This document was downloaded from the Penspen Integrity Virtual Library

For further information, contact Penspen Integrity:

Penspen Integrity
Units 7-8
St. Peter's Wharf
Newcastle upon Tyne
NE6 1TZ
United Kingdom

Telephone: +44 (0)191 238 2200
Fax: +44 (0)191 275 9786
Email: integrity.ncl@penspen.com
Website: www.penspenintegrity.com

Repairing Internal Corrosion Defects in Pipelines

- A Case Study

Roland Palmer-Jones
Andrew Palmer and Associates, UK
Email Roland.Palmer-Jones@apancl.co.uk
Dominic Paisley
BP Exploration, Alaska
Email paisledm@bp.com

1. Abstract

This paper discusses the requirements for the safe long term repair of internal corrosion in oil pipelines, and presents a case study where, following assessment of the corrosion type, a suitable repair was selected and the long term performance demonstrated. The following issues are addressed:

- Internal corrosion mechanisms, locations and forms.
- Preventing continuing corrosion.
- Methods for measuring defect location and extent.
- Repair, rehabilitation or replacement; which is appropriate?
- Through wall defects; what are the implications for the repair?
- An appraisal of different repair methods suitable for internal defects, and how they work.
- Long term or temporary repair; can long term performance be assured?

2. Introduction

Andrew Palmer and Associates (APA) have recently assisted BP in the rehabilitation of two oil flowlines with internal weld corrosion with 'permanent' repairs i.e. repairs suitable to remain in place for the remainder of the pipelines' design lives.

The corrosion was predicted to continue, albeit at a reduced level, with the possibility of defects growing through the pipe wall within a number of years, and therefore the method chosen needed to contain the process fluids, even after prolonged exposure to those fluids. There is a wide variety of repair methods, including: cutting out the defective section, welding a snug fitting shell over the defective area, or fitting a leak clamp. Different methods work in different ways and they may or may not be suitable for repairing internal corrosion, depending on the depth, length, orientation and possible future growth of the defect. If these factors can be quantified then a suitable repair system can be selected and appropriate analysis carried out to demonstrate that it will be fit for purpose.

This paper presents a structured system for determining the feasibility of repair, selecting an appropriate repair and demonstrating the suitability of that repair.

3. Internal Corrosion

Internal corrosion in oil and gas pipelines is primarily caused by the presence of water together with acid gases (carbon dioxide or hydrogen sulphide), or sulphate reducing bacteria. It can be divided into three broad categories:

- Sweet Corrosion
- Sour Corrosion
- Sulphate Reducing Bacteria

In this section of the paper we will briefly look at what may cause each of these categories of corrosion, and discuss the shape and location of the resulting corrosion features.

3.1 Sweet Corrosion

Sweet corrosion can take place when there is carbon dioxide and water in the pipeline. The carbon dioxide dissolves in the water to form carbonic acid, which reacts with the pipeline steel causing corrosion damage. For bare steel in contact with carbonic acid the corrosion rate will be very high. However, corrosion products form an iron carbonate layer on the metal surface and this reduces the rate of corrosion. The system temperature, pressure, concentration of carbon dioxide and the flow rate will also affect the rate of corrosion. The flow rate has an effect because if the flow is sufficiently high that it is fully turbulent there will be no separation out of water, and the inner surface of the pipe will be continuously re-coated with oil making corrosion unlikely.

3.1.1 Mesa Corrosion

Mesa corrosion in the base (6 o'clock position) of the pipeline is characteristic of sweet corrosion. Well developed mesa corrosion has the appearance of a long groove in the bottom of the pipe.

The corrosion is concentrated in the base of the pipe as this is where the water (and carbonic acid) will tend to collect as it separates out. The characteristic 'mesa' is formed by the corrosion continuing at a more rapid rate at locations where the 'protective' iron carbonate layer is disturbed. Typically, downstream of an original pipe wall or weld defect, there will be increased local turbulence in the flow. This turbulence can disturb the 'protective' layer and result in a locally increased corrosion rate. As the corrosion defect forms there will be increased turbulence at the downstream edge, leading to relatively rapid growth along the pipeline.

Material variations, such as weld spatter, can also prevent the formation of a stable iron carbonate layer. This will result in pitting or general corrosion, depending on the extent of the material variation.

3.1.2 Inhibitors

Corrosion inhibitors are widely used to reduce the rate of sweet corrosion, and they can be very effective. The basic concept is that the inhibitor forms a film on the metal surface, preventing any water or other corrosive element coming into contact with the metal. Inhibitor efficiency is affected by the flow rate and by the state of the pipe surface. Low flow rates will reduce inhibitor efficiency, very high flow rates may prevent the formation of the protective film. Where the pipe surface is covered in produced solids or other debris, the inhibitor may be absorbed by this debris and therefore not form the required protective film.

3.2 Sour Corrosion

Sour corrosion will take place when the fluids in the pipeline include water and hydrogen sulphide. The presence of hydrogen sulphide can have a number of different effects:

- Metal loss corrosion due to the presence of hydrogen sulphide is a similar mechanism to carbon dioxide corrosion in that hydrogen sulphide dissolves in the water associated with oil production, forming a weak acid. In this case, the corrosion product is iron sulphide and, like iron carbonate, it can be semi-protective, reducing the rate of further corrosion. The iron sulphide film tends to break down locally, allowing small pits to form.

- Sulphide Stress Cracking (SSC) may take place when a susceptible metal is subject to a sour environment and level of stress (the stress may be residual or applied). The cracking is thought to be caused by the embrittlement of the metal by hydrogen. SSC is found to attack higher strength materials (actual tensile strength of 550MPa or higher). Hence, provided the line pipe is correctly specified, it is often associated with weld heat affected zones and cold worked sections, which tend to be stronger than the standard line pipe.

- Hydrogen Induced Cracking (HIC) is most likely to affect susceptible steels where an iron sulphide film has developed and hydrogen is present. Corrosion processes produce hydrogen. HIC takes the form of blisters in the pipe wall around manganese sulphide inclusions left in the steel during manufacture (it is very difficult to remove all the manganese sulphide from the steel). Hence, HIC does not tend to be found at particular locations, such as weldments.

