AC induced corrosion on onshore pipelines, 
a case history.

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Introduction

AC induced corrosion is a significant threat to integrity of buried pipelines, due to its very high localized corrosion rate. It can and has resulted in metal loss of more than 1 mm per year.

Shell UK constructed a new 412 km long 10 ins diameter high pressure ethylene pipeline in 1992. In 1996 a 100km section of the pipeline was intelligently pigged which resulted in the identification of significant metal loss features. Initial investigations following an intelligent pig investigation assigned the cause of significant pipeline metal loss to microbial action. Improvements to the levels of cathodic protection were made to ensure adequate protection. A further intelligent pig investigation in 1999 confirmed the reoccurrence of similar defects.

This paper describes the history of the investigations and how the phenomena was ultimately attributed to the effects of induced AC. Discussion and background research findings is given on probable causes of AC induced corrosion, how it can be predicted and how the effects can be mitigated against.

Background

The NW ethylene pipeline (NWeP) is a 412 km, 10 ins diameter pipeline running from Grangemouth on the river Forth in Scotland, through Southern Scotland and North West England to Stanlow on the river Mersey. The pipeline provides ethylene feedstock to the Shell Chemicals and Basell businesses in the NW of England. Ethylene originates predominantly from the Shell/Exxon Fife ethylene plant in Scotland though the UK ethylene pipeline system allows ethylene to also be sourced from BP at Grangemouth and Huntsman in Wilton.
**The pipeline specific characteristics are as follows:**

Pipeline diameter: 250mm  
Pipeline length: 412km  
Product: Dense phase ethylene.  
Product properties:  
- Winter 3 deg.C density 363.6 kg/m³  
- Summer 13 deg.C density 298.1 Kg/m³  
Design pressure: 99.3 bar g  
Normal operating pressure: 90 to 60 bar g  
Material properties and wall thickness  
- Design factor 0.3: API 5L X60 11.91 mm  
- Design factor 0.72: API 5L X52 5.65 mm  
Burial depth: minimum 0.9m  
Minimum normal temp: -10 deg.C (blow down)  
Maximum normal temp: 24 deg.C (at pump outlet)  

**Coating**

The pipe is coated with fusion-bonded epoxy applied at the Ramco Carlson Hartlepool plant. The coating was applied generally in accordance with Shell Expro Standard ES/014 External Coating of Carbon Steel Line pipe and Bends by Epoxy Powder.

The coating was applied by electrostatic spraying of the epoxy powder onto a preheated, white metal, blast cleaned surface. The surface of the pipe was pre-treated with a chromatic conversion coating to improve its resistance to cathodic dis-bonding. The dry film thickness was 475 ± 75 microns.

**Cathodic protection**

The pipeline is cathodically protected by an impressed current system.

There are 15 cathodic protection stations along the pipeline route. Ten of these stations are located at block valves and their current output is monitored by the SCADA system. The pipe-to-soil potential is also monitored by the SCADA system at all block valves and at Grangemouth and Stanlow.

Test posts are located at a nominal 1 km spacing along the pipeline route.

Prior to commissioning of the impressed current system, the pipeline was protected by a temporary sacrificial cathodic protection system. This comprised magnesium anodes located in areas where soil resistivities were less than 3,000 ohm cm. These were disconnected when the impressed current system was energised.

The impressed current system was designed to cope with a 95% reduction in coating performance from an initial 100,000 ohm/m² to 5,000 ohm/m². In addition, there is a 100% over capacity in the cathodic protection station sizing.

The following criterion was set for the operation of the system. "Off" pipe-to-soil potentials or "Off" coupon potentials on the NWeP should be maintained more negative than -0.95V with respect to a Cu/CuSO₄ reference electrode. "On" pipe-to-soil potentials should not be more negative than -1.5V to reduce the risk of cathodic disbondment of the coating.

