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PIPELINE REHABILITATION PLANNING

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Abstract

An operator faced with an onshore pipeline that has extensive damage must consider the need for rehabilitation, the sort of rehabilitation to be used, and the rehabilitation schedule.

This paper will consider pipeline rehabilitation based on the authors' experiences from recent projects, and recommend a simple strategy for planning pipeline rehabilitation.

It will also consider rehabilitation options:

- External re-coating
- Internal lining
- Internal painting
- Programmed repairs

The main focus will be external re-coating. Consideration will be given to rehabilitation coating types, including tape wraps, epoxy, and polyurethane.

Finally it will discuss different options for scheduling the rehabilitation of corrosion damage including:

- The statistical comparison of signals from inspection pigs.
- Statistical comparison of selected measurements from inspection pigs and other inspections.
- The use of corrosion rates estimated for the mechanisms and conditions.
- Expert judgement

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1. Introduction

There are 3.5 million km of transmission pipelines around the world. This system has been providing safe reliable transport for hydrocarbons for 100 years. A large proportion of that pipeline system has reached, or will soon reach, the end of its design life. Many of the pipelines operate in harsh environments, transport corrosive products, and as a result have suffered extensive corrosion damage. Oil and gas reserves are predicted to last for another 40 to 60 years. Consequently, much of the worlds existing pipeline infrastructure will be required to continue operating for many years to come. Rehabilitation or replacement is therefore critical for ensuring continued, safe reliable operation.

A great deal of work has been done on extending pipeline life by developing inspection technologies such as intelligent pigs, methods for recoating pipelines, techniques for internal painting, and hydrotesting regimes that will detect critical cracks. This wide range of options, the costs associated, and the potential consequences of a failure, mean that a pipeline operator has to proceed very carefully when faced with an extensively damaged pipeline. Unfortunately the most difficult time to thoroughly review the situation, and all the options, is when faced with an extensively damaged pipeline, and an urgent need to ensure continued safe operation.

This paper provides an overview of some of the rehabilitation issues that should be considered and suggestions as to how they could be approached. A strategy is recommended that should ensure that a sensible, justifiable, plan is developed. This strategy is shown in Figure 1.

In this paper rehabilitation is considered to be a specific planned programme of extensive re-coating or repairs intended to significantly improve the condition of the pipeline.

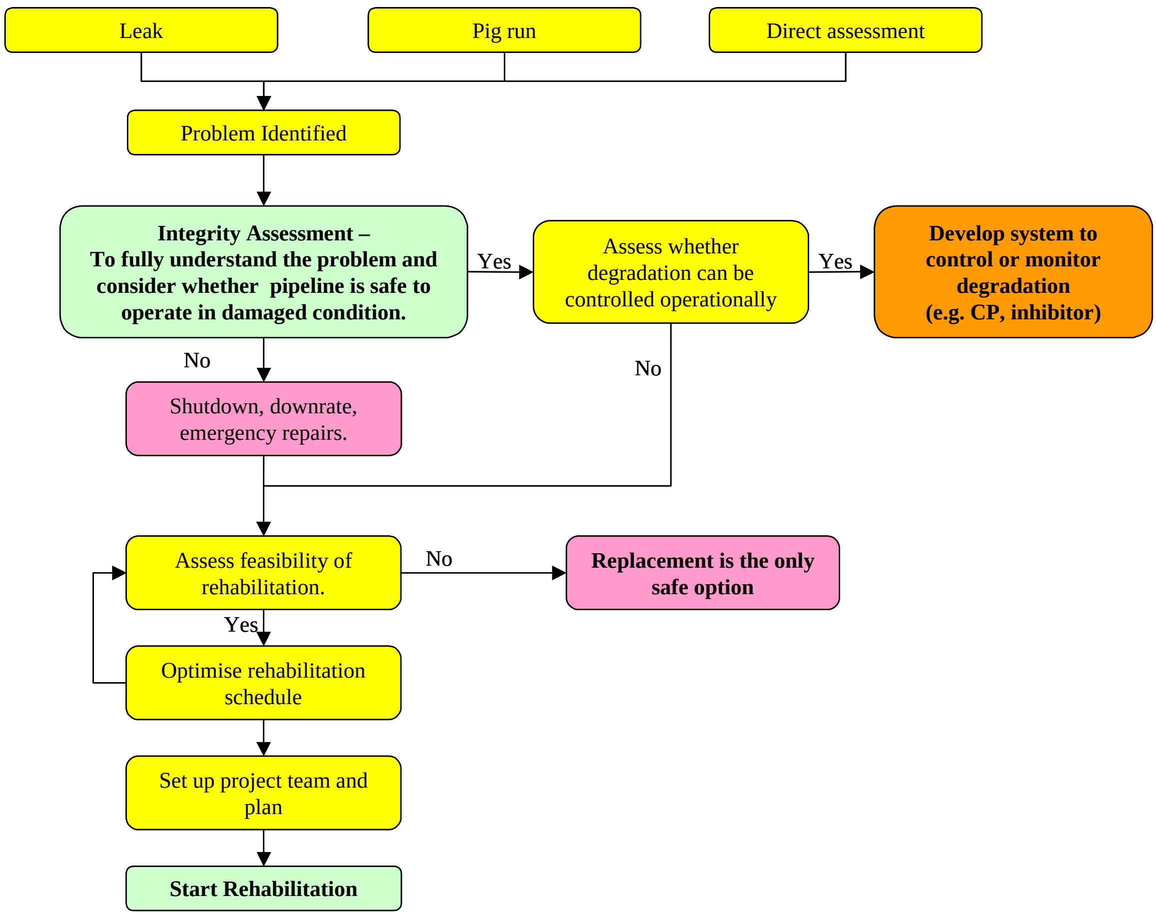

Figure 1: Rehabilitation Planning

This paper will consider pipeline rehabilitation based on the authors' experiences from recent projects[1, 2, 3, 4], and recommend a simple strategy for planning pipeline rehabilitation.