3.3 Sulphate-Reducing Bacteria (SRB)

The corrosion process(es) associated with microbial metabolism are poorly understood. In oil producing facilities, a wide range of bacterial types may be present, classified as general anaerobic bacteria and sulphate reducing bacteria. It is the latter that are generally associated with corrosion and their acidic bi-products of metabolism are thought to be the primary cause of microbial induced corrosion.

4. Inspection

Inspection vehicles known as 'SMART PIGS' are widely used to inspect the condition of pipelines. These vehicles can identify changes in the wall thickness of the pipeline. Any changes in wall thickness identified can be classified based on the calibration of the inspection vehicle on pipe sections with known features. The accuracy of these inspection vehicles is steadily improving. However there are limitations in the measurement of feature size (length and depth), feature circumferential position within the pipeline and feature location along the pipeline. Figures quoted by smart pig supplier for the feature sizing and location accuracy of metal loss features are given in Table 1.

Dimension	**Stated Accuracy**
Detection - Minimum Depth, Length > 3t	0.2t
Detection - Minimum Depth, Length < 3t	0.4t
Depth	+/- 0.15t
Length (Feature Length>3t)	+/- 20mm
Length (Feature Length<3t)	+/- 10mm
Minimum metal loss area	(7mm) x (7mm) or (0.4 x 0.4t)
Location - axial	+/- 8 inches or 0.2m from reference weld
Position - circumferential	+/-5%

Note: t = thickness of the pipe being inspected.

Table 1 Resolution Specifications for a Smart Pig (12" to 56")[1]

The accuracy may be affected by the pipeline design; for example where there is an internal lining. In some cases the accuracy of the internal inspection may not be sufficient to reliably locate a feature, or give the dimensions accurately enough for assessing the significance of a feature. In these cases other forms of inspection such as external ultra-sonic examination, or surface laser scanning may be used. These other methods will give a much more accurate measurement than the internal inspection, but they are impractical for examining the whole line.

5. Repair, Rehabilitation or Replacement Strategy

Pipeline rehabilitation projects are not solely driven by the choice of repair or rehabilitation method. They are driven by economics, urgency and engineering considerations:

(i) COST - for example, the cost of the repair clamp for a damaged offshore pipeline is negligible compared to the cost of the vessel that has to be hired to install the repair.

(ii) URGENCY - a catastrophic failure (effecting people or environment) has such a devastating effect on public relations, etc., that the least of a company's worries is the type of repair/rehabilitation. Cost to public image, lost revenue and clean up costs are key considerations.

(iii) ENGINEERING - the 'engineering' associated with any work on a pipeline may be the crucial consideration. For example, an offshore line that has lost its weight coating, and is floating, or an onshore line that is to be lifted out of a trench and recoated live, will require extensive engineering work.

5.1 Repair and Rehabilitation - Approach

Pipeline rehabilitation should be part of the whole life costing of a pipeline, and it should be treated as a pipeline engineering/construction/overhaul (i.e. engineering, retrieval/trenching, section rehabilitation, backfill, inspection, etc.), requiring a wide engineering approach. This approach will always ensure a cost beneficial solution. For example, knowledge of new construction prices can show that rehabilitation is increasingly attractive as the pipeline diameter increases.

Pipe size	**% of new construction**
6-14-inch	70-130%
16-24-inch	50-90%
28-48-inch	25-50%

Table 2 Costs for rehabilitating pipelines compared to new builds (landlines)[2].

Smaller diameter pipe is cheap to buy, hence material costs of a new line are low. Certainly, pipeline diameters below 16 inch may be cheaper to replace rather than rehabilitate[3]. Therefore, rehabilitation becomes attractive as the diameter increases, but this is a general statement, and will not apply in every case, Figure 1. In this case we can see that a strategy incorporating regular inspection is the best financial solution. Clearly a cost model must be used to determine the best rehabilitation.

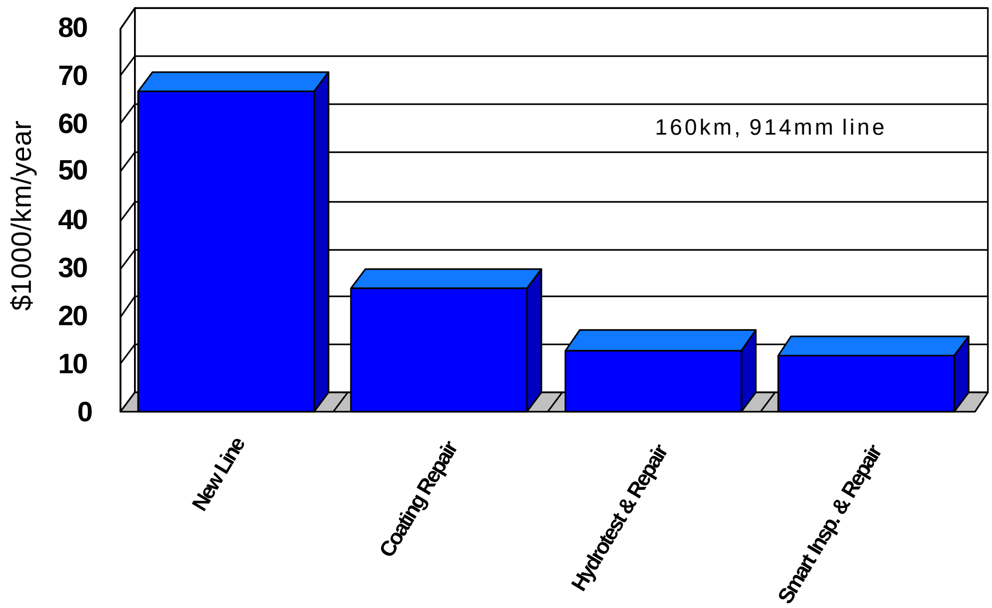


Figure 1 Differing costs for differing rehabilitation solutions (landlines)[4].