The Cathodic Protection Scheme was commissioned in 1992.
CP Stations at BV19 and BV21 provide protection for the Longton area in Electrical Section 7, (BV19 to BV22 a distance of 50.6 km). Current output from CPS12 at BV19 has been steady at some 0.4A. At BV21, current output has varied more, with values recorded from 0.4 to 0.7A up to February 1997 and from then values of between 1.0 to 1.2A. The current density required to protect Electrical Section 7 is somewhat higher than the other. This is due in part to the river Ribble Crossing taking 340 mA after installation.

Interaction with other pipelines

In the Longton area, NWeP runs close to, parallels and crosses both the North West Multiple Route (NWMR) pipelines (8 inch Ethylene & 12 inch Oil) and the 42 inch Lupton-Bretherton Transco pipeline.

This section of the Transco pipeline is protected by four cathodic protection stations located between Capenwray (Lancaster) and Longton, ground bed outputs varying from 0.5-2.0 amperes.

The Huntsman Ethylene pipeline is protected by three cathodic protection stations located near Woodplumpton, Longton (shared with Transco) and Ring 0 Bells. Current output from these stations is around 1.0 ampere each.

Overhead power transmission lines

The National Grid, Penwortham, Kirkby 400 kV power line parallels NWeP from just south of the Ribble Crossing to the River Douglas, some 12 km. The Manweb, Penwortham, Kirkby 132 kV parallelism runs for 4km in the same area.

Detailed map and picture of the Longton area.
Intelligent pig investigation in 1996

In 1996, an intelligent pig survey of NWeP was undertaken from BV1 9 to Stanlow by Rosen Engineering GMbH.

This indicated several areas of metal loss concentrated in the Longton area. Field verification exposed defects with a metal loss of up to 40%. What was particularly noticeable in these investigations was the apparent high levels of hydrogen sulphide in the decaying peat.

Excavations in other areas of this section of the pipeline was limited to revealing external mill defects with the pipeline coating remaining intact.

Further investigation work carried out in 1997 to determine the cause of the

Visual inspection of coating
Soil analysis
Interference tests with Transco and ICI (now Huntsman).
Coupon data
CIP Surveys over defect areas
DCVG surveys over defect areas

The conclusions of the various investigations were that the metal loss should be attributed to microbiological induced corrosion associated with the activity of sulphate reducing bacteria.

Metal loss features were assessed against ANSI/ASME B31.G and none required any structural repair

The coating defects were repaired using a proprietary repair system and the cathodic protection station output were increased to give 'off' potential of -140OmV at the drain points with respect to the Cu/CuSO4 reference in accordance with guidelines at the time, to mitigate the microbiological effects of sulphate reducing bacteria.

Intelligent pig investigation in 1999

In 1999 a further intelligent pig survey was undertaken in sections 1 and 2 of the pipeline from Grangemouth to Carlisle and the intelligent pig survey repeated in section 4 BV19 (Garstang) to Stanlow. Additional areas of metal loss were indicated in the Longton Area and field verification confirmed new defects of in excess of 30% wall loss (circa 2 mm) had occurred since the last investigation in 96-97.
The corrosion products have been removed from the defect

The underside of the coating and products removed from the pipeline embedded in the soil

Coating and corrosion products removed from the soil.
Further investigative work was carried out. This work comprised:

**Soil analysis**

Soils were, as in 1996-97 analyzed in the laboratory. SRB on-site tests undertaken in the latter part of 1999 indicated some SRB activity, but only after some 7 - 10 days incubation, on less than 30% of samples. During the excavation work, the smell of H₂S was present. Soil samples taken and analysed indicated neutral to slightly acidic soils and unexceptional levels of salts, (chlorides, carbonates and sulphates). This cast doubts on the corrosion being caused by microbiological effects. Soil resistivities of some 1500 ohm cm were recorded at 1 m depth and 500-800 ohm cm at 2m depth.

**Coating assessment**

When the pipe was exposed in 1997 and 1999 the 'problem defects' appeared to initiate at areas of black staining on the coating and possibly at pin holes in the FBE coating, although it is not clear at what stage the pin holes developed. The coating was extremely well bonded to the pipe in the areas surrounding the defects. Removal was only possible with a sharp knife. DSC tests on several retained samples of the FBE coating were within the accepted limits.