It will also consider rehabilitation options:

- External re-coating
- Internal lining
- Internal painting
- Programmed repairs

The main focus will be external re-coating. Consideration will be given to rehabilitation coating types, including tape wraps, epoxy, and polyurethane.

2. Identification of A Problem

A pipeline operator may believe that rehabilitation or replacement must be needed, because the pipeline has reached the end of its 25 year design life. This may be a reason re-validation but rehabilitation only needs to be considered if a major problem is identified. The continuing safe operation of many pipelines that are more than 50 years, and which have field-applied coatings, is sufficient evidence that age alone is not a good reason for rehabilitation. Penspen operates a pipeline in the UK built in the 1940s. The pipeline is used as part of a system supplying aviation fuel to an airport. Despite its age, and the extensive development that has taken place around it, the pipeline has a long history of safe and reliable operation. This is just one example of many around the world.

Problems with a pipeline may be identified following a leak[1], an internal inspection, or by direct assessment. Having identified a problem it is vital to understand the root cause (or causes) and the severity, to determine whether any action is required, and if so how quickly.

The main problems that may be addressed by rehabilitation are external coating degradation, and internal corrosion.

3. Is Rehabilitation Needed?

There are three key issues that will determine whether rehabilitation is needed:

1. Current condition
2. Future degradation
3. Feasibility of rehabilitation

The current condition and the future degradation can be evaluated by carrying out a detailed integrity assessment. The results of this assessment will also be very helpful in determining the feasibility of rehabilitation.

3.1 Integrity Assessment

Pipeline integrity is ensuring a pipeline is safe and secure. It involves all aspects of a pipeline's design, inspection, management and maintenance[5]. A detailed integrity assessment will provide much valuable information, for example on the condition of a pipeline, and the ability of the team maintaining the line to keep it in good condition, that can inform any rehabilitation plan.

A key part of the integrity assessment will be an assessment of the 'fitness-for-service' or 'fitness-for-purpose' of the pipeline. This is the element that we will review in this paper.

3.2 Fitness for Purpose[1] Assessment

A 'fitness for purpose' assessment (better described as an 'engineering critical assessment' [6,7]), calculates the failure condition of a structural defect and compares it with the operating condition of the structure.

The fitness for purpose of a pipeline containing a defect may be estimated by a variety of methods ranging from previous relevant experience, to model testing, to engineering critical assessments, where a defect is appraised analytically. These latter assessments can be by:

[1] We use 'fitness for purpose' in the pipeline integrity business as 'a failure condition will not be reached during the operation life of the pipeline'. Note that fitness for purpose also has a (different) legal meaning, particularly in the construction business, with differing liability.

- Generic methods [8,9],
- Traditional pipeline industry methods [10-11],
- Recognised pipeline codes developed using the traditional methods [6,7],
- Publications from pipeline research groups [11-15],
- 'Best practice' publications emerging from Joint Industry Projects [16-19].

3.3 Key Considerations

Any operator conducting a fitness for purpose calculation should consider the following[20, 21, 22]:

- Understand the defect – what caused it, how it may behave.
- The engineer doing the assessment - experience, training, independence, overview, support.
- Assessment methods – use best practice.
- The consequences

Further details of these considerations are given in Reference 20.

3.4 Input Data

The type and level of detail of information that is required in any assessment depends on the depth and scope of the assessment. The issues that typically should be considered include[20]:

1. The pipeline – geometry, materials, operation, environment, history, etc..
2. Stresses – all loads acting, future changes, cyclic loads, etc..
3. Inspection method – capability and accuracy.
4. Defect – cause, dimensions, type, location, growth, etc..
5. Consequences – leak, ignition, pollution, etc..

Further details are given in Reference 20.

3.5 Considerations when Using Smart Pig Data.

The following points should be considered when using smart pig data to aid a fitness-for-purpose assessment[20]:

1. Pigs cannot detect all defects, all of the time.
2. Pigs measurements have associated errors.
3. Pigs cannot discriminate between all defects.
4. Treat simple defect assessments by pigging companies (e.g. the ERF) with care – they may not be appropriate for all defects and all pipelines.
5. Use all available inspection data – e.g. past inspection reports.
6. Location – defect location accuracies of pigs vary and have errors.
7. Origin – always be able to explain the presence of a reported defect.

3.6 Benefits of the Integrity Assessment

An integrity assessment that takes into account the issues outlined above will:

1. Provide the operator with best possible understanding of the current condition of the pipeline, and whether it is safe to continue to operate it.
2. Identify degradation mechanisms and give conservative estimates of the rate of degradation.
3. Identify other issues that may affect the feasibility of rehabilitation (e.g. location)

4. Feasibility Of Rehabilitation

The feasibility of long-term rehabilitation will depend on a number of factors, including:

Severity and Extent of Damage – the damage may be so severe and extensive that simple rehabilitation is not sufficient. Many structural repairs (e.g. clockspring^{TM}) may be required to strengthen the pipeline, and replacement may be cheaper.

Degradation Rate – The rate of degradation may be so high that it is impossible for the rehabilitation programme to be completed in time.

Access – Difficult access (for example due to seasonal flooding) may limit the rate of rehabilitation, but a new pipeline may be able to take a different route avoiding access problems.

Climate – The weather conditions may be too cold to allow satisfactory curing of coatings, or too wet to enable rehabilitation teams to ensure a satisfactory surface finish.