5.2 Rehabilitation of Pipelines with Internal Corrosion

To develop an efficient strategy for the rehabilitation of a pipeline with internal corrosion the following factors should be considered:

(i) The type (corrosion mechanism), extent and severity of the corrosion defects present.

(ii) The required life, and the benefits that achieving it would bring (i.e. revenue earned).

(iii) The remaining life of the pipeline based on the available data.

(iv) The benefits of gathering additional data.

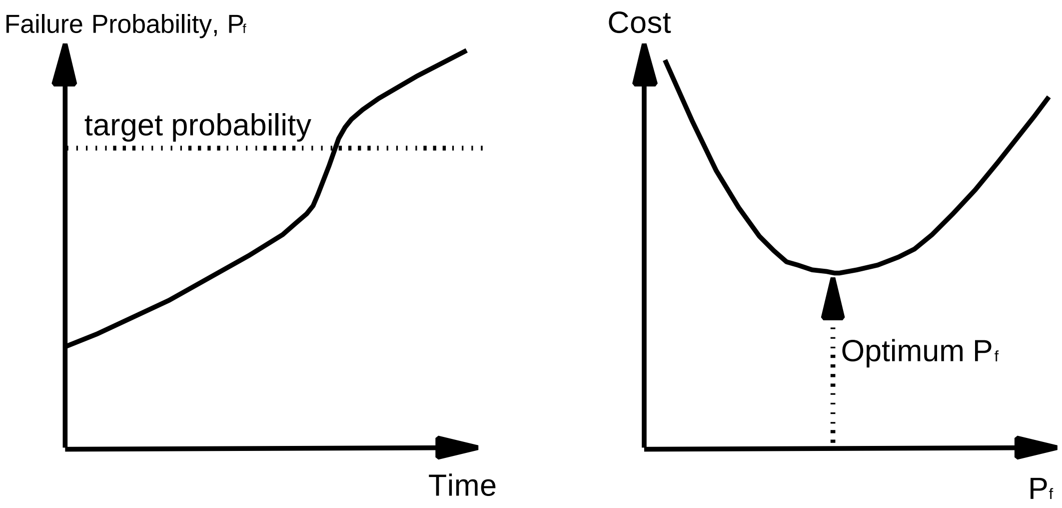
(v) The practicality and cost of the control of future corrosion (by flow control or inhibition for example).

(vi) The effectiveness and costs of the proposed remedial methods (e.g. lining, replacement). Including the potential costs of failure.

(vii) The cost of future inspection.

(viii) Regulatory requirements

Having reviewed and costed the various factors these can used in a cost model to identify the optimum solution. Figure 1 has shown how various options will incur widely varying costs. Figure 2 shows a simple cost model, based on pipeline failure probability. These models are a key element of the overall strategy.



$$MinimumCost = \sum C_{inspection}(P_f) + \sum C_{repair\,/\,rehab}(P_f) + \int C_{failure}(P_f)$$

Figure 2. Example of cost model for repair and rehabilitation.

Figure 2 shows an operator setting a target failure probability, and ensuring that a rehabilitation programme does not take him/her past this target level. The total cost of rehabilitation in this model is taken as the sum of inspection and repair/rehabilitation costs (discrete values), and the cost of failure (variable). Iterations of the model will obtain the optimum cost solution.

6. Repair Options

Pipeline repair/rehabilitation systems can be considered in four broad categories:

(i) Systems that will limit the future growth of corrosion features. Internal linings and biocides are examples of this type of system.

(ii) Repairs that are designed to restore the strength of the pipe containing a part wall defect, such as a gouge that might be caused by external interference. The Clockspring™ composite wrap is a good example of such a system[6].

(iii) Repairs that are designed to contain the transported fluid in the event of the defect failing. The Plidco™ leak clamp is an example of such a system[7].

(iv) Repairs that will restore the strength of the pipe and contain the transported fluid in the event of the defect failing. The 'type B' welded shell is an example of this type of repair[5].

Internal corrosion can be addressed using systems from all categories. However, if future corrosion is expected then the possibility of a through wall defect must be considered, and the repair system must be able to contain the resulting leak or rupture. The selection of an appropriate system is therefore a complex process

7. Repair Options for Internal Corrosion

There are several types of repair and rehabilitation methods that may be applicable to internal corrosion defects, including:

(i) Full Circumferential (Welded) Sleeves,

(ii) Welded Patches,

(iii) Composite Reinforcement,

(iv) Mechanical Clamps,

(v) Pipe Section or Pipeline Replacement,

(vi) Internal Liners,

In this section the applicability of each method to the repair of internal corrosion is considered and some advantages and disadvantages are identified.

7.1 Fully Circumferential Welded Sleeves

Fully circumferential welded sleeves are widely used for the repair of pipelines. They comprise two shells, which are assembled around the pipe and then welded together. There are several variations:

- Type A - no welding to pipe (reinforcement only)
- Type B - welded to pipe (pressure containment)
- Stand-off Shell (pressure containment)

- Epoxy Filled Sleeve (used on type A, can use on B, see Figure 3)