**AC measurements**

AC potentials measured on the pipeline range from 4 to 18 volts and dc potentials were steady. The 2 sites were close to the Northern and Southern end of the 132 kV parallelism. At the north the levels varied from 4-8 volts and at the Southern end 4-18 volts. Of significance was the daily variation in AC levels particularly the high levels in the middle of the night.

**Measurement coupons**

Coupons were installed in the area in 1997. Coupons installed at the extremities of the parallelism indicated that good levels of polarisation were being achieved. Alternating currents recorded at all four coupons in 1999 were
high, with 100 - 400 mA measured. This equates to an ac current density of some 40 - 160 Am⁻².

**DCVG measurements**
The survey in August 1999 picked up some of the minor coating breakdown subsequently exposed during the excavations. DCVG defect indications were sized as very small, and generally the DCVG tests accurately suggested a lack of protection at all significant defects. However some smaller defects found in the excavation may have been too small for the DCVG equipment to detect, given the extremely low area of coating damage involved and the nature of the defect (with the coating broken but not necessarily clearly exposing pipeline steel).

**CIPS measurements**
CIP surveys carried out indicated good levels of protection. No indications of a localized loss of protection were indicated.

**Interference tests**
Tests undertaken with Huntsman and Transco indicated negligible levels of interference. DCVG surveys undertaken with the Transco ground bed switching, did not detect any interference from the Transco ground bed, located less than two kilometres upstream.

**Conclusion of AC corrosion**
It was concluded that:
The corrosion was not due to microbial action, the Ph values were high and there was no iron sulphide.
There was no interaction with the other pipelines
The FBE coating was in excellent condition.
There were high current densities in the region of 40-160A/m².
The corrosion at the Longton site could not be attributed to any other phenomena and the evidence strongly pointed to the effects of AC induced corrosion. Further field verification and investigation into AC corrosion cause and effects were undertaken.
Further field verification work at other sites along the pipeline.

Following the initial findings at Longton further detailed analysis of the intelligent pig results and AC current density measurements were made for other sections of the pipeline. In particular metal loss features with a small plan area and in areas of low soil resistivity were prioritised.

Similar corrosion, but largely isolated features were found in 2 areas further North on the pipeline. Winmarleigh just south of BV1 9 near Garstang and road crossing RDX71 between BV9 and 10 north of Gretna in Scotland. Very similar characteristics were found along the pipeline route, i.e. low soil resistivity and a relatively high current density.

At the more Northerly feature, RDX71 after identifying the feature and repairing the coating there was a delay of about 8 months before the mitigation could be installed. At the time of installing the mitigation a further coating survey revealed that a new metal loss feature of about 1 mm depth had occurred in the intervening period, indicating a corrosion rate in excess of 1 mm per year.

At Winmarleigh access difficulties and restrictions prevented field verification of the 1999 metal loss features for about 2 years, i.e. until 2001. The metal loss features measured in the field correlated very well with the metal loss predicted in the 99 intelligent pig investigation. This indicates that there had been insignificant further metal loss in the period 99 to 2001 after the initial metal loss had been identified.
Discussion on the AC effects.
The intelligent pig survey in 1999, confirmed that the corrosion was ongoing in Longton.

pH measurements were carried out on the exposed pipe at the sites of the corrosion pits in Autumn of 1999.

Of the ten tests carried out, three were neutral and seven were very alkaline at 11-12. This indicates the cathodic reaction $2\text{H}_2\text{O}+\text{O}_2+e^- \rightarrow 4\text{OH}^-$ was occurring and that the cathodic protection system was working.

The high pH also indicates that SRB activity was not the cause of the corrosion as SRB's require a near neutral environment to proliferate.

The X-Ray diffraction analysis carried out on the corrosion deposits did not determine the presence of iron sulphides, which would indicate the corrosion, is not being driven microbially.