Availability of Technology – The machinery, products, or personnel required to allow high quality rehabilitation may not be available in some areas of the world.

Organisational Issues – Rehabilitation is often required as a matter of urgency to prevent further degradation. It may be quicker and easier to organise the design and construction of a new pipeline, than to set up a special rehabilitation project that may involve work on an operating pipeline.

Future Degradation – The possibility of other problems developing in the future that would require replacement of the pipeline should be considered. For example if it is anticipated that a sour product may be transported in the future, and the existing pipeline is not made of a material resistant to cracking, then money spent on an external coating rehabilitation may be wasted.

Regulatory Regime – The local regulators may not allow rehabilitation.
If consideration is given to these issues and any others that may be identified then it should be possible to identify whether rehabilitation is feasible. The above issues are usually assessed with a cost and risk benefit.

5. Cause of Defects and Degradation Rate/Control of Degradation

The integrity assessment should consider the cause of the defects or damage and the rate of degradation. This will be critical to deciding: whether the degradation can be halted; whether rehabilitation is feasible; and the type of rehabilitation that is appropriate.

There are a many of different causes of damage that may lead to a requirement for rehabilitation. These include:

1. External Corrosion
2. Internal Corrosion
3. Cracking
4. External Damage
5. Ground Movement

In this paper we will look at external corrosion in some detail, we will consider some aspects of internal corrosion but we will not consider cracking, external damage, ground movement or any other form of damage, as these latter types of damage are usually addressed using local repairs rather than rehabilitation.

5.1 External Corrosion

External corrosion is a common problem for our aging pipelines: The main cause is an inadequate external coating. Problems can be made worse by aggressive local soil conditions, high operating temperatures, and poor cathodic protection. Correctly identifying the root cause of the problem, the corrosion mechanism (or mechanisms) at work, the way the defects will grow, and the way they may fail, provides valuable information that can be used in the rehabilitation planning process.

5.1.1 Coating Type and Condition

Understanding the coating type and the condition will help to ensure that the corrosion process is understood and that the correct approach is taken to rehabilitation. For example a common response to discovering external corrosion is to increase the level of cathodic protection. However if the corrosion is taking place underneath a disbonded coating then the cathodic protection system will be ineffective.

All coating types can degrade; however, older coatings, and in particular coating applied 'over the ditch' (i.e. on site during construction), do not perform as well as modern factory applied epoxy and three layer polyethylene coatings.

An example of a poorly applied tape coating is shown in Figure 2

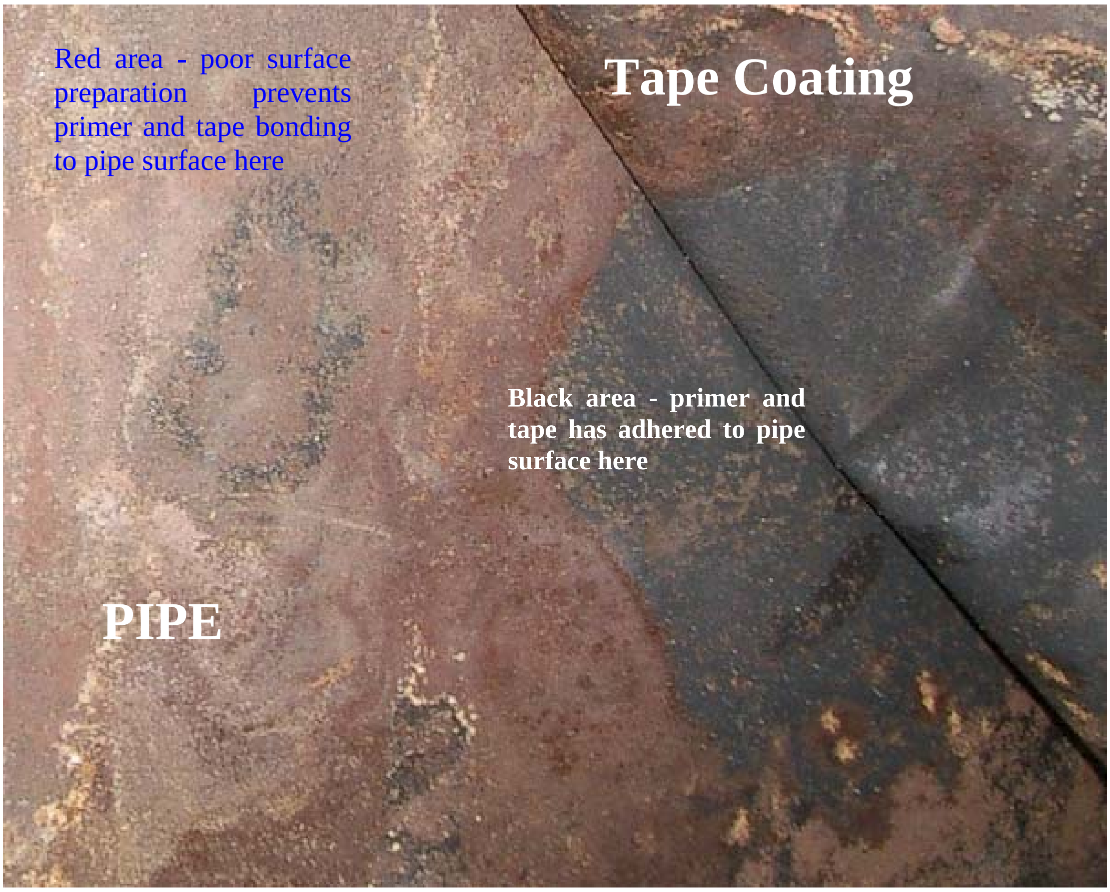

Figure 2 15 Year Old Tape Coating

This type of tape coating is prone to numerous problems including:

- Poor general adhesion due to poor surface preparation and primer application
- Tenting at girth welds and seam welds (straight or spiral), see Figure 3.
- Rucking and disbonding due to soil stress
- Shielding of Cathodic protection system when disbonded

Figure 3 Tape Coating Tenting at Seam Weld

The performance of different coating systems varies significantly; some basic factors to consider are given in Table 1.