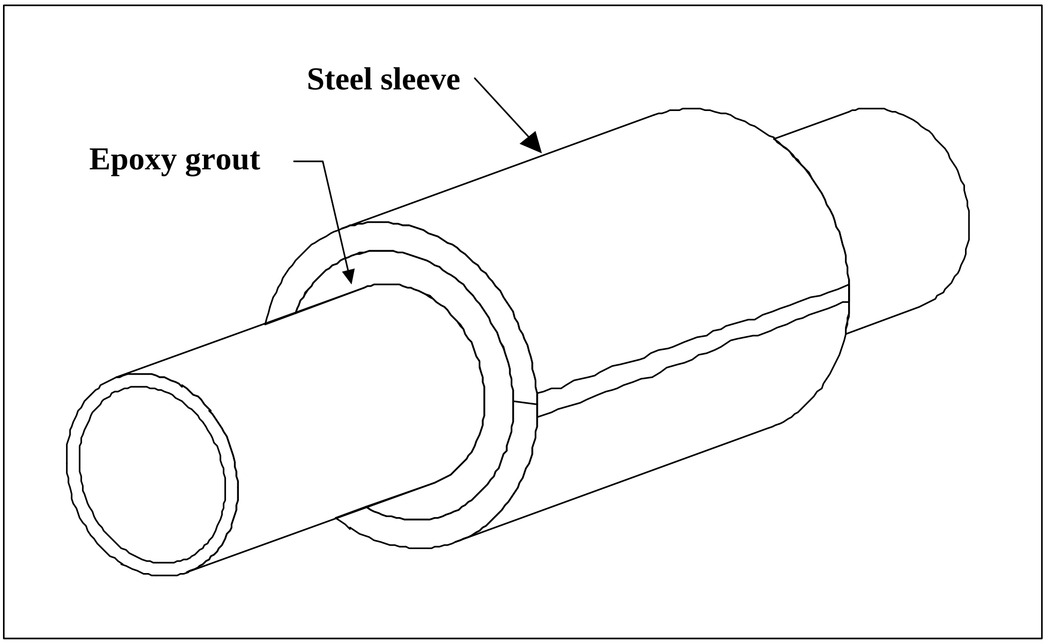


Figure 3 Epoxy Filled Sleeve Repair

7.1.1 Type A Sleeve

Advantages	**Disadvantages**
Proven in service	Will not contain a leak, therefore not suitable for active internal corrosion
Permanent	Requires welding, which is a significant disadvantage for subsea use.
Simple	Difficult to inspect welds
Contractors are familiar with the application of welded sleeves, as they have been used in the pipeline industry for many years.	Will provide some defect restraint, but will not prevent defect failure.
	No axial strength

7.1.2 Type B Sleeve

Advantages	Disadvantages
Will contain a leak	Requires welding, which is a significant disadvantage for subsea use.
Proven in service	Difficult to inspect welds
Permanent	Fillet weld at sleeve end is often a source of defects.
Simple	Requires welding to the pipeline, which can be difficult where the pipe wall is thin, or the product flow cools the wall rapidly.
Contractors are familiar with the application of welded sleeves, as they have been used in the pipeline industry for many years.	In the event of a leak the fluid may corrode the sleeve material.
Limited axial strength	Will provide some defect restraint, but will not prevent defect failure.

7.1.3 Stand Off Shell

Advantages	Disadvantages
Can be fitted to bends etc.	Requires welding, which is a significant disadvantage for subsea use.
Will contain a leak	Difficult to inspect welds
Permanent	Fillet weld at sleeve end is often a source of defects.
Simple	Requires welding to the pipeline, which can be difficult where the pipe wall is thin, or the product flow cools the wall rapidly.
Limited axial strength	Very large number of welds and complex fabrication process.
	Will provide some defect restraint, but will not prevent defect failure.
	In the event of a leak the fluid may corrode the sleeve material.

7.1.4 Epoxy Filled Sleeve

Advantages	**Disadvantages**
Restores the original strength of the pipeline.	Limited experience on through wall (leaking) defects.
Proven in service	Not originally designed for through wall (leaking) defects.
Permanent	Sub sea application not proven
Simple	
Will support defect and prevent defect failure through load transfer and (primarily) restraint	
Sleeves can be either welded together or have flanges. The latter eliminates welding	
Can support axial loads.	

7.2 Welded Patches

A pre-formed steel plate is welded to the pipeline over the defect.

Advantages	**Disadvantages**
Will contain a leak	May not prevent the failure of the defect.
Permanent	Requires welding, which is a significant disadvantage for subsea use.
Simple	Difficult to inspect welds.
	Fillet weld around patch is often a source of defects.
	Requires welding to the pipeline, which can be difficult where the pipe wall is thin, or the product flow cools the wall rapidly.
	In the event of a leak the fluid may corrode the sleeve material.
	Will provide some defect restraint, but will not prevent defect failure.

	Is only practical for small areas.

7.3 Composite Reinforcement

A composite material, such as GRP, is tightly wrapped around the pipeline to improve the strength and prevent the bursting of the defect.

Advantages	**Disadvantages**
Strengthens the pipe in the area of the defect.	Limited experience on through wall (leaking) defects.
Proven in service, and now widely accepted	Most systems will not provide axial strength
Permanent	
Simple	
By using multiple repairs relatively long lengths can be strengthened.	

7.4 Mechanical clamps

Two half shells with a built in rubber seal are bolted together around the pipe. The shells can be welded together and then to the pipeline to create a permanent repair. Mechanical clamps are often used for emergency repairs

Advantages	**Disadvantages**
Will contain a leak	May not prevent the failure of the defect.
May be made permanent	Generally temporary as rubber seals will degrade over time.
Proven in service	Must be welded to the pipe to make a permanent repair.
Relatively quick and simple to install	Heavy and difficult to handle.
Some types can provide axial strength	In the event of a leak the fluid may corrode the clamp material.
	Will only repair a relatively limited length.

7.5 Pipeline or Pipe Section Replacement

Where defects are very severe and widespread it may be necessary to replace a part or the entire pipeline.

Advantages	**Disadvantages**
Permanent	Expensive
Pipe may be re-designed to ensure problem does not re-occur, e.g. a change in the type of steel to one that is not susceptible to a particular corrosion mechanism.	Takes a long time and the pipeline has to be taken out of service for some period, unless the tie-in can be hot tapped, further increasing expense.
Can be used for extensive damage.	

7.6 Internal liners

The pipeline may be fitted with an internal liner that will prevent further corrosion. There are a variety of methods available to do this:

- Cured in-place - a thin reinforced textile liner, fixed by adhesive
- Modified slip lining - polyethylene liner compressed & expanded
- U-Process - polyethylene deformed to U shape, rolled in & expanded
- High Density Polyethylene - installation method not established

Advantages	**Disadvantages**
Permanent	Pipeline must be taken out of service and cleaned.
May not need to excavate.	Can only be installed in short lengths (up to 800m).
Possible to repair relatively extensive corrosion.	Ends of the liner have to be sealed/joined to next section.
	Concerns over use on sour service pipelines.
	May interfere with internal inspection.

