sensitive low soil resistivity location referred to as an SSSI. The second set of 60 external metal loss defects was concentrated in a clay soil that ran parallel to a main road. These defects were concentrated between chainage 4371m to 5891m.

The following corrosion rates were reported and are given on Table 10

Defect Locations	Corrosion Rate mm per year		
	Mean Rate	Minimum Rate	Maximum Rate
SSSI Area	0.7	0.17	1.2
Salt Marsh Area	0.41	0.17	0.81

Table 10 A.C. corrosion rates 16" gas pipeline UK 2002

The resistivity at the SSSI site was very low, in the region of 1-ohm m, whilst that in the salt marsh area was between 8 to 10 ohm m.

The pipeline system was also subjected to d.c. stray current interference for a short period of time shortly after construction and it is known that where both a.c. and d.c. interference occur on a pipeline system then this can result in higher rates of a.c. corrosion. Nielsen [13] has published data for corrosion rates on pipelines susceptible to both a.c. and d.c. interference and higher rates of corrosion are experienced.

There have since the latter incidents been other reported a.c. corrosion incidents in the UK on both FBE and coal tar enamel coated gas pipelines.

Lydon reported the highest a.c. corrosion rate in the UK on an intermediate pressure gas pipeline in the South of England in 2006, where through wall corrosion occurred and the corrosion rate was in the region of 2.42mm per year see Figure 11 A.C. corrosion defect current density 450 to 600 Am^{-2} 8" intermediate pressure < 7bar gas main.

Figure 11 A.C. corrosion defect current density 450 to 600 Am^{-2} 8" intermediate pressure < 7bar gas main

The increased corrosion rates on a pipeline without an a.c. interference mitigation system due to a.c. interference will vary from about 0.1 to 2.5mm per year based upon UK experience.

A.C. corrosion in the UK is not just restricted to FBE or 3LPE coating systems. Eyre [34] in 2015 reported two case studies involving a.c. corrosion on coal tar enamel coated pipelines.

One case resulted in through wall corrosion on a 7.7mm thick 8" diameter coal tar enamel coated aviation fuel line.

The 2006 ILI had indicated a metal loss of 49% at a defect location and through wall failure occurred in 2015 this equated to a corrosion rate of 0.42mm per year.

The a.c. voltage and soil resistivity were low at the defect site. The voltage was in the region of 1.75V rms and the soil resistivity 10 Ohm m. The leak site was at a CP drain point not too far from where a 400kV power line deviated from the pipeline route. The average a.c. current density at the defect location was quoted as $43Am^{-2}$.

The second case Eyre reported was on a refined product pipeline where 49% loss of wall thickness occurred. The a.c. voltage varied between 1 to 6.0V at the defect site and the soil resistivity was very low at 1 ohm m. A.C. current densities in the region of 5 to 380 Am^{-2} were recorded at the defect location, which was where the pipeline route crossed a 400kV overhead power line at an acute angle.

The corrosion rate from a.c. interference will be dependent upon a number of factors. These are most notably, the a.c. current density, the soil resistivity and soil composition, the pipeline coating system, the pipeline route relationship to the power line system, particularly the separation between the pipeline and the power line, the pipeline crossing angle and the current loading on the pipeline system.

A.C. interference primarily occurs on pipelines that are routed in parallel with power lines operating at voltages of 66kV and above.

Generally, the higher the a.c. discharge current density the higher the corrosion rate. However, the corrosion rate at different current densities does vary and is dependent upon a number of different factors.

The a.c. corrosion defects identified on the both pipelines discussed in Movely's paper are understood to have been arrested by the installation of an a.c. corrosion mitigation system. However, for pipelines considered to be at risk of a.c. interference it is prudent to have an increased ILI frequency until it can be confirmed that the a.c. corrosion process has been arrested by any mitigation system.

In the UK with corrosion rates up to 2.5mm per year being reported on pipelines without any mitigation system it is essential that the a.c. corrosion risk is controlled to ensure pipeline integrity and safety.

Whilst FBE pipelines are more susceptible to a.c. corrosion it can also occur on coal tar enamel and two-layer polyethylene coatings.

In the case of modern pipeline coating systems, the coating quality is high, and the high coating impedance means that the a.c. current flow through the coating is relatively low, with most current concentrating on small defects in the coating system. Thus, it is the small surface area coating defects on a pipeline that are the high-risk locations for a.c. corrosion.

The UK experience has shown that where the soil resistivity is very low, a.c discharge current densities can be very high and there is a high risk of a.c. corrosion at relatively low a.c. voltages.

Soil resistivity and composition plays an important role in the a.c. corrosion rates and likely risks.