Table 1 Coating Assessment Guide

Factor	**Type**	**Problem Potential**
Coating Type	Fusion Bonded Epoxy	-Blistering
	Three Layer Polyethylene	-disbondment of FBE primer on low density PE
	Coal Tar and Asphalt Enamel	-coking of the coating due to overheating during application -variable thickness around the circumference on over the ditch coating -poor adhesion on wire brushed surface
	Tape Wrap	-poor adhesion at overlap particularly on butyl rubber tapes -disbondment due to soil shear stress (rucking)
Soil Condition	Clay	-can causes high soil shear stress
	Wetting and drying	-can causes high soil shear stress
Operating Conditions	Temperature	-all coatings have an upper temperature limit and lose performance as this limit is approached

By considering these basic factors the potential for long term problems can be identified.

5.1.2 External Corrosion Rates

Corrosion rates will vary from defect to defect, depending on the conditions at each location. The estimation of corrosion growth rates based on intelligent pig data is increasingly common. Corrosion defects reported by two pig runs can be compared and a corrosion rate estimated. This type of pig data analysis is valuable for predicting when repairs or rehabilitation should be done, when the pipeline should be re-inspected, and helps extend the economic life of the line. The analysis is done using the reported defect sizes, or using the sensor signal data, and comparing signals to derive a change in signal and hence a change in defect depth[24].

However, it must be treated with caution, and knowledge of corrosion processes and pipeline operation must be incorporated into any assessment:

a) Methods based on the sized defects must consider the corrosion process, treat the data consistently, and consider the sizing issues discussed above[25]. For example, pig accuracy and tolerances will invariably produce anomalies such as negative corrosion rates (the corrosion is decreasing in size) for some locations.

b) Where an analysis is based on an unprocessed signal[2], the validity of this method must be demonstrated with practical test results (signals from a sample of defects before and after a known increase used to give an estimated growth that can be compared with the actual growth): to date, the authors have seen no such validation.

Some typical corrosion rates from the literature for bare steel with no cathodic protection are given in Table 2.

Table 2 Published Corrosion Rates[26, 27, 28, 29]

Corrosion mechanism or soil type	**Water types**	**Corrosivity**	**mm/yr**
Microbiologically Induced Corrosion			upto 1.0
AC Corrosion			upto 1.5$^+$
Salt marshes, salty peat, swamps	Sea-bed	High	0.5
Salt loams, wet loams, clays, peat	Brackish water	Moderate	0.2
Compact loams, clays	Fresh water, riverbed	Slight	0.1
Sandy loams, gravel		Slight	0.05
Limestone, dry sand, rock debris		Not expected	(≤) 0.05
Note: These are at ambient temperatures. Corrosion rates will increase with increases in temperature. For example, a 10ºC increase in temperature can double the corrosion rate. $^+$Higher corrosion rates have been observed in the laboratory			

This type of information can be used where repeat inspections are not available, or to ensure that rates estimated from repeat inspections are reasonable.

5.2 Internal Corrosion

Methods are available for estimating internal corrosion rates; for example, the de Waard and Milliams[30] method for sweet (CO_2) corrosion. We will not review this subject in any detail in this paper, but for internal corrosion estimates it is important to consider the process variables, the fluids in the pipeline, the pressure, the temperature, the flow rate, the flow regime (turbulent, stratified etc.), and in particular the presence of water. If the presence of water occurs on an intermittent basis then the corrosion rate can be calculated in two ways: an average over the whole period; or during the presence of water only. If the presence of water is likely to increase then the latter will be a more accurate assessment.

5.3 Defect Shape and Failure

The type of corrosion will affect the shape of the defects developed and the way those defects may fail. For example microbially induced corrosion typically produces steep sided, deep defects often with a relatively small diameter (see Figure 4). The corrosion rate may be high, but these defects have a limited effect on the strength of the pipe and will only fail when they have penetrated all of the way through the pipe wall. An area of general corrosion (see Figure 5) may grow more slowly, but may weaken the pipe sufficiently to cause a burst or rupture when it has only partially penetrated the pipe wall. This difference is illustrated in Figure 6.

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[2] Inspection pigs carry sensors that produce electrical signals when a defect is encountered. These signals must be processed and interpreted to provide estimates of the defect depth or the remaining wall thickness. Changes in unprocessed signals from inspections carried out at different times can be compared, and have been used to give estimates of corrosion growth rates; however, changes can occur even when there has been no physical change in the pipeline [1].