8. Case Study - BP Wytch Farm

8.1 Introduction

In 1997 BP discovered internal corrosion on two flowlines (10 and 12" diameter) at the Wytch Farm site in Southern England. The corrosion was caused by CO_2 in the transported fluid (sweet corrosion). The severity of the corrosion was related to the flow conditions, with the incidence of corrosion pits being higher in areas of high flow rate. In addition, higher mean corrosion rates were identified at the pipeline girth welds, believed to be a result of localised turbulence[8].

8.2 Inspection

Corrosion in the lines was originally identified by internal inspection. However, this inspection did not identify problems at girth welds. The girth weld corrosion was discovered following two failures. It seems that the internal inspection had been unable to identify small (10mm) diameter corrosion pits located on the pipeline girth welds. More accurate external inspection techniques, including gamma radiography and ultrasonic inspection, were applied to approximately 30% of the girth welds. This data was used to improve the interpretation of the original internal inspection data, and categorise all the girth welds by severity of corrosion.

8.3 Repair Selection

A large number of welds were identified as having more than 60% wall loss due to internal corrosion[8]. However, at each location the most severe corrosion was confined to a relatively small area. The corrosion was predicted to continue, albeit at a reduced level, with the possibility of defects growing through the pipe wall within a number of years.

BP required a repair system that would prevent leakage over the remaining life of the pipeline (26 years). They also required a system that it would be possible to deploy at relatively short notice.

The epoxy filled sleeve system using welded shells developed by BG (formerly British Gas) was selected[1] (see below).

8.4 Performance

The epoxy filled shell repair has been in use since 1983[9]. However, there is a limited track record in the use of this repair method as a permanent repair for through wall internal corrosion defects as it was originally designed for the repair of defects such as dents, gouges, external corrosion and cracking in dry gas lines operating at ambient temperatures. Therefore, the qualification procedure had to demonstrate its suitability for the repair of internal corrosion defects, where the possibility existed that those defects may penetrate the pipe wall in the future, and the operating temperature is approximately 58°C.

[1] This repair technology is now marketed by Pipeline Integrity International (PII), UK.

There are four major issues to consider with respect to the long-term integrity of epoxy filled shell repairs for the proposed application:

i. Basic grout properties.
ii. Tolerance of the grout to contact with the pipeline product.
iii. Cracking of the grout, combined with poor bonding to the shell.
iv. Progressive failure of the bond due to cyclic loading.

The following sections cover these issues, and also presents the results of a detailed finite element stress analysis to model the failure of the epoxy bond.

8.4.1 Basic Grout Properties

The basic grout properties are critical regardless of the defect growing through wall. The key factor that may affect the properties is the temperature.

i. *Tensile Strength and Modulus*: Correct selection of the epoxy grout used to fill the pipeline/shell annulus is a critical factor in ensuring the long term integrity of this type of repair. It is necessary to have a material that will cure in the correct manner at the specified installation temperature and also maintain its properties (particularly tensile/bond strength and elastic modulus) within acceptable limits in the long term over the specified operating temperature range. Confidential test data supplied by the epoxy filled shell repair supplier, PII, and the grout manufacturer, indicated that the tensile strength and modulus of the grout chosen for these particular repairs are satisfactory up to an operating temperature of 75°C. Therefore the grout will be satisfactory for the repairs at Wytch Farm where the operating temperature is approximately 58°C.

ii. *Bond Strength:*

a) Bond performance at elevated temperature: No data were available relating to bond strength (shear strength and tensile strength) at the proposed operating temperature of 58°C. However, confidential test data on the bond strength at room temperature showed it to be similar to the grout tensile strength; this may also be the case at elevated temperature.

b) Effect of installation at differential temperature: some data from one test in which the pipe was kept at 6°C and the surroundings at 25°C with high humidity [9] was available. This was, however, an external corrosion defect repair and as such the bond strength was not critical to the performance. For an external corrosion defect the important parameter is grout stiffness; the grout prevents any bulging of the defect that may lead to failure. It is not required to act as a sealant.

The author is not aware of any other relevant experimental work undertaken to investigate the effects of a temperature difference between the pipe and the shell at installation. Intuitively the bond between pipe and grout will be good but the bond between grout and shell may be compromised by differential curing (the grout nearest the pipe cures first).

c) Effect of surface condition at installation: the bond strength is critically dependent on the surface condition at installation. Consequently the repair installation guidelines require dry surfaces. Other contamination such as grease or oxidation on the surface will also have a detrimental effect on the bond strength. Hence the installation guidelines also require thorough grit blasting and advise that the time between blasting and grout injection is minimised. The repairs at Wytch Farm were all carried out in dry summer conditions after grit blasting and both of the lines were warm. Therefore, the surface condition is expected to be good.

ii. *Creep Behaviour:* No data were available in relation to creep behaviour of the grout used in the Wytch Farm repairs. It is understood, however, that creep of the grouts used in lower temperature applications (5 - 30°C) would not be expected to degrade the effectiveness of the repair [9]. Therefore, it could be expected that the creep of grouts formulated for higher temperatures would also not degrade the effectiveness of the repair.

8.4.2 Tolerance to Contact with the Pipeline Product

The main concern here is whether exposure of the grout to the pipeline product will lead to significant degradation of the grout properties. One of the advantages in selecting an epoxy-based grout is the excellent chemical resistance claimed for epoxy-based materials in manufacturers' literature. Tests into the effect of H_2S contaminated crude oil on the grout materials used by PII, for high temperature repairs show that the UTS and modulus remain above normally acceptable limits[10]. The conclusion from these tests is that immersion in oil or water has no detrimental effect on either tensile strength or tensile modulus, in the medium[2] term.

8.4.3 Cracking of the Grout Combined With Poor Bonding to the Shell

i. *Potential Failure Mechanism.* The bonds between grout and pipe, and grout and shell, provide the seal in the event of a through wall defect. For the best possible bond all surfaces must be clean, dry and warm when the grout is injected. When installing repair shells it is possible to grit blast the pipe after the shells have been assembled and welded together, thus ensuring the minimum possible degradation of the surface. However, it is not possible to grit blast the inside of the shell rigorously after welding. Hence the grout to shell interface is the most vulnerable to contamination and poor bonding. The area of the shell seam weld will be the worst affected because the process of welding increases the probability of local surface oxidation.