The ac potentials measured over a period of 7 days at the defect areas were in the range 4 - 18V for most of the time and varied considerably over the 24 hour clock.

This is below the 15V criteria set by NACE above which mitigation measures are considered necessary. The level of 15V however, is set for safety reasons and has nothing to do with corrosion.

The ac current densities measured in the coupons installed in the defect areas at 40 - 160 $\text{A/m}^2$ are well above the presently accepted threshold at which ac corrosion is likely to occur.

The most probable cause of the corrosion was concluded to be AC induced.

Causes of AC corrosion

It has been demonstrated in the 1960's that under laboratory conditions ac can cause corrosion of cathodically protected steel.

It was not recognized until comparatively recently that ac corrosion of cathodically protected pipelines can and does occur. Most of the detailed research work on this subject originated in Germany where the problem was recognised in the late 1980's early 1990's. AC corrosion occurs at small coating holidays on well coated pipelines when the pipeline suffers from induced ac voltages.

Pipelines which parallel overhead power can have ac voltage induced on them. The ac current flow in the power line conductors produce an alternating magnetic field. An ac potential can be induced in an adjacent structure within that magnetic field and a current flow may occur in that structure. The magnitude of this induced potential depends on many factors including:

The configuration of the power line and pipeline e.g. length of parallelism and relative changes in direction.

The current load on the powerline.

The balance between the phases.

The dielectric strength of the pipeline coating.

The soil resistivity.

In general terms the greater the power load on the overhead line, the longer
the parallelism, the closer the proximity, the better the coating quality on the
pipeline, the more likely it is that significant ac potentials will be induced on the
pipeline.

For many years, the general view on the corrosion industry has been that
alternating current causes 1% of the corrosion of the equivalent direct current.
The results of a research project in Germany has shown that:

Corrosion is unlikely at ac densities < 20 A/m2.
Corrosion rates > 0.1 mm/yr can occur at ac densities > 100 A/m2.
For ac densities ≥ 20 A/m2 the protective potential criteria usually used for
cathodic protection does not apply.

Ignoring the polarisation resistivities, the ac density at a coating defect with a
diameter d is given by the following equation:

\[ I = \frac{8 \times V}{\rho \pi d} \]

Where \( V \) is the ac voltage on the pipeline,
\( \rho \) is the soil resistivity
\( I \) is the effective ac current density.

Tests on coupons have shown that the corrosion rate reaches a maximum for
coating holidays of 1 cm². Although the current densities would be greater for
smaller defects, below a certain size it is considered that the corrosion product
blocks the passage of current.

The research has also shown that the soil properties also have an effect on
the rate of ac corrosion. Anaerobic soil or soils containing carbonate and
bicarbonate ions tend to have higher ac corrosion rates whilst neutral media
containing significant amounts of salts are considerably less aggressive.

The level of ac potential on the pipeline does not reflect whether corrosion is
occurring, nor does it reflect the rate of corrosion if it is occurring. The 15V
level of ac potential set in NACE and Canadian Standards above which
mitigation action is required, is set at this level for safety, and has no bearing
on the corrosion aspects.

It is reasonable to assume that if the soil resistivity is low enough, high ac
densities can be achieved at low ac potentials.

If equation 1. is used then it is apparent that a 100 A/M² current density can be
produced at a 1 cm² holiday in 1,000 ohm cm soil with an ac potential as low
as 4.4V. The frequency of the ac is reported to have little effect on the
corrosion rate unless very low frequencies are used.

Some research suggests an incubation period of 30 to 120 days for current
densities of 100 and 50 A/M² respectively, after which corrosion rates
increased. Other studies have shown that the corrosion rate decreases with
time regardless of the ac density.

The actual mechanism of ac corrosion is not fully understood. The ac
potentials may have an effect on the dc polarisation of the pipe. Alternative
theories centre on the irreversible nature of the corrosion
reaction: \( 2Fe > Fe^{2+} + 2e^- \) which will occur during the anodic half cycle.