Figure 4 Microbially Induced Corrosion

Figure 5 General Corrosion

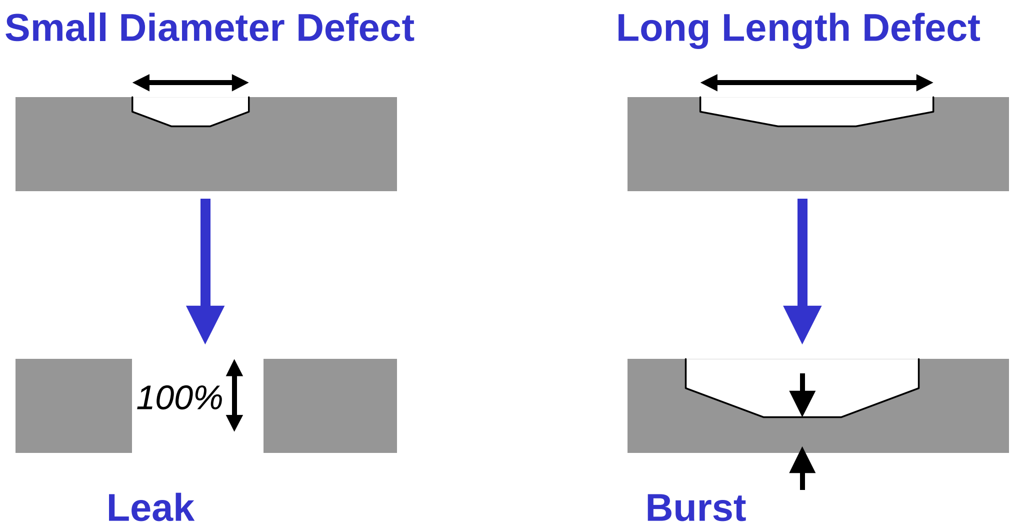

Figure 6 Growth of Defects to Failure

6. Rehabilitation Options

There are many options for the rehabilitation of a pipeline with extensive damage. In this paper we will focus on the replacement (extensive, or localised) of the external anti-corrosion coating. Then, some comments will be made on:

1. Programmed repair campaigns
2. Internal lining
3. Internal painting

Other activities, such as the excavation of long sections of pipeline to relieve stresses caused by ground movement, can also be considered to be rehabilitation, but are not covered in this paper.

6.1 Coating Replacement

The desirable properties of a new coating include:

- An effective electrical insulator
- An effective moisture barrier
- Can be applied in the field
- Resist development of “holidays” with time
- Good adhesion to the pipe surface
- Must be resistant to disbonding under the applied cathodic protection
- Must not support the growth of bacteria
- Must be resistant to soil stresses at the operating temperature of the pipeline
- Must be non toxic to the environment

In addition the generic coating should have a successful track record for coating rehabilitation works.

6.1.1 <u>Tape Systems</u>

The most popular coating used for rehabilitation has been tape. The most widely used tape systems use either PVC or PE with an adhesive backing. The adhesive is usually bituminous or butyl rubber type. Tapes have the advantage that they are:

- Surface tolerant. However, they show poor adhesion, relative to liquid applied systems, on well-prepared surfaces, so that the difference when applied to poorly prepared surfaces is not as significant.
- They can be applied in the field without the need for specialised equipment (see Figure 7).

Figure 7 Field Applied Tape Coating

Their disadvantages include:

- Variable surface preparation can cause problems with adhesion.
- Tapes with a butyl rubber adhesive often have poor adhesion at the overlap (see Figure 8).
- They are generally not suitable for operating temperatures above 50ºC to 60ºC.
- Most tapes have a low resistance to soil stresses.
- They do not conform to heavily corroded surfaces and will bridge discontinuities, undermining the adhesion quality and performance.
- While they do not require specialist equipment, automated tape wrapping machines are required for consistent application quality, particularly on large diameter pipelines (>12”).

Figure 8 Poorly adhered tape refurbishment coating

6.1.2 Coal Tar Enamel

Coal tar enamel coatings have been used for rehabilitation, but have fallen out of favour due to safety issues (handling hot tar on site) and toxicity fears.

6.1.3 Liquid Epoxy Systems

Liquid epoxy systems are being used increasingly in the field for coating rehabilitation.

The advantages of epoxy systems are:

- In general terms they are suitable for temperatures up to 90ºC under continuously moist conditions.
- They show superior resistance to soil stressing and impact damage.
- They have low current requirement for cathodic protection
- They are resistant to cathodic disbondment
- They have very good adhesion
- They resist the development of holidays with time
- Under favourable application conditions, they can be touch dry in less than an hour and fully cured in 1-2 days

The main disadvantages are:

- They require a minimum surface preparation standard of ISO8501-1 grade Sa2½ (a visual surface standard of cleanliness equivalent to a "white metal finish")
- The surface must not be contaminated with soluble salts
- They are sensitive to humidity and moisture during application
- They will not cure at low temperatures (typically <5ºC)
- Specialist application equipment may be required, e.g. in order to achieve a thickness of 750µm plural component hot spray equipment is required[3].

6.1.4 Liquid Polyurethane Systems

Liquid polyurethanes are also frequently used for pipeline coating rehabilitation. Film thicknesses of 1-1.5mm are often specified although greater thickness can be achieved with solvent free products. In general terms solvent free polyurethane's are suitable for pipeline operating temperatures up to 80ºC. The polyurethane systems with the longest track record for pipeline rehabilitation work contain coal tar; the coal tar lowers the overall cost of the coating without any adverse effect on the coating properties. However, coal tar is being used less frequently in coating formulations nowadays because of the carcinogens contained within it and the toxicity of the fumes produced when coal tar is heated. Polyurethanes, which are free of any coal tar products, are increasingly being specified for pipeline coating applications.