If the grout were to crack, due either to a weak spot or cyclic loading, and the grout to shell bond was poor, then a leak path may be formed. The probability of a poorly-bonded region of the shell aligning with a through wall defect (and any potential cracking) may be minimised by ensuring that the shell seam weld is positioned such that it is not aligned with the defect. This was done for the repairs installed on the flowlines at Wytch Farm.

[2] Medium term in this context is defined as three months.

ii. *Effect of repair during shutdown*. The 10” Wytch Farm pipeline was repaired whilst shutdown. The heating and resultant axial expansion force developed on start up could have a beneficial effect. It will cause a compressive axial load in the pipewall (and therefore the grout) and prevent any cyclic axial tensile loading, thus reducing the probability of a circumferential crack developing in the grout in the event of a circumferentially orientated through wall defect. There may still be cyclic hoop loads that could cause axial cracking of the grout in the event of an axially orientated through wall defect.

The difference in thermal expansion co-efficient between the grout and the steel may have a detrimental effect on the grout to pipe bond or the grout to shell bond, and will certainly introduce significant changes to the internal stresses of the grout on heating. No data is available to quantify what these effects may be.

iii. *Effect of a small annulus and the flanged shell design.* In the design of the shell repair it is desirable to minimise the grout annulus, as this will reduce shrinkage effects (the grout volume change on curing) thus reducing stress on the bonds and minimising the possibility of poor adhesion.

The use of the flanged shell system, which minimises the time lapse between grit blasting and grouting, minimises the time available for surface degradation.

One flanged repair was installed at Wytch Farm, but the rest were welded type repairs. As the conditions during installation were warm and dry, and hence degradation of the internal surfaces of the shells would not cause concern over the bonding.

8.4.4 Progressive Failure of the Bond

A further concern in respect of defects growing through the pipe wall after repair is the possibility of pressurised product leading to disbonding/cracking and progressive failure along the grout/pipeline interface[3] (see Figure 4). There is no long-term evidence of exposure of epoxy repairs to this type of loading.

[3] Similar behaviour is possible at the grout/shell interface if the product can gain access.

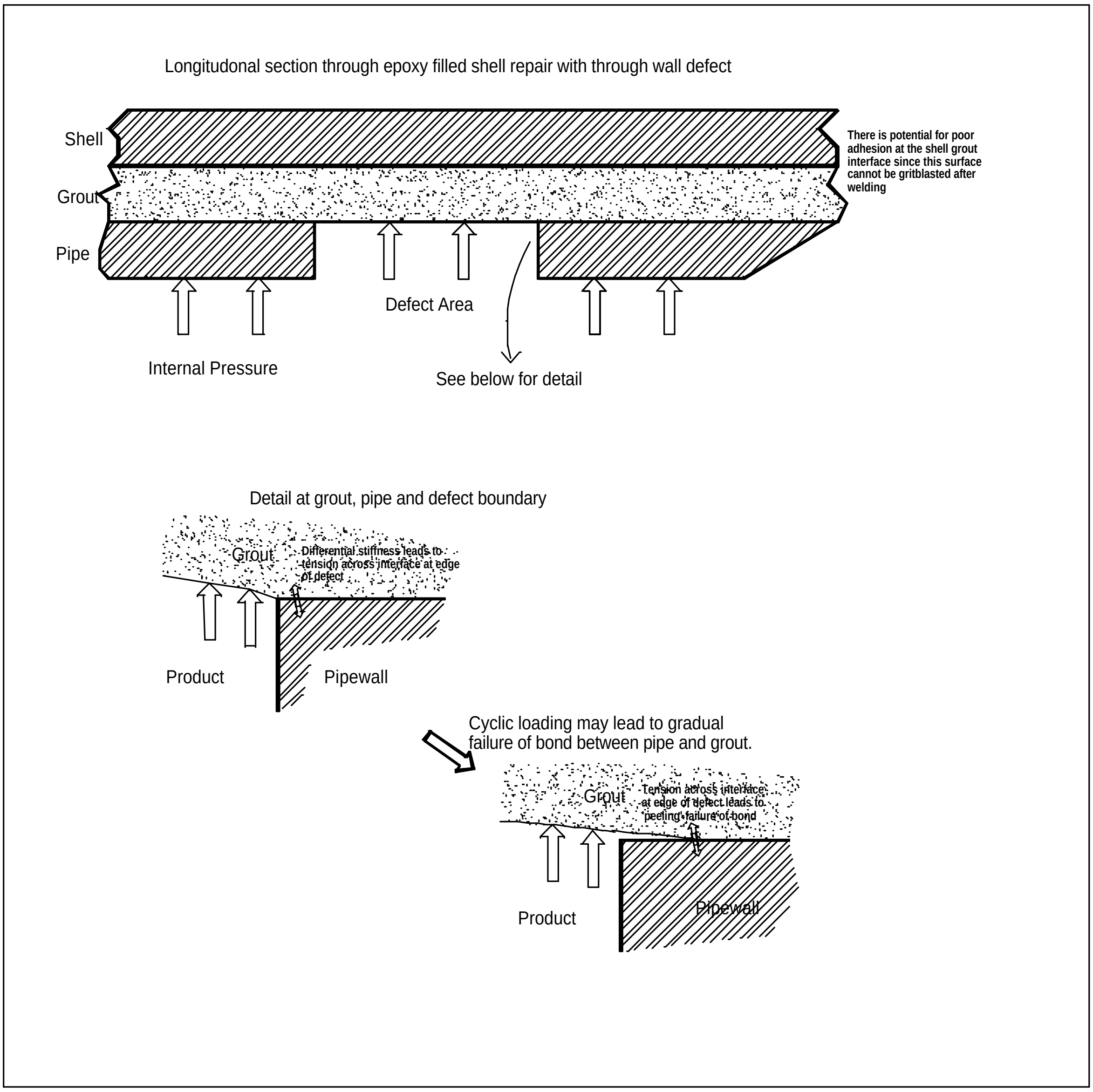


Figure 4 Possible Failure Mode in the Event of Circumferentially-Orientated Through wall Corrosion

To investigate the possibility of progressive failure of the bond a detailed finite element study was carried out. The key to assessing the potential for disbonding or cracking along the grout/shell interface is the stress generated in the grout. The non-linear finite element (FE) analysis code ANSYS 5.4[11] was used for the analysis of the pipeline repair.