The characteristics of ac corrosion on pipelines can be summarised as follows:
The corrosion causes a hemispherical pit
High pH conditions may be found in the pit
A hard mound of corrosion product is produced above the pit
The area may be well protected by the CP system.

Cases of AC corrosion have been identified in a number of European
Countries, Germany, Switzerland, France and Belgium and in North
America in Canada. Shell were the first company to identify the problem in
the UK

Prediction of AC corrosion
The mechanisms of AC corrosion are not fully understood but prediction and
means of mitigation are.
In the section of NWeP from Carlisle to Garstang the running of an intelligent
pig had not proved to be technically feasible. The intelligent pig identifies the
consequences of corrosion and it was recognised that the threats could be
identified.
To experience AC corrosion a number of factors need to be present and these
can be determined.

- A pipeline with a coating that has a high dielectric strength, i.e. a good
  insulator such as FBE or 3 layer polyethylene.
- A means of inducing AC onto the pipeline and relative changes in direction
  of pipeline and power lines. i.e. overhead power lines.
- A soil of low resistivity providing a good route to earth for the current.
- A high current density measured through a small coupon ideally 1 cm2.
- A coating defect and a means of determining it.

By undertaking analysis and measurement of the pipeline route sections were
determined in which AC induced corrosion would be most likely to occur. In
these sections the direct current voltage gradient (DCVG) technique was used
to determine areas of coating breakdown. Field digs were undertaken to verify
the pipeline condition. No serious metal loss features were found though
indications of the early stages of AC corrosion were evident in a number of
sites. The majority of the pipeline length was not considered to be susceptible
to the AC effect.

Technological advances allowed the pipeline to be pigged in the summer of
2001. The detailed results and field verification are currently under review.
The initial findings however have concluded that metal loss features have only
been identified in areas where AC would have been predicted and where
mitigation is already planned or in place. Detailed correlation of the DCVG
work and intelligent pig work continues.

Mitigation of AC corrosion
Research suggests that the rate of ac corrosion decreases with time. However,
this cannot be relied upon.

The work carried out so far at the defect locations has included the removal of
the existing coating and the application of a new coating based on a
recommended repair system.

This will prevent further corrosion at the defect locations provided the coating
remains intact. However despite the 100% holiday detection prior to backfill, it is considered that coating holidays may be still be present or could occur in the future. The pipeline could therefore experience ac corrosion in the future should current density levels be high. Continuous monitoring is necessary.

Whilst the mechanism of ac corrosion is not fully understood the mitigation measures are. The pipeline needs to be earthed using a system compatible with the cathodic protection system such that the ac current densities are reduced below 20 A/m². The risk of ac corrosion occurring should be reduced to a tolerable level.

Mitigation Measures have been implemented by the installation of earthing systems. This earthing comprises 150m length of zinc ribbon installed parallel to the pipe 2.5m from the pipe centre line.

Calculations show that the installation of a 150m length of ribbon should reduce current density levels of 35-500 A/m² to between 2-32 A/m² These calculations do however ignore the effect the earthing will have on the ac potential. The earthing reduces the ac potential and so measured current densities are much lower, well below the 20A/m² threshold criteria above which ac corrosion is considered too occur. A target ceiling of 15A/m² was used for the design basis for the mitigation systems. Monitoring is being and will continue to be carried out over an extended period using data loggers to verify on going levels of current density. Where possible 1cm² coupons have been installed to allow ongoing monitoring.

AC current density monitoring will form an ongoing part of the pipeline integrity management system.

Conclusions.
AC induced corrosion is a potentially serious phenomena and could lead to failure of a buried pipeline.

AC corrosion can however be predicted and the following are considered to be the main ingredients.

A source of induced AC
A coating of high dielectric strength
A soil of low resistivity or good earth.
Small coating defects.
A high current density.

Monitoring an data logging of induced AC and current densities running to earth should form an integral part of pipeline integrity management

Mitigation in areas of high susceptibility can be achieved by installation of a preferential earthing system.

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