Advantages of solvent free polyurethane systems include:

- Touch dry in a few minutes, fully cured in a few hours
- Very abrasion resistant and resist soil stresses
- They have very good adhesion, but not as good as epoxies
- Very low cathodic protection current requirements
- Resistant to cathodic disbondment

The main disadvantages are similar to epoxy systems:

- They require careful surface preparation to Sa2½
- The surface must not be contaminated with soluble salts
- They are sensitive to humidity and moisture during application
- Specialist application equipment is required.
- Increased thickness is required to ensure adequate coverage at surface discontinuities

[3] Because of the tendency for some liquid applied systems to provide limited coverage at sharp edges (for example at heavily corroded sections and on weld seams), it is customary to specify a thicker coating than would be specified for a new pipeline. While on a flat surface 750 microns may be considered adequate, 1250 microns is likely to be more appropriate to ensure adequate cover on all surface imperfections

6.2 Surface Preparation and Coating Application

Surface preparation is critical in any recoating exercise. In general, the better the surface preparation, the better the coating system performance will be. In order to refurbish the coating on sections of a pipeline, the sections will need to be excavated and:

- The existing coating removed.
- The pipe surface cleaned and the surface prepared to an acceptable standard for the subsequent recoating operation
- The new coating has to be applied to an acceptable standard
- The pipe needs to be backfilled and the right of way reinstated.

These works could be carried out manually or be automated. Automation is strongly preferred, to remove the human element, maintain a high quality, and minimize waste and damage to the environment.

6.2.1 Removal of Existing Coating

One of the most effective methods for tape coating removal is to use high pressure water jetting operating at 1,400bar. Not only does this remove the existing coating it also removes corrosion products, soluble salts and other contaminants from the surface of the pipe and leaves only well-adhered primer. The removal of soluble salts is necessary to ensure the acceptable performance of the subsequently applied coating systems.

The water must be potable water grade and be free of contaminants such as chlorides and anaerobic bacteria.

Some coating types can be removed by hand using scrapers, but this is generally unsatisfactory since it is very difficult to completely remove the existing coating.

Some old coatings contain asbestos, the safe and environmentally acceptable handling and disposal of removed coatings should be considered.

6.2.2 Surface Preparation

The surface should be prepared to an Sa2½ (white metal) standard using a suitable blast medium. The blast medium is often procured locally and should to be free from salts, should be environmentally friendly and must produce an angular profile.

If an automated system is used then recovery and partial recycling of the blast medium can be carried out. If the blasting is done manually then there will be no recovery of the blast medium and it must therefore be expendable and non hazardous. An example of manual blast cleaning is shown in Figure 9.

Figure 9 Blast cleaning in-situ on a large diameter pipeline (photograph courtesy Copon)

6.2.3 Coating Application

Automated application of the coating ensures a more even film thickness but may not be suitable for short lengths of pipe. An example of automated coating application is shown in Figure 10. The maximum unsupported length of pipe that can be excavated for refurbishment will depend on the pipeline material, diameter, and thickness, and the product in the pipeline. Manual application will give a more variable film thickness but will allow the operator to apply a thicker film in heavily pitted areas, where brush application of a first coat is also recommended.

The ideal conditions for coating application are warm (20 ^{o}C) and dry, as two pack liquid paint systems[4] can have extended and impractical cure times at low steel temperatures (<5^{o}C). No coating system should be applied where the steel temperature is below the dew point:- pipe pre-heating will be required under such circumstances.

Figure 10 Automated Coating Application (photograph courtesy Copon)

6.2.4 Quality Control

The high quality coating systems considered most suitable for rehabilitation work need careful application by experienced or trained personnel using specialist equipment. Therefore rehabilitation should be let to a company experienced in this sort of work or one who can bring in suitably qualified staff. It is usual practice to use a local contractor with 3-4 external specialists, and buy-in or rent the necessary specialist equipment. This will require a period of training to bring the skills of the local contractor’s workforce up to the required standard before pipe coating refurbishment commences.

To ensure quality is maintained an independent coating inspection company should be employed to provide experienced coating inspectors to oversee the pre qualification of the coating application procedure and ensure the production coating quality.

6.3 Programmed Repair Campaign

In some cases it may be that coating replacement will not prevent degradation (for example if there is some form of internal corrosion), or a rolling programme of spot repairs is more cost effective than extensive coating replacement.

6.3.1 Repair Selection

The repairs used must be selected to be suitable for the damage being repaired. So if internal corrosion is being repaired then the repair system must be able to prevent a failure should that corrosion get grow through wall, and the product enter the repair. Guidance on the suitability of different repairs for different defects is given in a variety of codes (e.g. API 1160, see Table 3): note that some of this advice is contradictory.

[4] Paints that require 2 parts to be mixed before use.

Table 3 Permanent Repair Methods (API 1160)

	Weld Repair[1]	Type A Sleeve[2]	Type B Sleeve	Composite[2]	Hot tap
External Defect[2] (<=80%wt)	Y	Y	Y	Y	Y[5]
Internal Defect[2] (<=80%wt)	N	N	Y	N	Y[5]
External Defect[2] (>80%wt)	Y[1]	N	Y	N	Y[5]
Internal Defect[2] (>80%wt)	N	N	Y	N	Y[5]
Leaks	N	N	Y	N	N
Cracks	N	N	Y	N	N[6]
Girth Weld Defects	N	N	Y	N	N
Dents	N	Y[4]	Y	N[7]	Y[8]
Dents with defects[3]	N	Y[4,3]	Y[3]	N	Y[8]

1. YOU ALWAYS NEED A MINIMUM WALL TO WELD ONTO – CHECK WITH EXPERT. API 1160 LIMITS APPLICATION TO WT>0.181", AND THIS WILL GENERALLY LIMIT METHOD TO <80%WT DEFECT DEPTHS.
2. INDUSTRY PRACTICE IN N AMERICA IS TO LIMIT TYPE A SLEEVES AND COMPOSITE REPAIRS TO DEFECTS NOT EXCEEDING 80% WT
3. ANY DAMAGE IN THE DENT MUST HAVE BEEN REMOVED, E.G. BY GRINDING. Care must be taken when grinding onto live pipelines. Depressurisation may be necessary.
4. DENT MUST BE FILLED WITH INCOMPRESSIBLE MATERIAL
5. BUT NOT ON A WELD
6. CRACKS THAT ARE NOT LEAKING CAN BE HOT TAPPED TO REMOVE CRACK
7. SOME COMPOSITE REPAIRS CAN BE USED ON STRAIGHT PIPE WITH DENTS, IF THEY ARE FILLED WITH INCOMPRESSIBLE MATERIAL, AND PROVEN BY TESTS TO BE PERMANENT
8. IF DENT CAN BE REMOVED COMPLETELY