8.4.5 FE Model - Geometry and Elements

The FE models were constructed from the relevant pipe and shell dimensions. Axi-symmetric and 3D models were generated. A quarter model was generated for the 3D cases, taking advantage of symmetry. Axial symmetry was considered for both axi-symmetric and 3D models. Regular rectangular elements were used in both models. High order elements were used in the models created. These are less sensitive to mesh density and aspect ratio and are better suited to the analyses than low order elements. For the axi-symmetric cases, ANSYS element type PLANE82 was used, while SOLID95 elements were used in the 3D models. Although mesh density effects are not very pronounced for high order elements, some mesh density trials were performed, mainly using the axi-symmetric case, to ensure that adequate element sizes were used.

8.4.6 FE Model - Pipe and Shell Material

An elastic-plastic material model with linear kinematic hardening was used for the pipe and shell. The basic material data are presented in Table 3 and Table 4.

Property	Value
Elastic Modulus	207 GPa
Density	7850kg/m^3
Coefficient of expansion	1.16 x 10^{-5} per ^{0}C
Poisson's ratio	0.3
SMYS	289MPa
UTS	413MPa

Table 3: Material Data for API 5L - X42 Steel (Shell).

Property	Value
Elastic Modulus	207 GPa
Density	7850kg/m^3
Coefficient of expansion	1.16 x 10^{-5} per ^{0}C
Poisson's ratio	0.3
SMYS	241MPa
UTS	413MPa

Table 4: Material Data for API 5L - Grade B Steel (Pipe).

8.4.7 FE Model - Epoxy Grout Material

The grout was treated as an elastic-perfectly plastic material, at the operating temperature, based on the findings of uni-axial tests[12]. It has been assumed that the steel to grout bond is stronger than the grout itself. This assumption is supported by the results of a tensile pull off test[13]. The grout may behave in a brittle manner (rather than plastic), particularly at lower temperatures.

For the purposes of this analysis, where the expected mode of failure is cracking of the grout creating a leak path, two failure criteria have been considered:

- Local failure of the grout. The average (mean) through thickness stress in the grout reaches its ultimate strength over a small area in the vicinity of the defect. This will cause localised cracks.

- General failure of the grout. The stress in the grout reaches its ultimate strength fully through the thickness, and spreads away from the defect. This will cause localised cracking that is likely to spread as load transfers away from the failed region.

8.4.8 Model Validation

An experiment on a repair, in which the stresses on the outer surface of the shell have been measured, was used to validate the method, and for the mesh density trials[14].

8.4.9 Analysis Results

14 cases were analysed, and the results are given in Table 5 for the 10" pipeline and Table 6 for the 12" pipeline.

Three pressures were considered:

i. 35 bar, to simulate the pipeline design pressure.

ii. 52.5 bar, to simulate a hydrotest (1.5 x design pressure).

iii. 100 bar, to simulate a very high pressure.

Four pipeline defect sizes were considered:

i. 75 mm long by 28.6 mm wide, to simulate the largest predicted individual defect. The predicted length has been increased from 40 mm to 75 mm for conservatism.

ii. 100 mm long by 57.2 mm wide, to simulate the coalescence of two adjacent defects. The predicted length has been increased for conservatism.

iii. 250 mm long by 71.5 mm wide, to simulate the coalescence of three adjacent defects. The predicted length has been increased for conservatism

iv. 75mm long by fully circumferential, to simulate complete separation of the pipeline.

The defect sizes are based on worst case predictions of future corrosion made by BP[15].

Case No.	Pipeline Pressure Bar	Through Wall Defect Size [1]		Defect Description	FE Analysis Result	
		Length (mm)	Width (mm)		Grout stress, % of UTS	Comment
1	35	75	28.6	Width equivalent to a single defect.	56	No through thickness grout cracking.
2	35	100	57.2	Width equivalent to 2 defects combined.	71	No through thickness grout cracking.
3	35	250	71.5	Width equivalent to 3 defects combined.	83	No through thickness grout cracking.
4	35	75	Circ.	Fully circumferential defect.	100	**Localised through thickness grout cracking.**
5	52.5	250	71.5	Width equivalent to 3 defects combined.	95	No through thickness grout cracking.
6	100	250	71.5	Width equivalent to 3 defects combined.	100	**General through thickness grout cracking.**
7	100	75	Circ.	Fully circumferential defect.	100	**General through thickness grout cracking.**

Table 5: FE Analyses Results for Wytch Farm 10” Pipeline Repairs

1. The defect lengths analysed are longer than those predicted. This will ensure a conservative assessment of maximum acceptable defect width.

Analysis No.	Pipeline Pressure Bar	Defect Size [1]		Description	Analysis Result	
		Length (mm)	Width (mm)		Grout stress, % of UTS	Comment
8	35	75	28.6	Width equivalent to a single defect.	38	No through thickness grout cracking.
9	35	100	57.2	Width equivalent to 2 defects combined.	61	No through thickness grout cracking.
10	35	250	71.5	Width equivalent to 3 defects combined.	74	No through thickness grout cracking.
11	35	75	Circ.	Fully circumferential defect.	90	No through thickness grout cracking.
12	52.5	250	71.5	Width equivalent to 3 defects combined.	97	No through thickness grout cracking.
13	100	250	71.5	Width equivalent to 3 defects combined.	100	**Localised through thickness grout cracking.**
14	100	75	Circ.	Fully circumferential defect.	100	**General through thickness grout cracking.**

Table 6: FE Analyses Results for Wytch Farm 12" Pipeline Repairs

1. The defect lengths analysed are longer than those predicted. This will ensure a conservative assessment of maximum acceptable defect width.

8.5 Discussion of FE Results

There are six different factors that have been considered in order to assess the likelihood of failure of the repairs installed on the 10" and 12" pipelines at Wytch Farm.