There are some repair methods that are not adequately covered by guidance such as that given in API 1160. The epoxy filled sleeve repair developed by British Gas is one example (see Figure 11). It is similar to a type B sleeve in that it can be used for the repair of cracks and girth weld defects; however, it should be used with caution on deep internal defects or through wall defects. Another example of a repair not covered by the guidelines is the pre-stressed steel sleeve developed by Petroline. It is similar to a type A sleeve in that two half shells are assembled around the defective area and welded together, but not welded to the pipeline. However, before they are joined together the shells are heated. As they cool they compress the pipeline and transfer stress away from the defective area. This repair has been used for a wide variety of defects including cracks[31].

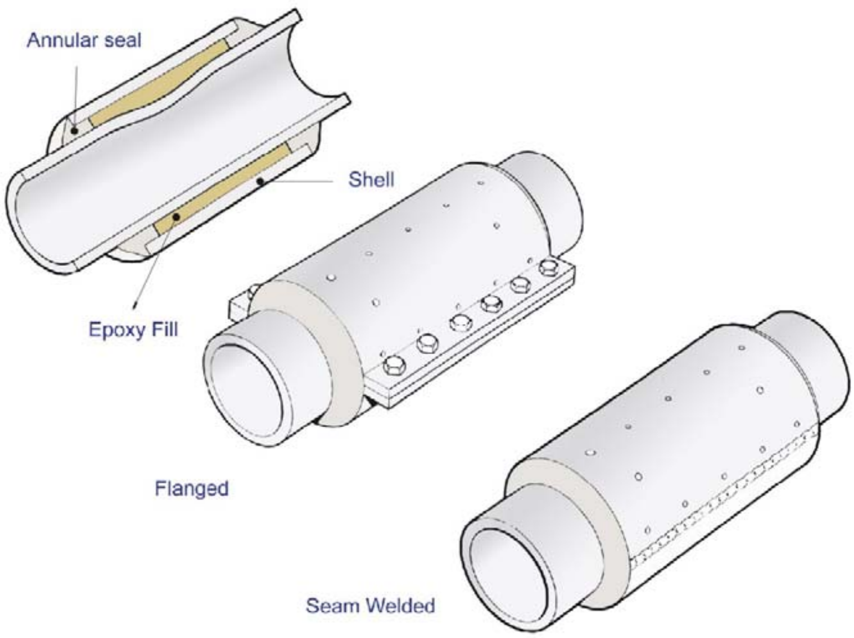

Figure 11 Epoxy Filled Sleeve Repair[23]

6.3.2 Other Issues for Programmed Repairs

Some other issues to consider as a part of a repair programme are:

- The programme must be scheduled to ensure that defects are repaired before they become critical.
- Procedures for assessing defects following excavation will be needed to ensure that structural repairs are suitable and are only installed when needed (the inspection pig may have over-sized or under-sized the defect, or incorrectly classified it).
- Regular re-inspection may be required; consequently, keeping good records of what has been repaired, and where, is vital.

6.4 Internal Lining

There are several forms of internal lining including cured in-place liners, close-fit polymeric liners and loose-fit liners. We will briefly look at some of the features of close-fit internal liners:

- Proven technology with a good track record in water injection pipelines.
- Straight pipeline sections of 400m to 800m can be lined in one operation.
- They rely on the strength of the steel carrier pipe.
- Rapid installation possible.
- Gas permeation through lining requires venting.
- Cannot line hot bends or tees.
- Large internal weld beads can be a problem.
- Future internal inspection of the steel pipe is not possible.

For more information on internal liners see Reference 3.

6.5 Internal Painting

Internal painting involves the use of pig trains using aggressive cleaning chemicals followed by slugs of paint to give a thin film paint coating on the inside of the pipeline. Internal painting in-situ has been used on a number of occasions with mixed results

The process has the following drawbacks:

- Poor surface preparation – relies on mechanical scraping by pigs and chemicals. There is no grit blasting to ensure a white metal finish
- Poor inspection – it is very difficult to closely inspect the inside of the painted pipeline
- Variable coating thickness
- Thin film paint systems are never considered to have 100% coverage and so it is inevitable that corrosion will continue at coating defects, consequently continued inhibition required.

However, internal painting has been used successfully and does offer some advantages:

- Will greatly reduce the extent of internal corrosion.
- Improves flow.
- Allows internal inspection.

In summary internal painting has a number of problems, but it may be appropriate to consider it in certain situations.

7. Scheduling

The rehabilitation schedule[5] has to be designed first and foremost to ensure that defects are not able to grow to a dangerous size. The time it will take for a defect to grow to a critical size is known as its ‘remnant life’, and the most important input is the corrosion growth rate, or rates, assumed. Corrosion growth rates have been discussed in Section 5.1.2. Some important issues to consider when estimating remnant lives are:

- Is it better to use a deterministic or probabilistic method to calculate remnant life?
- Is it appropriate to use more than one growth rate, i.e. are there different corrosion mechanisms?
- Is it appropriate to use more than one defect acceptance limit?
- How long to the next inspection.

7.1 Deterministic or Probabilistic Remnant Life Prediction

Scheduling can be based on statistical estimates of corrosion growth rates, based on multiple defect measurements and the accuracy of any measurement. These assessments will give future probabilities of failure for each defect considered.

An example of the results of a probabilistic assessment is given in Figure 12.

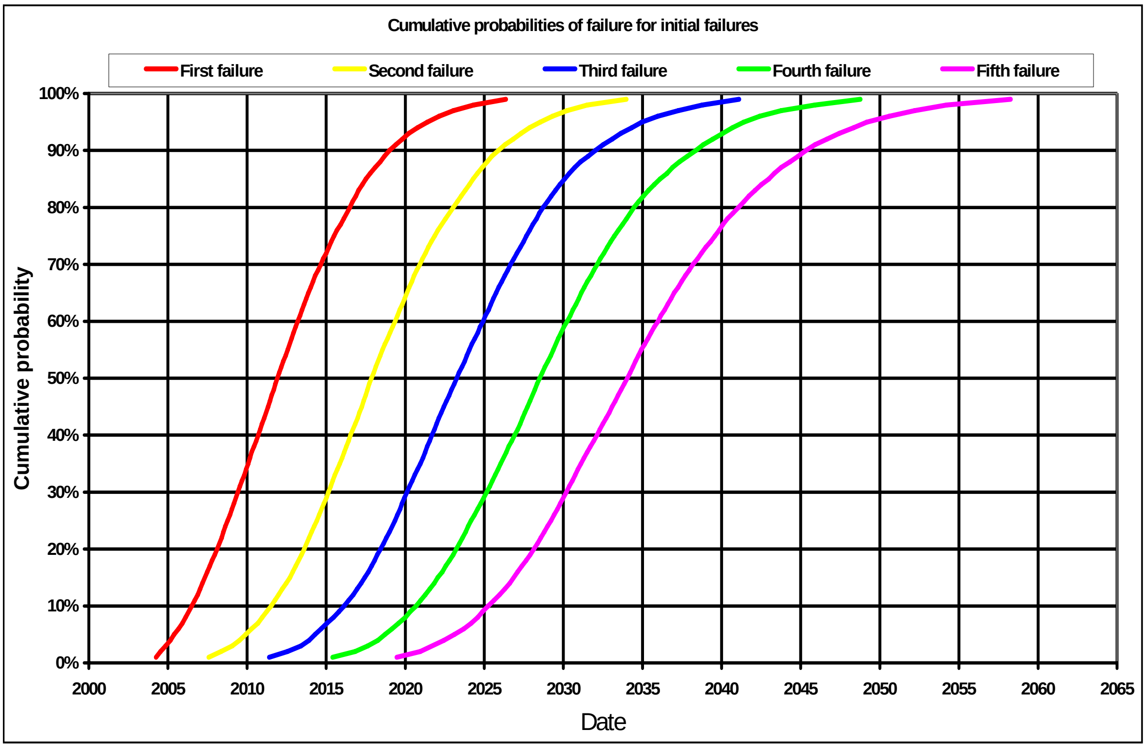

Figure 12 Cumulative Probabilities of Time to Failure

Probabilistic methods have the advantage of giving a level of quantification to the uncertainty associated with the assessment; however, the difficulty is in deciding what is an acceptable probability that a defect has become unacceptable, or failed.

The alternative is to use a deterministic method, where any uncertainty in the defect sizing and the corrosion growth rate is accounted for in the conservative choices and safety factors used in the assessment, e.g. by adding the inspection tool tolerance to the sizes of all of the defects. A deterministic method has the advantage of providing a clear answer; the difficulty is in ensuring that the assessment is not overly conservative.

[5] It should be noted that some codes and regulations require defects to be repaired within a specified time scale, e.g. API 1160.

7.2 Selection of Corrosion Growth Rates

As discussed previously corrosion growth rates may be derived from inspection, from testing, or from the literature. Whatever the growth rate used it is always sensible to check with an experienced corrosion engineer that the rate is credible (not impossibly high) and that it is not too low (conditions may now allow a faster rate). Consideration should also be given to using more than one corrosion rate, since it is possible that more than one corrosion process may be at work, for example it is not unusual to have both general corrosion and Microbially Induced Corrosion at the same time.

7.3 Selection of 'Failure' Criteria

The remnant life will generally depend on the corrosion rate assumed and the criteria used to define an unacceptable defect. A good example of this is the corrosion defect depth limit in ASME B31.G of 80% of pipe wall thickness. This code considers any defect that is deeper than 80% of the pipe wall to be unacceptable. In a thin wall pipe (e.g. 5 mm) this is a very sensible limit since the remaining wall thickness may be just 1 mm, and a small amount of corrosion growth would be needed for the defect to fail. Some subsea pipelines however, are 25 mm thick or more, and a defect 80% through the wall would still leave 5 mm of remaining wall. The limit of 80% of thickness is not a technical limit, and tests and analyses have shown that, provided the defect is short, much deeper defects can be tolerated.

Consequently, the 'failure' criteria should be selected taking account of the pipeline parameters, the type of corrosion, the shape of the defects produced and the accuracy of the measurement. It may be appropriate to use more than one criterion if there are different corrosion mechanisms at work.

7.4 Allow Time for Action

Schedules produced for rehabilitation and re-inspection must be realistic and allow time for action following inspection (it may take several weeks to complete a number of repairs) or for projects to be delayed.

8. Conclusions

Our experiences on recent projects have led us to three key conclusions

1. A planned and structured rehabilitation strategy, as proposed in Figure 1, is essential.

2. A detailed integrity assessment is a vital part of the strategy, and helps to fully understand the problem.

3. Good rehabilitation coating requires good surface preparation. Coatings should be selected based on the pipe condition, the ground conditions and the service conditions.

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