8.5.1 Effect of Defect Size

The larger the defect, the higher the through thickness peak stress generated in the grout. This is shown in analysis cases 1 - 4 (Table 5), and cases 8 - 11 (Table 6). At the design pressure of 35 bar, only the fully circumferential defect in the 10" pipe (case 4) resulted in the through thickness stress in the grout reaching the ultimate tensile strength of the grout material.

For the 10” pipeline, at the design pressure, a defect larger than 71.5mm wide by 250mm long is required before the grout may crack. The largest individual defect predicted is 23.4mm wide by 31.6mm long[15]. At least 4 adjacent defects would have to coalesce to create a defect with a width of more than 71.5mm.

For the 12” pipeline, at the design pressure, the grout is not predicted to crack even with a fully circumferential defect.

8.5.2 Effect of Load

Increased internal pressure leads to higher stress in the grout. This is shown in cases 3, 5 and 6 (Table 5), and cases 10, 12 and 13 (Table 6). At the design pressure the grout will not be stressed to failure. At a typical hydrotest pressure of 1.5 x the design pressure the grout is not predicted to crack. The maximums of the average through thickness stresses in the grout, predicted at the hydrotest pressure, are very close to the ultimate strength of the grout. At pressures in excess of the hydrotest pressure the stress in the grout will reach the ultimate strength of the grout and it may crack. Cases 6, 7 and 13 (in Table 5 and Table 6) show the stress resulting from an extreme pressure loading of 100 bar (with the stress in the pipeline approaching yield).

The current operating pressure of both pipelines is 22 bar, the Maximum Allowable Operating Pressure is 30 bar and, the design pressure is 35 bar. An automatic trip system shuts down the wells if the pressure in the pipelines reaches 27 bar. Therefore, the internal pressure should not exceed the design pressure. The only time that the pressure may exceed the design pressure is if the operating regime is changed, or if the pipeline is hydrotested.

8.5.3 Effect of Cyclic Loads

There are two sources of cyclic loads that may affect these pipelines:

- Shutdowns - Planned or un-planned shutdowns will cause large stress cycles in the grout. Fewer than 5 shutdowns (or system trips) per year are predicted, giving a maximum of 125 cycles before the pipeline is decommissioned. Full scale tests on epoxy filled shell repairs at similar cyclic stress levels to those predicted for the Wytch Farm system, have shown high tolerance to cyclic loads[10]. After 1000 cycles the grout exhibited limited cracking behind a through wall defect, and no leakage was reported.

- Slug passage - The pressure cycles that might be caused by slugs passing along the pipeline will be very small (< 1bar). This pressure cycle is negligible in comparison with shutdowns, and is not expected to cause fatigue damage.

8.5.4 Effect of Installation Conditions

The 10” pipe was repaired while shut down and the 12” pipe was repaired while operational. In the FE analysis, the internal pressure at repair was modelled accordingly. A comparison of the 10” and 12” results (Table 5 against Table 6) show that installation condition has no significant effect on the stresses in the repair. Possible grout shrinkage and the effects of the different curing conditions of the grout were not taken into account in the analyses. This is because all of the repairs are understood to have been installed in warm dry conditions. Hence, differences in curing are expected to be minimal.

9. Conclusions

i. Selecting an appropriate system requires a clear understanding of the nature and extent of the corrosion, knowledge of the way in which a particular repair system works, and reliable predictions of the future operation of the pipeline.

ii. The epoxy-filled shell repair can be used for the long term repair of internally corroded pipelines.

iii. Information provided by the supplier, and detailed finite element stress analyses were required to prove the repair's integrity.

10. Acknowledgements

This work was conducted by Andrew Palmers and Associates, on behalf of BP. The authors would like to thank colleagues in both their organisations for contributing to this work.

11. References

1. http://www.piigroup.com/Tools/maghr.html

2. Trefanenko, B. et al, '*Risk Assessment: an Integrity Management Tool*', Pipeline Risk Assessment, Rehabilitation and Repair Conference, Houston, 1992.

3. Ketszeri, C., Storey, D. F., '*Optimising a Gas Pipeline Rehabilitation Program - a New Approach*', 3rd International Conference on 'Pipeline Rehabilitation and Maintenance', Abu Dhabi, May 1999.

4. Taylor, S. A., '*Worldwide Rehabilitation Work is Undergoing Major Changes*', Pipeline Industry, February 1994, p25.

5. Kiefner, J.F., Bruce, W.A., Stephens, D.R., "*Pipeline Repair Manual*", American Gas Association Line Pipe Research Supervisory Committee Pipeline Research Committee, Catalogue No. L51716, December 1994.

6. http://www.clockspring.com/proven.html

7. http://www.plidco.com/

8. Paisley, D., Barrett, N. and Wilson, O., "*Pipeline Failure: The Roles Played by Corrosion, Flow and Metallurgy*", paper No. 99018, *NACE '99*, San Antonio, Texas, April 1999.

9. Corder, I., "*Repairing Transmission Pipelines with Epoxy Filled Shells: The Safest, Best and Cheapest Method*" Institution of Gas Engineers 58th Autumn Meeting, Wembley Conference Centre, November 1992.

10. Hawke, B., Stoves, D., and Vranckx, W., '*Extending the application of epoxy grouted pipeline repair sleeves*'. To be published.

11. ANSYS Version 5.5 User Reference Manual.

12. Stoves, D. "*Tensile Tests on Epoxy Grouts DG38 and DG2088 at Elevated Temperature and Comparative Hardness Tests*" Confidential report produced for PII.

13. Fax from PII to R. Palmer-Jones (APA), dated 3/4/98, "*Summary of tests carried out on samples taken from field installed epoxy filled shell repair*". Confidential to PII.

14. Corder, I., "*The Development of Epoxy Filled Repairs for Transmission Pipelines*", BG Research and Technology, Report Number ERS R.2734, January 1985. (Confidential to BG and PII).

15. Email from Dominic Paisley (BP) to R. Palmer-Jones (APA), dated 3/8/98, "*Pipeline Data.*"